Final Staff Assessment

BLYTHE ENERGY PROJECT PHASE II

Application For Certification (02-AFC-1)
Riverside County

Filed jointly by the

CALIFORNIA ENERGY COMMISSION

and the

WESTERN AREA POWER ADMINISTRATION

STAFF REPORT

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Western AREA POWER ADMINISTRATION

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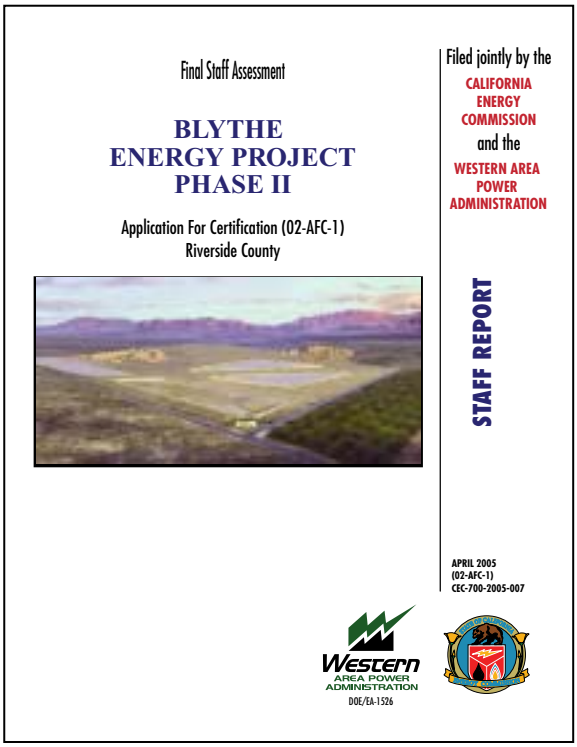

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EXECUTIVE SUMMARY

This report contains the Energy Commission staff's independent analysis and recommendation on the Blythe Energy Project Phase II (BEP II) proposed by Caithness Blythe II, LLC. **This is <u>not</u> the decision document for these proceedings nor does it contain findings of the Energy Commission related to environmental impacts or the project's compliance with local/state/federal legal requirements.** The final decision including findings, will be made by the Commissioners of the California Energy Commission after completion of evidentiary hearings. During evidentiary hearings the Commissioners will consider the recommendations of all interested parties, including those of the Energy Commission staff presented in this document; the applicant; intervenors; concerned citizens; City of Blythe; and other local, state, and federal agencies, before making a final decision on Caithness' Application For Certification (AFC) to construct and operate a nominally rated 520 megawatt (MW) combined-cycle power plant.

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 whether the project conforms with all applicable laws, ordinances, regulations and standards (LORS). The staff also recommends measures to mitigate potential significant adverse environmental effects and conditions for construction, operation and eventual closure of the project, if approved by the Energy Commission. The analyses contained in this document were prepared in accordance with Public Resources Code Sections 25500 et seq.; the California Code of Regulations, Title 20, Sections 1201 et seq.; and the California Environmental Quality Act (Pub. Resources Code § 21000 et seq.) and its guidelines (Cal. Code Regs., tit. 14 § 15000 et seq.).

The BEP II and related facilities 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 (Cal. Code Regs., tit. 14 § 15251(k)).

The BEP II AFC was filed by the applicant Caithness BEP II on February 19, 2002. The project AFC was amended in May 2002 to relocate the BEP II structures to the adjacent parcel and again in July of 2002 to reconfigure the evaporation ponds. On April 15, 2004, the applicant filed a Revision to Section 2.0 (Project Description) of the AFC describing how the project would interconnect to the electrical grid.

The BEP II AFC review process has taken considerably longer than the Commission's standard one year schedule due to changes in the project, incomplete information from the applicant and several major unresolved issues. Staff issued three rounds of data requests to the applicant and conducted several Data Request/Data Response/Issue Resolution Workshops in Blythe, Ontario, and Sacramento. Staff also held numerous conference calls and meetings with the applicant and transmission owning utilities to resolve outstanding issues.

PROJECT LOCATION AND DESCRIPTION

The BEP II site is located within the City of Blythe, approximately five miles west of the center of the City. The 76- acre site is located adjacent to the west side of the Blythe Energy Project Phase I (BEP I), which is owned and operated by Florida Power and Light. BEP II would be operated separately from BEP I, with some shared facilities as described below. The project site is east of the Blythe Airport, which is owned by Riverside County and operated by the City of Blythe. The project site is on an intermediate plateau, about 70 feet in elevation above and west of the Colorado River Valley and the City of Blythe and about 60 feet below the elevation and east of the Blythe Airport. The topography of the project site is flat. (Please refer to **Project Description** Figure 1)

BEP II is a nominally rated 520 megawatt (MW) combined-cycle power plant. The proposed project is adjacent to the approved and operating Blythe Energy Project Phase I (BEP I) that was permitted by the Energy Commission in March 2001. BEP II consists of two Siemens Westinghouse V84.3a 170 MW combustion turbine generators, one 180 MW steam turbine generator and supporting equipment. BEP II may utilize some existing facilities at the BEP I site including the BEP I Control/Administration and Maintenance Buildings. Other BEP I facilities that may be expanded to serve BEP II include the groundwater supply, fire protection facilities and site access roads. Natural gas would be supplied to BEP II plant by the natural gas pipeline constructed as part of BEP I.

As described in the AFC Project Description, BEP II would be interconnected to the regional electricity grid at the Buck Boulevard Substation, located in the northeastern corner of the BEP I site. The federal Western Area Power Administration (Western) constructed the Buck Boulevard Substation as part of BEP I. Additional facilities would be provided in the Buck Boulevard Substation by Western for connection to BEP II. The revised Project Description submitted on April 15, 2004 proposed that BEP II be connected to the future Desert Southwest Transmission Project (DSWTP) via a connection to Western's existing Blythe Substation adjacent to the Buck Boulevard Substation.

Water to operate the proposed BEP II facility would be supplied by two (2) deep on-site groundwater wells each having the capacity to pump up to 3,000 gallons per minute (gpm). Supply and wastewater treatment systems similar to those constructed as part of BEP I would be provided. An additional wastewater evaporation pond would be provided for BEP II.

The BEP II would use about 3,300 acre-feet of water annually for cooling and other purposes. BEP II has been ordered by the U.S. Bureau of Reclamation to develop a water conservation offset program (WCOP) to offset its groundwater use. As part of this water conservation effort, the WCOP would retire or fallow lands on a rotational basis within the Palo Verde Irrigation District's (PVID) service area that are, or have been, irrigated within the past five years. These lands also would be situated in the Palo Verde Mesa and/or the Palo Verde Valley. If the fallowing option is chosen, based on a consumptive water use volume of 4.2 acre-feet per acre per year and BEP II's proposed

usage of 3,300 acre-feet of water per year, the WCOP would idle about 786 acres of irrigated farmland every year for the life of the project.

PUBLIC AND AGENCY COORDINATION

Extensive coordination has occurred with the numerous local, state and federal agencies that have an interest in the project. Particularly, Energy Commission staff has worked with the City of Blythe, Riverside County Airport Land Use Commission (ALUC), California Department of Transportation (Caltrans) Aeronautics Division, Federal Aviation Administration, U.S. Department of the Interior, Bureau of Land Management, California Independent System Operator (Cal-ISO), Western, Southern California Edison (SCE), Palo Verde Irrigation District (PVID), Colorado River Board of California, Mojave Desert Air Quality Management District (MDAQMD), California Air Resources Board, U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, and California Department of Fish and Game to identify and resolve issues of concern.

The Preliminary Staff Assessment (PSA) was published on November 14, 2003. The PSA concluded that there was insufficient information for staff to determine if the project would conform with all applicable LORS, and whether the project's potential impacts on public health and safety, the environment, and the regional transmission system would be adequately mitigated. Substantial additional information for Air Quality, Biology, Cultural Resources, Land Use, Socioeconomics, Traffic and Transportation, Transmission System Engineering (TSE), Worker Safety and Fire Protection, and Soil and Water Resources was specifically identified as necessary to complete the analysis, prepare the FSA and make the necessary recommendations.

In its Scheduling Order of February 4, 2004, the Committee determined that there were several topics in the PSA for which the applicant needed to supply data for Energy Commission staff to have sufficient information to complete and file its FSA. The order determined that the information should be submitted by March 22, 2004. The specified information was not provided to the Energy Commission by the required date. Energy Commission staff requested and was granted a day-for-day extension in the schedule until all outstanding information was submitted and complete.

The applicant submitted the last remaining information from the Committee Order on January 20, 2005. Energy Commission staff conducted PSA Workshops in Blythe on January 26, 2005, and in Sacramento on February 15, 2005. Written PSA comments received from local, state, and federal agencies, and concerned citizens, along with staff's response to each, have been included in this FSA. Written and verbal comments were carefully considered and incorporated into the analysis where appropriate.

JOINT CEQA/NEPA PROCESS

Caithness Blythe II has filed a request with Western to interconnect the proposed BEP II power plant at the Buck Boulevard Substation. Western proposes modifications at its Buck Boulevard Substation to accommodate the interconnection of the proposed power plant. The request to interconnect to Western's power system triggers a Federal National Environmental Policy Act (NEPA) review process in addition to the Energy

Commission's CEQA permitting process. Western also is the lead federal agency for compliance with the National Historic Preservation and Endangered Species Acts.

SUMMARY OF STAFF'S TECHNICAL CONCLUSIONS

Energy Commission staff has serious concerns that BEP II, as currently located and designed, would have potentially significant adverse impacts to Biological Resources, Water Resources, Land Use, and Traffic and Transportation. Each of these impacts have some degree of linkage to each other. They are summarized below along with the relationship between them.

Staff expects that BEP II's proposed evaporation pond would have high, toxic levels of selenium and sodium in its water similar to the levels recently measured in BEP I's existing ponds, which would be a significant direct impact for **Biological Resources**. Birds and wildlife would be drawn to the pond's water and adversely affected. This issue also affects the **Water Resources** area since the project's current design involves turbine cooling water being released to a new evaporation pond and one that would be shared with BEP I. Staff believes that these potential impacts can be mitigated by eliminating the evaporation pond and using zero liquid discharge technology to dispose of cooling wastewater. This approach would also reduce the incidence of birds being attracted to the site, which presents a nuisance and a potential hazard to safe aviation operations at the nearby Blythe Airport.

A significant direct impact to **Water Resources** is likely because of local groundwater contamination resulting from the proposed project's deep wells that would supply water for turbine cooling. This would adversely affect residents of the surrounding Palo Verde Mesa area who are dependent on domestic wells for their drinking water supplies. Staff believes that this issue can be mitigated by either using dry cooling technology or wet cooling using low quality irrigation return water in conjunction with a WCOP that can be quantified and verified.

Staff has also identified a significant cumulative impact from the project's consumption of an already very limited supply of Colorado River water. The proposed wells and related groundwater basin would be hydrologically connected to the Colorado River, as the BEP I wells currently are. This issue can be mitigated by either using dry cooling technology or through development of a WCOP.

Staff is also concerned that the proposed project conflicts with some State policies regarding use of fresh water for industrial cooling purposes as a wasteful practice. Furthermore, the Energy Commission's 2003 Integrated Energy Policy Report states that fresh water should be the last choice when feasible and economical options such as recycled water or technology alternatives such as dry cooling are available. Staff has determined that recycled water is not sufficiently available, but that dry cooling is feasible and economical for BEP II, and that irrigation return water coupled with a WCOP is also feasible. Staff has recommended that either one be used to avoid a wasteful use of fresh water and inconsistency with State policy.

The Riverside County Airport Land Use Commission (ALUC) has determined that the proposed use of the BEP II site is not consistent with the Comprehensive Land Use Plan (CLUP) for the Blythe Airport. This State mandated Plan was formulated to ensure that surrounding land uses are compatible with airport operations. The ALUC's determination presents a LORS conformance problem, which is a potentially significant **Land Use** impact. Staff has not identified any mitigation for this impact.

BEP II's inherent need for turbine cooling at the proposed site will result in thermal and visible plumes with a potentially significant impact on aviation related **Traffic and Transportation** as it relates to aviation safety. Based upon pilot complaints and subsequent investigation associated with BEP I, staff expects that under certain weather conditions the plumes will create air turbulence and adversely affect pilots approaching the nearby Blythe Airport, which is approximately .75 mile from the BEP II site. Energy Commission staff, as well as the Riverside ALUC and the Caltrans Aeronautics Division staff, are concerned with the potential for direct impacts on aircraft safety caused by BEP II plumes, and the cumulative effects of the BEP II facilities' plumes when combined with those from the existing BEP I facility. A safety hazard for pilots, particularly those who are inexperienced, will result from facility operation whether wet cooling is used as proposed, or whether dry cooling is employed as recommended by staff. Staff has not been able to identify any feasible mitigation for this impact, and therefore has concluded that the BEP II should not be approved at the proposed site due to unavoidable conflicts with the safety of pilots using the Blythe Airport.

Staff's **Traffic and Transportation** conclusion regarding the conflict with the proposed site and the ongoing Blythe Airport operations, lead to an **Alternatives** evaluation of potential impacts at alternative sites, along with other technology options and the No Project Alternative. Staff's recommendation of using dry cooling or irrigation return water in conjunction with a WCOP was applied to each alternative site option considered in the Blythe area due to the groundwater hydrologic connection to the Colorado River system.

In addition to the potentially significant impacts discussed above, staff has insufficient and outdated information in the **Transmission System Engineering** area. The existing transmission studies are inaccurate and incomplete. Staff will be petitioning the Committee to compel the applicant to provide the complete information needed. The applicant is relying on the 2002-03 Blythe Area Regional Transmission (BART) Study instead of a System Impact Study for the project's transmission interconnection. The BART study is not based on a current project description, and staff has substantial concerns about its validity. The FSA identifies the lack of System Impact Studies and the lack of consideration of pending projects in the CA ISO and Western transmission planning queue (e.g., Southern California Edison's proposed Devers-Palo Verde No.2 500 kV Project and the Blythe I Energy Project Transmission Line modification plan). The applicant has proposed that BEP II connect with Western's transmission grid via the Imperial Irrigation District's proposed Desert Southwest Transmission Project. However, staff has substantial concerns about the viability and timing of this transmission project, since it is unknown when the Final Draft Environmental Impact Statement/ Draft Environmental Impact Report will be completed and released.

SUMMARY OF SIGNIFICANT AND UNAVOIDABLE IMPACTS

Staff believes that as currently proposed, the project will not comply with all applicable laws, ordinances, regulations, and standards (LORS), and that significant adverse direct, indirect, and cumulative impacts will occur. Significant issues in key technical areas are summarized below. For a more detailed review of potential impacts, see staff's technical analyses in the FSA.

Technical Area	Complies with LORS	Impacts Mitigated
Air Quality	Yes	Yes
Biological Resources	**No**	**No - Staff is recommending the applicant redesign project to a zero-liquid to solids technology**
Cultural Resources	Yes	Yes
Efficiency	Yes	Yes
Facility Design	Yes	Yes
Geology & Paleontology	Yes	Yes
Hazardous Materials	Yes	Yes
Land Use	**No**	**No – Conflict with Blythe Airport Comprehensive Land Use Plan**
Noise	Yes	Yes
Public Health	Yes	Yes
Reliability	Yes	Yes
Socioeconomic Resources	Yes	Yes
Soil & Water Resources	**No**	**No-BEP II has a significant direct and cumulative impact on groundwater quality, cumulative impacts on depleted Colorado River water supply and conflicts with State water policies.** **Use of agricultural irrigation return water and dry cooling would mitigate impacts to water, but would affect adjacent airport safety**
Traffic & Transportation	**No – Insufficient information**	**No- direct and cumulative impacts to airport safety**
Transmission Line Safety/Nuisance	Yes	Yes
Transmission System Engineering	**No– Insufficient information**	**No- project description is outdated, and provides insufficient information to determine environmental impacts of facilities and LORS conformance**
Visual Resources	Yes	Yes
Waste Management	Yes	Yes
Worker Safety and Fire Protection	Yes	Yes

ENVIRONMENTAL JUSTICE

Energy Commission staff has determined the potentially affected environmental justice region to be an area within a six-mile radius of the proposed BEP II site. The population within this area totals 12,170. The minority population within this area totals 7,216, or 59.29 percent of the total population. Because the screening analysis shows a greater than 50 percent minority population within the six-mile radius, staff considered an Environmental Justice screening as part of its environmental analysis. Staff also determined that 20.1 percent of the population is below the poverty level.
BEP II is located about two miles from Mesa Verde/Nicholls Warm Springs, a small, unincorporated residential and largely Spanish-speaking community in the Palo Verde Mesa. Residents of this community and the surrounding unincorporated area rely on private wells to pump groundwater for domestic and agricultural use.

Based on the **Soil and Water Resources** analysis, staff concludes that the proposed project could cause a disproportionate significant impact to a minority population if it is approved to use groundwater for cooling. This involves the potential significant direct impact to the community of Mesa Verde/Nicholls Warm Springs and surrounding private well users from the project's groundwater pumping. The proposed pumping would likely cause the upwelling or transport of groundwater with higher concentrations of naturally occurring minerals, degrading the aquifer's water quality.

The FSA concludes that the potential direct impact to local groundwater from BEP II would be mitigated to a less than significant level if the applicant redesigns the project. Specifically, this involves one of two options: 1) redesign BEP II to a dry cooling system; or 2) require BEP II to purchase low quality agricultural drain return water from PVID and implement a verifiably effective WCOP to mitigate the cumulative impact to the regional groundwater system. Implementation of either option would mitigate the potential environmental impact to groundwater as well as eliminate the disproportionate impact to a minority population. However, staff is not recommending approval of the BEP II project at the proposed site due to aviation safety concerns.

CONCLUSION AND RECOMMENDATION

Staff cannot recommend approval of the BEP II as proposed by the applicant at the current location. This recommendation results from the significant, unavoidable aviation safety impacts to pilots using the Blythe Airport and the inconsistency with the Airport's CLUP. Furthermore, staff is recommending that before this project can be approved, the applicant needs to:

- provide the appropriate Transmission System Engineering information;
- redesign the project to utilize a zero liquid discharge system; and
- use dry cooling or irrigation return water with a WCOP if an alternative site in the Blythe region is selected.

After evidentiary hearings, if the Commission decides to recommend approval of the project, staff has proposed conditions of certification to ensure that the facility is

constructed and operated in a safe and reliable manner and potential impacts are mitigated to a level of insignificance. Each technical area in the FSA includes a discussion of the project and the existing environmental setting; the project's conformance with laws, ordinances, regulations and standards (LORS) and whether the facility can be constructed and operated safely and reliably; project related direct and cumulative impacts; the environmental consequences of the project using the proposed mitigation measures; response to comments on the PSA, conclusions and recommendations; and any proposed conditions of certification under which the project should be constructed and operated.

Based on the significant impacts discussed above and other concerns, four alternative power plant sites were considered, including a Blythe Airport Site, Interstate 10 (I-10) Site, and South of Blythe Site, and one site adjacent to the Devers Substation north of Palm Springs. (Please refer to **Alternatives** Figures 1 and 2) Overall, the four site alternatives considered offer some advantages and disadvantages in comparison to the proposed project. With the exception of aviation safety impacts, three sites in the Blythe area have the same challenges as the proposed project with respect to water use and wet cooling; biological impacts from open evaporation ponds; and the same need for new transmission studies.

Of the alternatives considered, the I-10 Site provides a feasible alternative to the BEP II project. Because this site is not near the airport, dry cooling or wet cooling using irrigation return water together with a WCOP could be used and would mitigate the project's impacts to water resources. A zero liquid discharge system would eliminate impacts to migratory birds. Although there are potential noise and visual resource impacts associated with this site, these impacts are likely mitigated to a less than significant level. The I-10 site is on prime farmland soils, so mitigation would also be required to compensate for the loss of farmland.

BLYTHE ENERGY PROJECT PHASE II
(02-AFC-1)
FINAL STAFF ASSESSMENT

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INTRODUCTION

Testimony of William Pfanner

This is the California Energy Commission's Final Staff Assessment for the proposed Blythe Energy Project Phase II (BEP II).

Caithness Blythe II, LLC, filed an Application For Certification (AFC) with the California Energy Commission on February 19, 2002. The project AFC was amended in May 2002 to relocate the BEP II structures to the adjacent parcel and again in July of 2002 to reconfigure the evaporation ponds. On April 21, 2004, the applicant filed a Revision to Section 2.0 (Project Description) of the AFC to make minor changes to the project description and modify the description of the electrical interconnection system.

The proposed project would be located next to the Blythe Energy Project (BEP I) that was approved by the Energy Commission in 2001 and began operation in July 2003. BEP I is owned and operated by Florida Power and Light, which is a completely separate entity from the applicant for BEP II, Caithness Blythe II, LLC.

ORGANIZATION OF THE FINAL STAFF ASSESSMENT

This **INTRODUCTION** section explains:

- the project's chronology;
- the purpose of the FSA;
- the differences between the Preliminary Staff Assessment (PSA) and the FSA;
- the relationship to the Commission's facility siting process;
- the public and agency coordination process; and
- staff's approach for addressing potential environmental justice issues and the related public outreach process.

The **ENVIRONMENTAL** and **ENGINEERING** evaluations of the proposed project follow the **PROJECT DESCRIPTION**. In the **ENVIRONMENTAL** analyses, the project's environmental setting is described, environmental impacts are identified and their significance assessed, and the project's compliance with applicable laws, ordinances, regulations and standards (LORS) are reviewed. The mitigation measures proposed by the applicant are reviewed for adequacy and conformance with applicable laws; if any remaining unmitigated impacts are identified, staff proposes additional mitigation measures and/or project alternatives. Staff's conclusions and recommendations are discussed, and proposed conditions of certification are included, if applicable. In the **ENGINEERING** analyses, the project is evaluated in each technical area with respect to applicable LORS and performance objectives. Each technical section ends with a discussion of conclusions and recommendations. Proposed conditions of certification are included, if applicable. The **SOIL AND WATER RESOURCES** Technical Report will be published in May 2005, providing the background information to support the Soil and Water Resources Summary contained in the FSA.

PROJECT CHRONOLOGY

The PSA was published in November 2003. The PSA stated that there was insufficient information for staff to conclude the project would conform with all applicable LORS, and whether the project's potential impacts on public health and safety, the environment, and transmission system will be adequately mitigated. Substantial additional information for Air Quality, Biology, Cultural Resources, Land Use, Socioeconomics, Traffic and Transportation, Transmission System Engineering (TSE), Worker Safety and Fire Protection, and Water and Soil Resources was identified as necessary to complete the FSA.

Considering the number of outstanding issues, staff recommended that the PSA be circulated for review and comment, and that the Committee hold a Status Conference to allow the applicant to identify when the outstanding information would be provided and the Committee to determine the project schedule.

The Status Conference on the PSA was held on January 22, 2004, resulting in the Committee's recommendations on what information would be required by the applicant and the project schedule for preparing the FSA.

In its Scheduling Order dated February 4, 2004, the Committee determined that there were several topics in the PSA for which the applicant needed to supply data for Energy Commission staff to have sufficient information to complete and file the FSA. The Order determined that the information should be submitted by March 22, 2004. The specified information was not provided to the Energy Commission by the required date. Energy Commission staff requested and was granted a day-for-day extension in the schedule until all outstanding information was submitted and complete.

In its Status Report to the Committee of July 9, 2004, staff identified serious concerns that the project, as currently designed, could have significant unmitigated adverse impacts to Water Resources, Traffic and Transportation, and Transmission System Engineering (TSE).

The applicant submitted the last remaining information from the Committee Order on January 20, 2005. Energy Commission staff conducted PSA Workshops in Blythe on January 26, 2005 and in Sacramento on February 15, 2005. In the Status Report of February 14, 2005, staff noted that extensive time had elapsed since the preparation of the PSA and that the applicant may have lost its original place in the Western and the California Independent System Operator (CA ISO) generation/transmission queue in relation to the transmission projects currently proposed in the region.

This Final Staff Assessment (FSA) is the Energy Commission staff's independent analysis of the BEP II project. The FSA describes and analyzes the following:

- the proposed project;
- the existing environment;
- whether the facilities can be constructed and operated safely and reliably in accordance with applicable 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, and interested agencies which may lessen or eliminate potential impacts;
- project alternatives; and
- the proposed conditions under which the project should be constructed and operated, if it is certified.

The analyses contained in this FSA are based upon information from the: 1) AFC, 2) subsequent AFC amendments, 3) responses to data requests, 4) supplementary information from local and state agencies and interested individuals, 5) existing documents and publications, 6) independent field studies and research, and 7) comments at workshops. 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 FSA presents conclusions and proposed conditions that apply to the design, construction, operation and closure of the proposed facility.

The Energy Commission staff's analyses were prepared in accordance with Public Resources Code section 25500 et seq. and Title 20, California Code of Regulation section 1701 et seq., and the California Environmental Quality Act (CEQA) (Pub. Resources Code, §21000 et seq.).

DIFFERENCES BETWEEN THE PRELIMINARY AND FINAL STAFF ASSESSMENT

During the period after the publishing of the PSA, staff has conferred with the applicant, citizens, responsible and trustee agencies, and conducted workshops to discuss its findings, proposed mitigation, and proposed compliance-monitoring requirements. Based on these communications, workshops and written comments, staff has refined its analysis and finalized conditions of certification for inclusion in this FSA. The principal differences between the PSA and Final FSA are as follows:

AIR QUALITY

Outstanding Data Identified in the PSA

The PSA identified that a Final Determination of Compliance (FDOC) for the Mojave Desert Air Quality Management District (MDAQMD) was needed. It also stated that a wind erosion control plan for the Water Conservation Offset Program (WCOP) must be submitted and reviewed and approved by the Federal Natural Resources Conservation Service (NRCS) prior to the completion of the FSA. Without implementation of the appropriate soil conservation practices on the fallowed WCOP lands, the PSA concluded that there may need to be additional measures to control wind erosion and any associated particulate emissions.

Discussion

The applicant provided the required Air Quality information, and the FSA has incorporated this information with no significant changes from the conclusions of the PSA.

BIOLOGICAL RESOURCES

Outstanding Data Identified in the PSA

The PSA concluded that a Biological Assessment (BA) for an at risk species, the western burrowing owl, must be accepted as complete by the U.S. Fish and Wildlife Service (USFWS) and that a mitigation and monitoring plan for the burrowing owl must be proposed that is acceptable to California Department of Fish and Game (CDFG).

Discussion

The applicant provided the information listed above. Staff incorporated the new information into the FSA and created a new Condition **BIO-10** related to burrowing owls.

Two new issues have arisen since the PSA was published: 1) a February 2005 finding of high selenium and sodium levels in the BEP I evaporation ponds with the USFWS concluding that migratory birds are negatively affected. Similar impacts would be expected with the BEP II evaporation pond; and 2) the BEP I ponds are an "attractive nuisance" for the nearby Blythe Airport since migratory birds are drawn to the water, with similar implications for the BEP II pond. Staff discusses this issue in the **Executive Summary** and the **Biological Resources** section of the FSA.

CULTURAL RESOURCES

Outstanding Data Identified in the PSA

The PSA identified that the applicant and staff must complete consultation with Native Americans to identify and evaluate resources that could be impacted by the project, and the City of Blythe must determine through their planning process whether there would be ground-disturbing activities required outside of the project site.

Discussion

The requested information was provided to staff and incorporated into the FSA. Minor changes were made to the FSA's Cultural Resource Conditions of Certification.

LAND USE

Outstanding Data Identified in the PSA

The PSA requested the applicant to provide a full description of the proposed Water Conservation Offset Program (WCOP) including a parcel by parcel identification of farmland classifications, irrigation status, permanently retired parcels, and Williamson Act status.

The PSA also required that Caithness provide a recommendation from the City of Blythe regarding a height variance and site plan application.

Further, the PSA identified that the Airport Land Use Commission (ALUC) had determined that the project was inconsistent with the County Land Use Plan (CLUP), while recommending conditions if the Energy Commission decides to approve the project. The City had not submitted its analysis and recommendation regarding the ALUC's determination, which the PSA identified as necessary for the completion of the FSA.

Discussion

In the Committee Scheduling Order of February 4, 2004, the Committee determined that the applicant would not be required to supply additional information on the WCOP and that staff would prepare its analysis based on the general information the applicant had provided in the AFC. Therefore, the FSA's Land Use section contains staff's WCOP analysis with a new condition, **LAND-3** added.

The PSA concluded that the project was consistent with the City's General Plan and generally consistent with the City's zoning; however, the project exceeded the City's 34-foot height restriction in the Heavy Industrial Zone. The FSA notes that the City's Planning Department approved a height variance for the project.

The City of Blythe's analysis and recommendation are discussed in the Land Use and Traffic and Transportation sections of the FSA, with new condition **LAND-4** added.

SOCIOECONOMICS

Outstanding Data Identified in the PSA

The PSA requested a complete description of the proposed fallowing of croplands associated with the WCOP. This needed to include details on the exact location of acreage being fallowed, such as township and range and number of acres and type of crop to be fallowed.

Discussion

As noted above, in the Committee's Scheduling Order of February 4, 2004, it was determined that the applicant would not be required to supply additional information on the WCOP. The Committee directed staff to prepare its analysis based on the general information the applicant had provided in the AFC, which is contained in the Socioeconomic section of the FSA, with a new Condition **SOCIO-2** added.

TRAFFIC AND TRANSPORTATION

Outstanding Data Identified in the PSA

The PSA concluded that additional analysis was needed to assess the impact of BEP II on aviation traffic safety. The PSA identified that this analysis would be based on studies of the potential impact of visual and thermal plumes on Blythe Airport operations and will include assessment of the cumulative impact of BEP I and BEP II.

The PSA also stated that Caithness may need to apply to the FAA for the evaluation of transmission towers that may be taller than the HRSG stacks.

The City's recent renovation of Hobsonway does not allow for oversize and overweight loads to be transported on Hobsonway from the railroad offloading point near Commercial Street. Description of an alternative route for oversize and overweight loads that avoids use of Hobsonway was needed.

Discussion

The outstanding data was received and incorporated into the Traffic and Transportation section of the FSA.

TRANSMISSION SYSTEM ENGINEERING

Outstanding Data Identified in the PSA

The PSA concluded that staff had insufficient information to complete a full analysis of the BEP II applicant's proposal for transmission interconnection.

In April of 2004 staff received the applicant's comments on the PSA's Transmission System Engineering section. The applicant recommended a condition of certification that would ostensibly allow the project to go forward without information on the interconnection configuration.

Discussion

Staff's Transmission System Engineering section discusses the above proposed condition and the reason why staff believes that this technical area still has insufficient information for project evaluation and determination of LORS compliance.

SOIL AND WATER RESOURCES

Outstanding Data Identified in the PSA

The PSA concluded that the following additional information was required to prepare the FSA:

- A full description of the implementation, verification and monitoring of the proposed Water Conservation Offset Program (WCOP);
- An Amendment to the AFC changing the project to dry cooling;
- Identification of discharge wastewater from the BEP II facility to the proposed evaporation pond, including corrected evaporation pond calculations and submit this information to the Regional Water Quality Control Board (RWQCB);
- Draft waste discharge requirements (WDRs) for the evaporation ponds;
- Quantification of the amount of auxiliary firing and reflect the associated water use in revised heat and water balances;

- Revised heat and water balances to reflect the type of inlet cooling that will be used at the plant;
- Revised design calculations for the stormwater retention basin that demonstrate that the proposed retention basin can contain the runoff produced by a 100-year event and would meet the City of Blythe's freeboard requirements;
- A revised retention basin design that includes an emergency spillway or outlet structure to safely route potential overflows away from the containment berm are needed; and
- A full report on the 2002 groundwater quality sampling of BEP I production wells including the results that did not exceed the primary or secondary drinking water standards.

Discussion

The applicant has elected to pursue approval of a project with a wet cooling system, with a Water Conservation Offset Program (WCOP) that would entail rotational fallowing or retirement of irrigated farmland in the area.

In its Scheduling Order of February 4, 2004, the Committee determined that the applicant would not be required to supply additional information on the WCOP and that staff would prepare its analysis based on the general information the applicant had provided in the AFC.

Other than not changing to a dry cooling system and not providing detailed information on the WCOP, the applicant provided the other information requests in the PSA, which has been incorporated into the FSA.

WORKER SAFETY AND FIRE PROTECTION

Outstanding Data Identified in the PSA

Prior to the issuance of the FSA, the applicant and the City of Blythe Fire Department needed to provide staff with specific information for staff to conduct a thorough analysis and make a determination regarding impacts to local emergency response services.

Discussion

The requested information was provided, and the subsequent analysis resulted in no changes needing to be made in the FSA from the PSA section's Conditions of Certification.

ENVIRONMENTAL JUSTICE

Outstanding Data Identified in the PSA

For staff to complete the environmental justice analysis, the applicant needed to provide full details on the proposed fallowing of croplands associated with the WCOP including the exact location of acreage being fallowed (such as township and range) the

number of acres and type of crop to be fallowed, and number of workers associated with the crop and acreage.

Discussion

As noted above, in the Committee's Scheduling Order of February 4, 2004, it was determined that the applicant would not be required to supply additional information on the WCOP and that staff would prepare its analysis based on the general information the applicant provided in the AFC.

The Committee directed staff to prepare its analysis based on the general information the applicant had provided in the AFC, which is contained in the Socioeconomic section of the FSA, with a new Condition **SOCIO 2** added.

ENERGY COMMISSION SITING PROCESS

The California Energy Commission has the exclusive authority to certify the construction, modification 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, §25500). The Energy Commission must review power plant AFCs to assess potential environmental impacts including potential impacts to public health and safety, potential measures to mitigate those impacts (Pub. Resources Code, §25519), and compliance with applicable governmental laws or standards (Pub. Resources Code, §25523 (d)).

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

Staff conducts its environmental analysis in accordance with the requirements of the California Environmental Quality Act (CEQA). No additional Environmental Impact Report (EIR) is required because the Energy Commission's site certification program has been certified by the Resources Agency as meeting all requirements of a certified regulatory program (Pub. Resources Code, §21080.5 and Cal. Code Regs., tit. 14, §15251 (k)). Where it is appropriate, the FSA incorporates comments received from agencies, the public and parties to the siting case, and comments made at public workshops.

Staff will provide an FSA comment period to resolve issues between the parties and to narrow the scope of adjudicated issues in the evidentiary hearings.

The FSA is only one piece of evidence that will be considered by the Committee (two Commissioners who have been assigned to this project) in reaching a decision on whether or not to recommend that the full 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 also provides a forum for the Committee to receive comments from the public and other governmental agencies.

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

PUBLIC AND AGENCY COORDINATION

Publicly noticed workshops have been held in the City of Blythe, Ontario and Sacramento. Topics discussed included: air quality, biology, cultural resources, geology, land use, noise, socioeconomics, traffic and transportation, transmission system engineering, visual resources, and soil and water.

In addition to these workshops, extensive coordination has occurred with the numerous local, state and federal agencies (listed in the Executive Summary) that have an interest in the project.

ENVIRONMENTAL JUSTICE

Executive Order 12898, "Federal Actions to address Environmental Justice in Minority Populations and Low-Income Populations," focuses federal attention on the environment and human health conditions of minority communities and calls on federal agencies to achieve environmental justice as part of this mission. The order requires the U.S. Environmental Protection Agency (USEPA) and all other federal agencies (as well as state agencies receiving federal funds) to develop strategies to address this issue. The agencies are required to identify and address any disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and/or low-income populations.

For all siting cases, Energy Commission staff conducts an environmental justice screening analysis in accordance with the "Final Guidance for Incorporating Environmental Justice Concerns in USEPA's National Environmental Policy Act (NEPA) Compliance Analysis" dated April 1998. The purpose of the screening analysis is to determine whether there exists a minority or low-income population within the potentially affected area of the proposed site.

California statute, section 65040.12 (c) of the Government Code, defines "environmental justice" to mean "fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies." In light of the progress made by federal environmental agencies on environmental justice, the Energy Commission has examined federal guidelines pursuant to its desire to follow environmental justice principles for the environmental review of this project.

The U. S. Environmental Protection Agency (EPA) issued draft guidance for implementing Executive Order 12898, which was signed by President Clinton in 1998 and relates to considering environmental justice, in the context of the National Environmental Policy Act (NEPA), 42 U.S.C. section 4321 et seq. This guidance is entitled "Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analysis" (dated April 1998). In addition, the Council on Environmental Quality has developed additional guidance entitled "Environmental Justice Guidance Under the National Environmental Policy Act" (dated December 1997).

The steps recommended by these guidance documents to assure compliance with the Executive Order are: (1) outreach and involvement; (2) a screening-level analysis to determine the existence of a minority or low-income population; and (3) if warranted, a detailed examination of the distribution of impacts on segments of the population. Though the Federal Executive Order and guidance are not binding on the Energy Commission, staff finds these recommendations helpful for implementing this environmental justice analysis. Staff has followed each of the above steps for the following 11 sections in the FSA: Air Quality, Hazardous Materials, Land Use, Noise, Public Health, Socioeconomics, Soils and Water, Traffic and Transportation, Transmission Line Safety/Nuisance, Visual Resources, and Waste Management. The discussion of staff's review of environmental justice is contained in each of the above sections.

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. 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. People of color 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.

The EPA requires local air districts to perform an environmental justice analysis for Prevention of Significant Deterioration permits. As the lead agency for reviewing applications to build new thermal electric generation facilities greater than 50 megawatts, the Energy Commission performs an environmental justice analysis in part to assist the local air districts.

ENVIRONMENTAL JUSTICE OUTREACH

The Energy Commission's environmental justice outreach program is facilitated by the Public Advisers Office (PAO). This is an ongoing process that to date has involved the following.

Libraries: On July 18, 2002, the PAO sent the Blythe II AFC to the Parker, Arizona Public Library; the Riverside Main Library in Riverside County; the Palo Verde Valley District Library in Blythe, and the Brawley Public Library in Imperial County. To assist the public in locating the AFC, the PAO prepared a poster to announce the project with key contact information. Along with the library AFC, the PAO sent 25 copies of the one-page bilingual project description and the poster. The librarians were asked to place the posters and project descriptions in areas accessible to the public.

Schools: July 30, 2002, the PAO sent 20 bilingual project descriptions and a poster to both the Palo Verde Unified School District and the Palo Verde Community College District.

Chamber of Commerce: The PAO also sent 3 posters and 20 bilingual project descriptions to the Palo Verde/Riverside County Chamber of Commerce. The Chamber of Commerce was asked to place the posters on various town informational bulletin boards and place the project descriptions in areas accessible to the public.

Newspapers: The PAO prepared 4,500 bilingual newspaper inserts announcing the time, date and location of the Informational Hearing and Site Visit. The inserts were sent to the "Palo Verde Times" newspaper for distribution in their September 4, 2002, edition.

Further Outreach: In addition, the PAO sent bilingual notice of the September 9, 2002 Informational Hearing and Site Visit to the Palo Verde/Riverside Chamber of Commerce; the Palo Verde Community College District; the Palo Verde Unified School District; the Brawley Public Library; the Riverside Main Library; the Parker Arizona Public Library; and the Palo Verde Valley District Library for distribution

Notices: Notices of the "Informational Hearing and Site Visit," the "Data Request and Issue Resolution Workshop" held on September 9, 2002, the Status Conference on the PSA held on January 22, 2004, the PSA Workshops in Blythe on January 26, 2005, and the PSA Workshop in Sacramento on February 15, 2005 were mailed to the General Public, Property Owners, Agency lists and the parties on the BEP II Proof of Service list. The Commission's list server also sent the notice to all subscribers on the BEP II electronic notice lists. The Notice of Availablility for the FSA was published in both English and Spanish.

Meetings: The AFC review process involves hearings and workshops to receive comments from the public. The Public Adviser attended the Informational Hearing and Site Visit in Blythe as well as the Issue Identification Workshop on September 9, 2002.

For the workshops dated September 10, 2002, and November 5 and 6, 2002, the PAO provided copies of the project description, status reports and general information on how to obtain assistance from the PAO. The Public Adviser's staff also participated in the Status Conference on the PSA on January 22, 2004, the PSA Workshops in Blythe on January 26, 2005, and the PSA Workshop in Sacramento on February 15, 2005.

PROJECT DESCRIPTION

Testimony of William Pfanner

INTRODUCTION

The Blythe Energy Project Phase II Application for Certification (AFC) was filed by the applicant Caithness Blythe II on February 19, 2002. The project AFC was amended in May 2002 to relocate the BEP II structures to the adjacent parcel and again in July of 2002 to reconfigure the evaporation ponds. On April 21, 2004, the applicant filed a Revision to Section 2.0 (Project Description) of the AFC to make minor changes to the project description and modify the description of the electrical interconnection system.

As defined in the AFC, the Revised AFC, the Revision to Section 2.0 of the Blythe Energy Project Phase II AFC and responses to Data Requests, the Blythe Energy Project Phase II (hereinafter referred to as BEP II) is a nominally rated 520 megawatt (MW) combined-cycle power plant. The proposed project is adjacent to the approved and operating Blythe Energy Project (BEP I) described in 99-AFC-8, on file with the California Energy Commission (Energy Commission). BEP I is owned and operated by Florida Power and Light, whereas BEP II is proposing separate generation units, with some facilities that may be shared with BEP I. BEP II consists of two Siemens Westinghouse V84.3a 170 MW combustion turbine generators (CTGs), one 180 MW steam turbine generator and supporting equipment.

BEP II is adjacent to the west side of the BEP I site boundary on the Expansion Site approved by the Energy Commission as an amendment to BEP I (See BEP I Petition for Amendment I-B, dated November 23, 2001). BEP II may utilize some existing facilities at the BEP I site including the BEP I Control/Administration and Maintenance Buildings and the surface water runoff retention basin. Other BEP I facilities that may be expanded to serve BEP II include the groundwater supply, fire protection facilities and site access roads Natural gas will be supplied to the BEP II plant by the natural gas pipeline constructed as part of BEP I.

As described in the Revision to Section 2.0 of the Blythe Energy Project Phase II AFC (BEP II 2004d.), BEP II will be electrically interconnected to the Buck Boulevard Substation, located in the northeastern corner of the BEP I site. The federal Western Area Power Administration (Western) constructed the Buck Boulevard Substation as part of BEP I, with additional facilities to be provided by Western for connection to BEP II. The Buck Boulevard Substation connects to the Western-owned Blythe Substation. As defined in the Revision to Section 2.0 of the Blythe Energy Project Phase II AFC (BEP II 2004d.) which was filed in April 2004, a 500 kV connection to the Desert Southwest Transmission Project (DWSTP) will be provided. The Blythe Substation interconnects five existing 161 kV regional transmission lines. Three of the transmission lines are owned by Western, one by Imperial Irrigation District (IID), and the other by Southern California Edison (SCE).

Water to operate the facility will be supplied by two (2) additional groundwater wells, each having the capacity to pump up to 3,000 gallons per minute (gpm). Supply and

wastewater treatment systems similar to those constructed as part of BEP I will be provided. An additional wastewater evaporation pond will be provided for BEP II.

GENERATION FACILITY DESCRIPTION, DESIGN AND OPERATION

The BEP II site is located within the City of Blythe, approximately five miles west of the center of the City. **Figure 1** provides a map of the regional setting. **Figure 2** provides an aerial photo of the BEP I and BEP II sites and their immediate vicinity. **Figure 3** illustrates the site plan and layout for BEP I and BEP II. The original BEP I site boundary included 76 acres. Blythe Energy secured the rights to use the adjacent 76 acres (2 parcels) from Riverside Power, LLC, a subsidiary of Caithness Energy on December 30th, 2001. Subsequently, BEP I amended its license to expand the BEP I site boundary to include the adjacent 76 acres, increasing the BEP I parcel size to 152 acres. The BEP II power facilities would be located on the western 76 acres of the 152 acre BEP I site.

The project site is located east of the Blythe Airport, which is currently owned by Riverside County and operated by the City of Blythe. The project site is on an intermediate plateau, about 70 feet in elevation above and west of the Colorado River Valley and the City of Blythe and about 60 feet below the elevation and east of the Blythe Airport. The topography of the project site is flat. The BEP sites (BEP I and II) are bounded on the south by Hobsonway and on the east by Buck Boulevard. Hobsonway is a paved highway running east/west parallel to and one-quarter mile north of Interstate 10 (I-10). Buck Boulevard has been paved as part of BEP I. Buck Boulevard runs along the eastern side of the BEP I property line and runs north from Hobsonway. The north boundary of the site is Riverside Avenue which is paved only along the frontage of BEP I. The rest is an unpaved easement dedicated for extending Riverside Avenue.

Some of the additional facilities required in the Buck Boulevard Substation for BEP II Western has already evaluated and approved as part of its BEP I Facility Study. However, to facilitate the 500 kilovolt (kV) single circuit from the BEP II Integration switchyard, the Buck Boulevard Substation would be expanded to include three 500 kV switch bus and a transformer.

The applicant has stated that BEP II would connect to the Buck Boulevard Substation, which in turn would tie in to a proposed approximately 118-mile long, 500 kV single circuit transmission line connecting to Devers Substation north of Palm Springs, California. The Imperial Irrigation District (IID) has proposed this new transmission line, referred to as the Desert Southwest Transmission Project (DSWTP). See the **Transmission System Engineering** section in the FSA for a detailed discussion. The DSWTP is not under the permitting jurisdiction of the Energy Commission and is being evaluated by the U.S Department of the Interior Bureau of Land Management (BLM) under the Desert Southwest Transmission Project Environmental Impact Statement (EIS)/Environmental Impact Report (EIR) proceedings. A Draft EIS/EIR has been published for the DSWTP project (April 2003), but to date, no Final EIS/EIR has been published.

Process Description

As defined in the AFC and supplemental filings, the power plant will consist of two Siemens Westinghouse V84.3a F-Class combustion turbine generators, two heat recovery steam generators (HRSGs) with duct burners; a single condensing Steam Turbine Generator; a deaereating surface condenser; a bank of mechanical draft wet cooling towers; and associated support equipment. The F-Class CTG refers to a series of gas combustion turbines using advanced combustion technology developed in the 1990s which achieve combined cycle efficiencies near 58% with reduced emissions. The two largest suppliers of these types of turbines are General Electric and Siemens-Westinghouse. Each of the two CTGs will generate approximately 170 MW. The CTGs will be equipped with either an evaporative inlet cooling system or a chilled water inlet air cooling system using mechanical refrigeration equipment and chillers to increase plant output during periods of high ambient temperature conditions. The exhaust gas from each CTG is routed to a triple pressure HRSG to generate steam for the STG.

Steam from the two HRSGs is combined and taken to one triple pressure STG. Duct firing will be provided in the HRSGs, and will be used to supplement steam generating capacity during summer conditions when exhaust energy from the CTGs declines. Approximately 180 MW will be produced by the steam turbine. Cooling water for the STG condenser is provided by circulating water through wet cooling towers. These primary plant processes are supported by auxiliary and ancillary equipment referred to as "Balance of Plant" (BOP), which includes an automated control system. BEP II is expected to have an average annual availability greater than 95% (i.e., it will be available to operate more than 95% of the time). Most of the time, the plant is expected to operate at full load. The design does allow the flexibility to rapidly adjust the generation output or for cycling the plant on and off as required to meet demand. A graphic representation of BEP II is shown in **Figure 4 (South Elevation View)** and **Figure 5 (East Elevation View)**.

The plant will be designed and controlled to meet emission limits required by the Mojave Desert Air Quality Management District. NO_x emissions will be controlled to 2.5 ppm by volume, dry basis corrected to 15% oxygen. This emission level will be achieved by a combination of the dry low NO_x combustors in the CTGs and an SCR system in the HRSG. Carbon monoxide (CO) will be controlled to 5 ppm by volume at 15% oxygen in the CTG combustors; however CO will increase upward to 8.4 ppm by volume during operation between 75% and 80% load and during duct firing. Volatile Organic Compound (VOC) emissions will be controlled to 1 ppm and ammonia slip will be controlled to 10 ppm. PM_{10} emissions from the cooling water towers will be minimized by a high efficiency drift elimination design.

Power Plant Cycle

CTG combustion air will flow through the inlet air filters, inlet air cooling system, and air inlet ductwork into the compressor section of the CTG. The air will be compressed as it flows through the 17 stages of the compressor, where it then enters the CTG combustion chamber. Natural gas fuel will be injected into the combustion chamber and ignited. The hot combustion gases will expand through the turbine sections of the CTGs, causing them to rotate and drive the electric generators and CTG compressors.

The hot combustion gases then exit the turbine sections and enter the HRSG. As the hot gas passes through the sections of the HRSG, heat is transferred from the hot gases to the surfaces of the tube bundles through which water is flowing. Water will be converted to superheated steam and delivered to the steam turbine at three pressures: high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP). The use of multiple steam delivery pressures will provide an increase in cycle efficiency and flexibility. High-pressure steam, delivered to the HP section of the steam turbine, will exit the HP section as cold reheat steam and be combined with IP steam to pass through the reheater section of the HRSGs. This mixed, reheated steam (called "hot reheat") will then be delivered to the IP steam turbine section. Steam exiting the IP section of the steam turbine will be mixed with LP steam and expanded in the LP steam turbine section. Steam leaving the LP section of the steam turbine will enter the surface condenser, which transfers heat to cooling water circulating in tube bundles. The steam is condensed to water and is delivered back through the cycle to the HRSG feedwater system. The cooling water will circulate through a mechanical draft wet cooling tower where the latent heat will be dissipated to the atmosphere.

The air inlet system provides filtered air to the combustion turbine compressor. The system is equipped with multi-stage, self cleaning and static filters. Silencers are installed to reduce the noise emissions from the gas turbine compressor inlet. The CTGs and accessory equipment will also be contained in a turbine hall with engineered noise control features. The inlet air cooling system will be either an evaporative type system or a mechanical chiller system. The selection of air cooling system will be decided during the final design stage by the project applicant.

Major Electrical Equipment and Systems

The BEP II will generate electrical power at 16 kV, and step the voltage up to 500 kV for delivery to the electrical grid. Power will be transmitted to the Buck Boulevard Substation owned and operated by Western via a 2,500 foot long 500 kV outlet transmission line. Some of the BEP II facility power will be used onsite for loads for the project such as pumps, fans, control systems, and general facility loads, including lighting, and heating, ventilation and air conditioning (HVAC) systems. Internal power will also be converted via battery chargers to direct current (DC) for supply to control systems and for backup power to critical loads such as oil pumps in the event that AC power supply is lost.

The electrical system can be described according to voltage levels:

- 500 kV - Main switchyard and grid connection
- 161/230 kV connection at Buck Boulevard Substation
- 16 kV - Generator voltage
- 4.16 kV - Station supply to low voltage transformers and large motor loads
- 480 volt – Motor Control Centers (MCC's) for small auxiliary motors
- 120/240 volt - Lighting, HVAC, receptacles, and small motor loads
- 125 volt DC - Switchgear control and backup power to critical loads

- 24 volt DC - Instrumentation and control power

Fuel System

The BEP II will use the same natural gas fuel source as BEP I. Fuel gas will be supplied to the project from the interconnection with the El Paso Gas System. As described in BEP I, the El Paso Gas source is on the eastern or Arizona side of the Colorado River. The new line has been constructed from the El Paso Natural Gas (EPNG) facility near Ehrenberg, Arizona, under the river and then about 11 miles to the BEP I plant. This new gas line has the capability to supply natural gas to both BEP I and the proposed BEP II.

The natural gas consumption during base load operation of the BEP II is approximately 84,400 MMbtu per day or approximately 31 million MMbtu per year. The pressure of natural gas delivered to the site via pipeline is expected to be 550 to 800 pounds per square inch gauge (psig). The range of pressure is higher than the inlet pressure required by the CTGs. The gas will flow through gas scrubber/filtering equipment, a gas pressure control station, and flow metering equipment before entering the combustion turbines or duct burners. A pipeline will be constructed from the BEP I gas supply system on the site property to interconnect with BEP II.

Water Supply and Use

The AFC's proposed raw water supply for all plant uses will be from two 3,000 gpm groundwater wells to be constructed on the plant site or immediate area. The wells will be in addition to the wells that were constructed for BEP I. The maximum rate of usage for BEP II is approximately 3,000 gpm for all uses combined. The average rate of usage is expected to be about 2,200 gpm. Annual consumption of water is approximately 3,300 acre-feet. This is described in detail in the **Water and Soil Resources** section of the FSA. Wastewater will be treated and recycled to provide total consumption (zero discharge off site) of water under normal conditions. A septic treatment and disposal system will be provided for sanitary wastewater. An evaporation pond will be provided to receive and dispose by evaporation any water that cannot be reused. These systems are described in the **Waste Management** section of the FSA. Additional details regarding requirements, supply, quality and treatment are given in the following sections.

Water Requirements

Water use requirements include makeup water for the cooling systems, demineralized water for makeup to the steam system, potable water, and the evaporative inlet air cooling system. The largest requirement is makeup to the circulating cooling water system due to evaporation. In order to minimize the amount of water taken from the wells, the water is reused and recovered whenever possible.

Demineralized water will be produced with a reverse osmosis (RO) unit in series with an electrodeionization (EDI) unit. The water supply for the demineralizer may be taken from the raw water storage system via the potable water system or from the effluent of the brine concentrator (distillate). The average rate of use of demineralized water will be about 40 gpm for makeup to the HRSG steam cycle. A storage tank with 600,000 gallon capacity will be provided for the demineralized water, to allow operation of the

demineralizing unit at more uniform flow rates and to provide a backup supply in the event the demineralizing system is out of service. This will provide about 7 days of backup capacity at the average rate of use. The potable water requirement is far smaller than the other requirements, at an estimated average of 1 gpm.

Providing water for the fire protection system is another requirement of the water system. BEP II may have a fire protection system integrated with the BEP I fire protection system. A connection to the BEP I fire protection system may be provided to share stored water between the projects. In addition to the minimum 300,000 gallons maintained in the raw water storage tank for fire protection, the on-site wells will be capable of restoring the raw water supply at a rate greater than the rating of the fire water pumps. The fire suppression system is designed to operate with a single 2,500 gpm fire water pump.

Water Conservation Offset Program

The BEP II would use about 3,300 acre-feet of water annually for cooling and other purposes, supplied by on-site wells. BEP II has proposed a water conservation offset program (WCOP). As part of this water conservation effort, the WCOP would retire or fallow lands within the Palo Verde Irrigation District's (PVID) service area that are or have been irrigated within the past five years. These lands also would be situated in the Mesa Verde and/or the Palo Verde Valley. Based on a consumptive water use volume of 4.2 acre-feet per acre per year and BEP II's proposed usage of 3,300 acre-feet of water per year, the WCOP for BEP II would fallow about 786 acres of irrigated farmland every year for the life of the project.

Water Treatment Plant

The project's water treatment plant will consist of an evaporator (brine concentrator) for process waste treatment, a reverse osmosis (RO) unit for potable water processing; an RO unit and an electrodeionization (EDI) unit for demineralized water processing.

The evaporator works on a mechanical vapor recompression process. At design conditions it will have 416 gallons per minute of cooling tower blowdown as feed. Approximately 94.5 percent of the feed is returned to the project as distillate and 4.5 percent is directed to the evaporation ponds as brine.

Management of Hazardous Materials

Materials qualified as hazardous, including solvents, acid, and oil will be stored and used during the construction and operation of BEP II. All materials will be stored, handled, and used in accordance with applicable Laws, Ordinances, Regulations, and Standards (LORS). Chemicals will be stored in appropriate chemical storage facilities. Bulk chemicals will be stored in storage tanks, and other chemicals will be stored in returnable delivery containers. Chemical storage and chemical feed areas will be designed to contain leaks and spills. Berms and drain piping design will allow a full-tank capacity spill without overflowing the berms. For multiple tanks located within the same bermed area, the capacity of the largest single tank will determine the volume of the bermed area and drain piping. Drains from the chemical storage and feed areas will be directed to a neutralization area for neutralization, if necessary. Drain piping for volatile

chemicals will be trapped and isolated from other drains to eliminate noxious or toxic vapors. After neutralization, water collected from the chemical storage areas will be directed to the cooling tower basin whenever possible.

Aqueous ammonia (19.5 to 30 percent ammonia in aqueous solution) and anhydrous ammonia are the only acutely hazardous material proposed to be used or stored at the BEP II in quantities exceeding the reportable amounts defined in the California Health and Safety Code, section 25532 (j) (BEP II 2003f, Table 7.9-2). Aqueous ammonia would be used for controlling oxides of nitrogen (NO_x) emissions through selective catalytic reduction and for condensate pH control. Anhydrous ammonia will be used in the inlet chilling system.

The water treatment system will use sulfuric acid and calcium chloride in the processing of the cooling tower blowdown. These chemicals will be stored in storage tanks at the water treatment plant. Anti-scalant and sodium hypochlorite will be used in the processing of potable water; these chemicals will be stored in tanks at the water treatment plant.

Safety showers and eyewashes will be provided adjacent to, or in the area of, all chemical storage and use areas. Hose connections will be provided near the chemical storage and feed areas to flush spills and leaks to the neutralization facility. State-approved personal protective equipment will be used by plant personnel during chemical spill containment and cleanup activities. Personnel will be properly trained in the handling of these chemicals and instructed in the procedures to follow in case of a chemical spill or accidental release. Adequate supplies of absorbent material will be stored onsite for spill cleanup.

Electric equipment insulating materials will be specified to be free of polychlorinated biphenyls (PCB).

Hazardous Wastes

Hazardous wastes generated by the BEP II will include mineral and lubricating oils, corrosion inhibitors and water conditioners typical of modern power plant operation. Waste lubricating oil will be recovered and recycled by a waste oil recycling contractor. Used oil filters will be disposed of in a Class I landfill. Spent SCR catalyst will be recycled by the supplier or disposed of in a Class I landfill. Workers will be trained to handle any hazardous waste generated at the site. Chemical cleaning wastes will consist of alkaline and acid cleaning solutions used during pre-operational chemical cleaning of the HRSGs, acid cleaning solutions used for chemical cleaning of the HRSGs after the units are put into service, chemical solutions used for periodic cleaning of the brine concentrator tube surfaces, and turbine wash and HRSG fireside wash waters. These wastes, which are subject to high metal concentrations, will be stored temporarily onsite in portable tanks. They will be disposed of in accordance with applicable regulatory requirements.

Surface Water Runoff – Retention Basin

Surface water runoff from the area used for BEP II and auxiliary systems will be discharged to the existing BEP I stormwater retention basin. The BEP I retention basin,

located on the south side of the BEP I site, will be utilized to contain runoff both during construction and operation of BEP II. The stormwater retention basin is an earth embankment constructed from on-site materials. The retention basin was designed to capture and percolate the water in accordance with City of Blythe design standards

Since the BEP I site slopes gently from the northwest to the southeast, the final grading and associated drainage appurtenances have been constructed to accept offsite flows from the west and north. Most of the offsite flows from the north are intercepted and directed easterly along the north side of Riverside Avenue to a storm water inlet structure located at the northwest corner of the Riverside Avenue/Buck Boulevard intersection. This structure is capable of accepting a peak flow of 120 cubic feet per second (cfs) which is conveyed to the retention basin located at the south end of the BEP I site by twin 42-inch diameter storm drains.

The BEP I retention basin encompasses an area of approximately 11 acres with depths of about 20 feet. The basin is capable of accommodating 8,989,000 cubic feet (206 acre-ft) of runoff. The basin was constructed by excavating the existing soils and constructing earthen embankments.

Onsite flows from the BEP I power island area will be conveyed via drainage channels. The BEP I design has been approved by the CBO. These drainage channels are capable of accommodating a peak discharge of 90 cfs.

The construction of the Riverside Avenue secondary access road westerly to the Blythe Airport will include three concrete cross-gutters that will accept minor offsite storm water flows from the north. These flows will be channelized into drainage swales that will be graded from north to south on both the east and west sides of the relocated evaporation basins. These trapezoidal swales will also be sized to accommodate onsite drainage from the water treatment plant area and the open areas surrounding the relocated evaporation basins. The swales will terminate at the east and west ends of the west retention basin with peak discharges of 50 and 10 cfs, respectively. The swale along the west side of the evaporation basins will also be sized to intercept minor flows from the airport property located westerly of the BEP I site.

Project Construction

Construction of the generating facility for the BEP II, from site preparation and grading to commercial operation, is expected to last approximately 18-22 months.

During construction, land around the BEP II power island will be used for construction laydown and parking. Construction access to the project site will be from Interstate 10 to Hobsonway and then to Buck Boulevard.

The average workforce on the project during construction will be approximately 232 including construction craft persons and supervisory, support, and construction management personnel. The peak construction workforce of 387 is expected to occur during the 12th month of construction.

Construction will be scheduled 7 days a week and 24 hours a day as needed. Additional hours may be necessary to make up schedule deficiencies or to complete

critical construction activities. During the start-up phase of the BEP II, some activities will continue 24 hours per day, 7 days per week.

JOINT CEQA/NEPA PROCESS

Caithness Blythe II has filed a request with Western to interconnect the proposed BEP II power plant at the Buck Boulevard Substation. Western is proposing modifications at its Buck Boulevard Substation to accommodate the interconnection of the proposed power plant. Because BEP II has proposed to interconnect to Western's power system, the interconnection request triggers a Federal NEPA review process in addition to the Energy Commission's CEQA permitting process. Western will also be the lead Federal agency for compliance with the National Historic Preservation and Endangered Species acts.

REFERENCES

BEP II (Blythe Energy Project Phase II). 2002a. Submittal of the Application for Certification (AFC), Vol 1 & 2. 02/20/2002 (tn: 24604)

BEP II (Blythe Energy Project Phase II). 2002d. Revised Application for Certification for Blythe II. 07/03/2002 (tn: 26100)

BEP II (Blythe Energy Project Phase II). 2002f. Data Responses #1-102 (set #1). 09/30/2002 (tn: 26909)

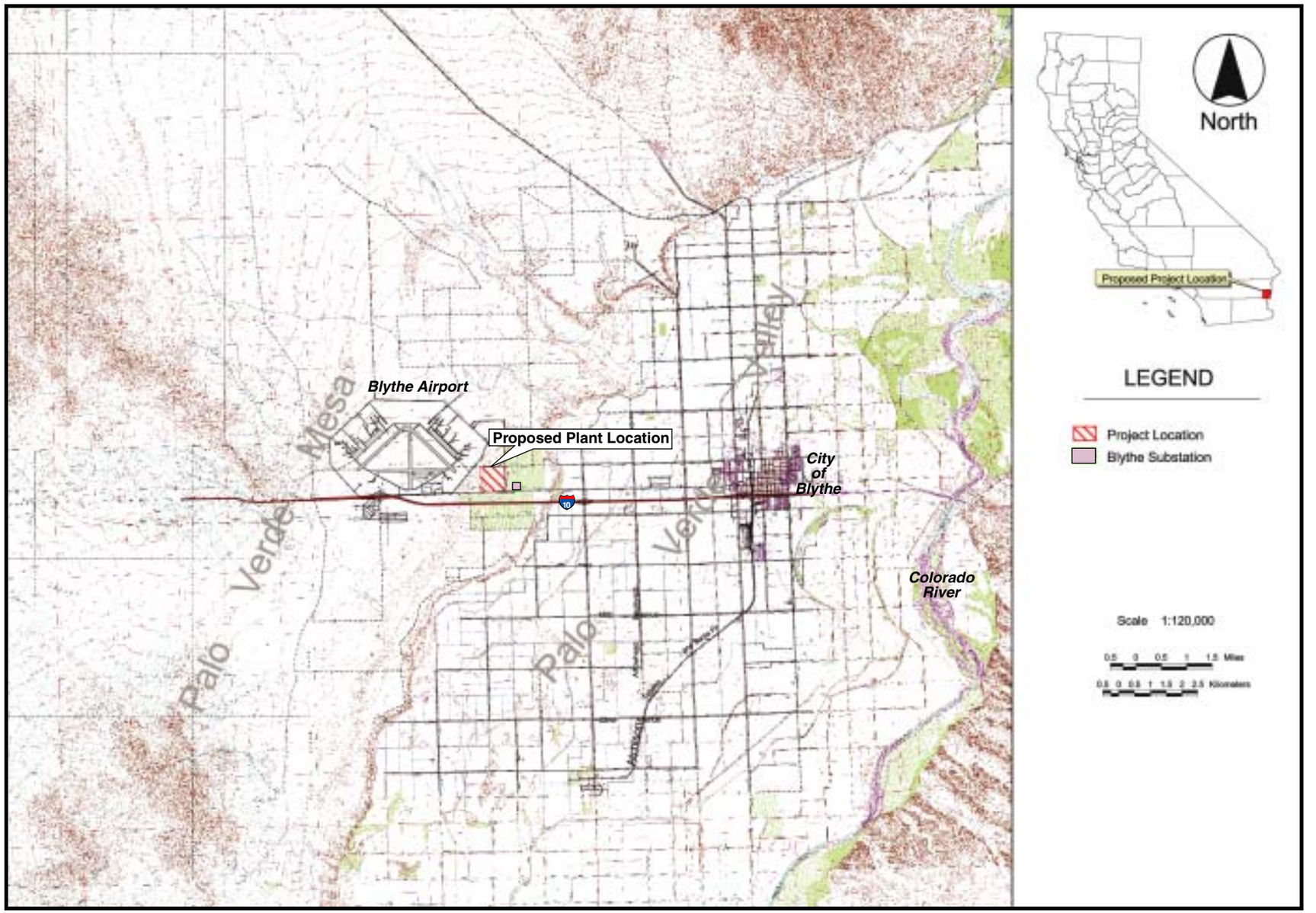
BEP II (Blythe Energy Project Phase II). 2003b. Second Round Data Responses #103-188. 03/14/03 (tn: 28226)

BEP II (Blythe Energy Project Phase II). 2003e. Response to Data Request #189-235. 06/13/2003 (tn: 29006)

BEP II (Blythe Energy Project Phase II). 2004d. Revision to Section 2.0 of the Blythe Energy Project Phase II. POS. 04/21/2004 (tn: 31295)

PROJECT DESCRIPTION - FIGURE 1

Blythe Energy Project II - Regional Location of the Proposed Project

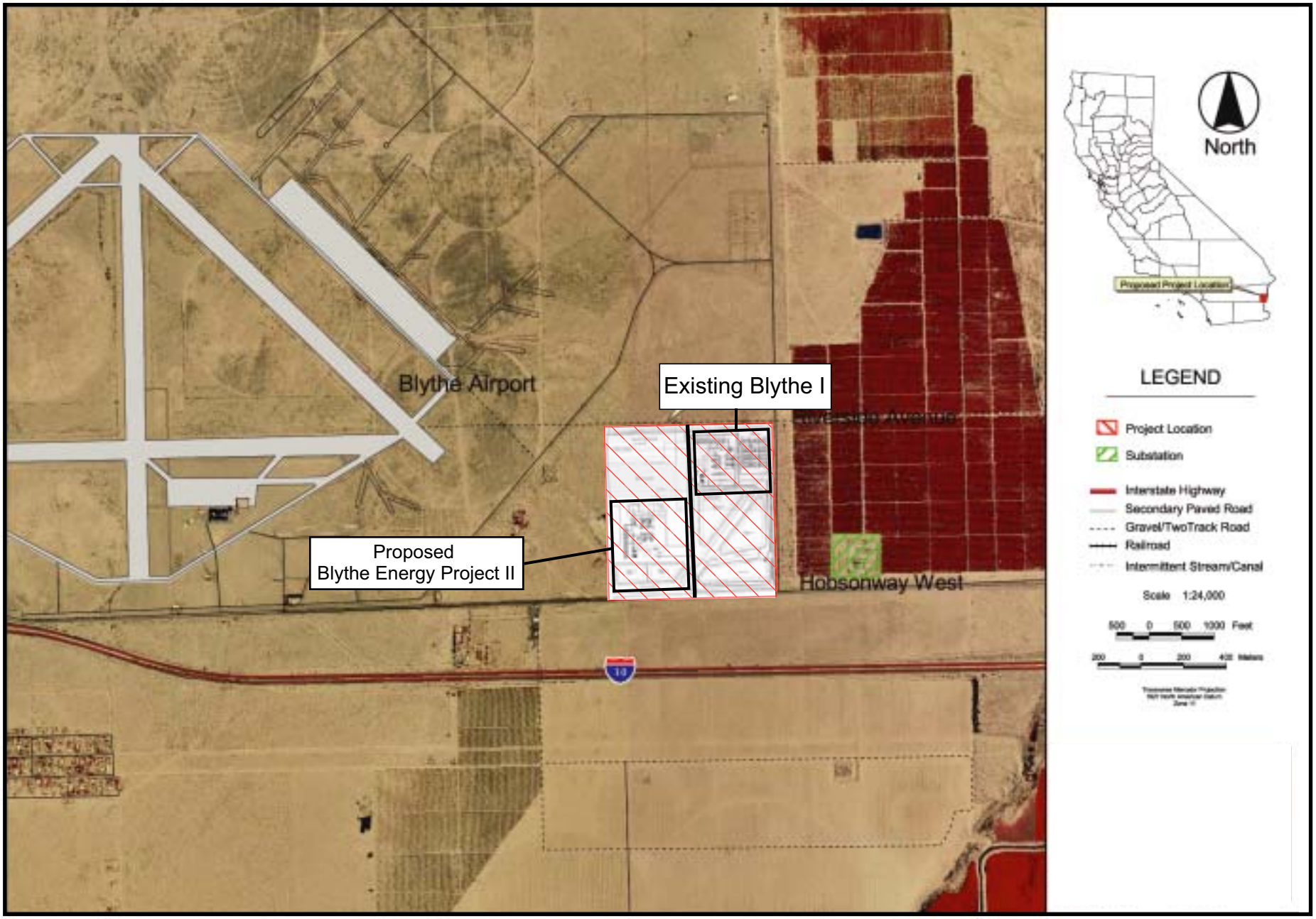


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: AFC Figure 2.0-1

PROJECT DESCRIPTION - FIGURE 2

Blythe Energy Project II - Immediate Vicinity of Proposed Project

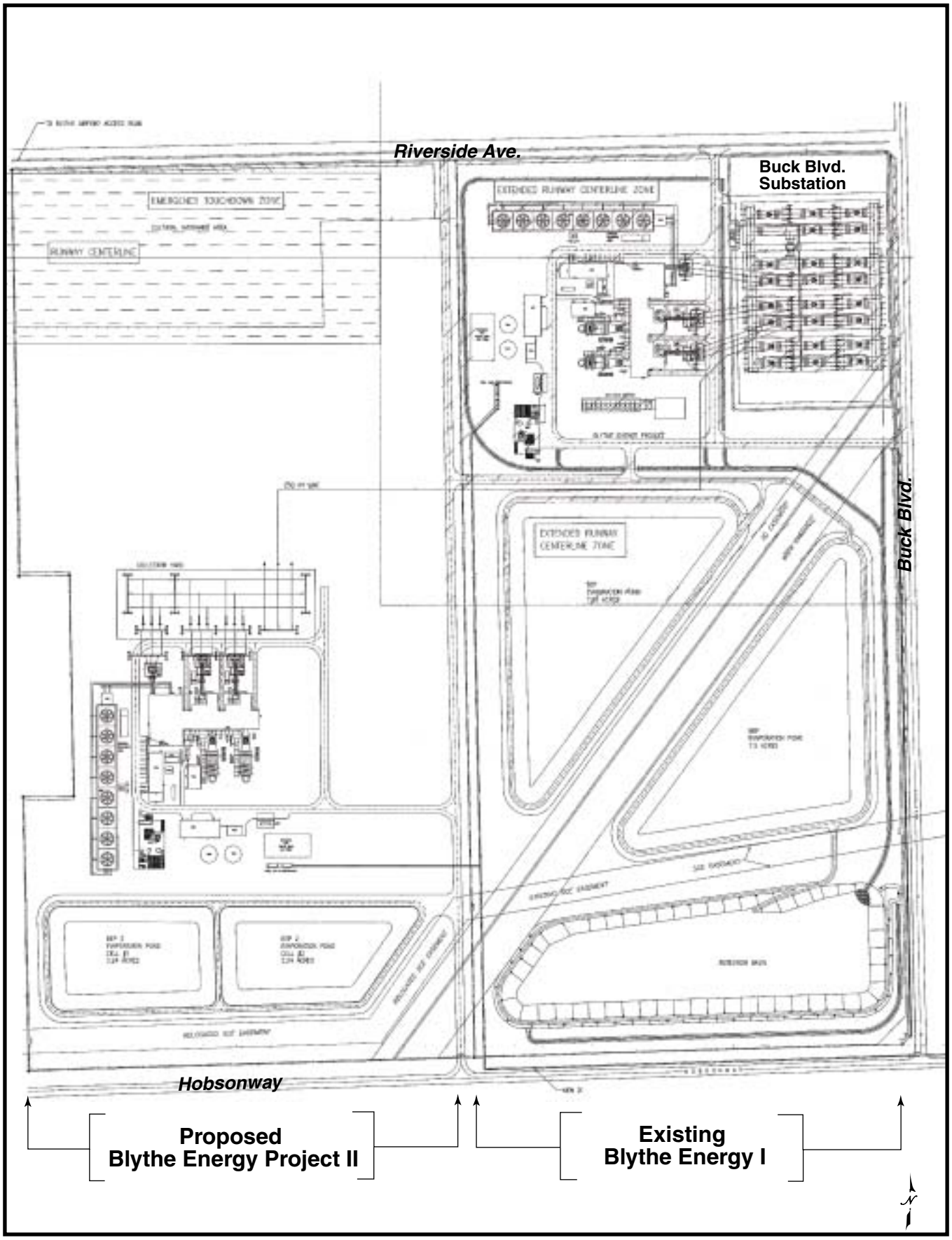


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: AFC Figure 2.0-3

PROJECT DESCRIPTION - FIGURE 3

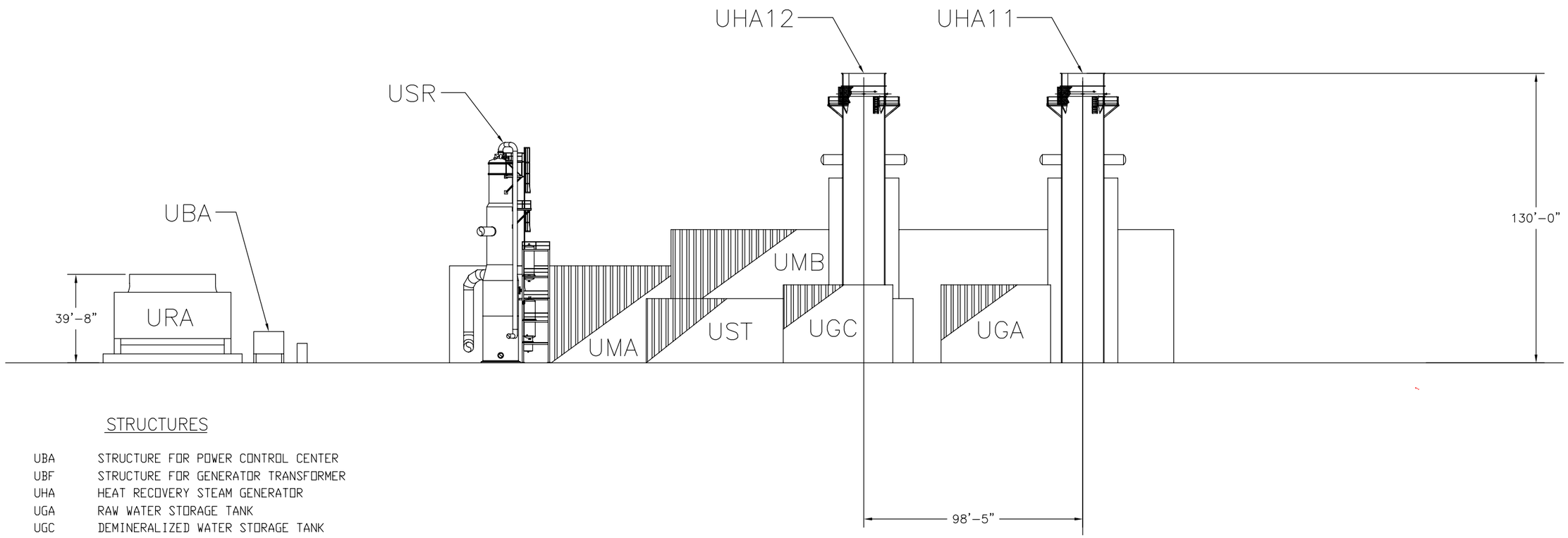
Blythe Energy Project II - Site Plan / Layout



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: AFC Figure 36-1

PROJECT DESCRIPTION - FIGURE 4
Blythe Energy Project Phase II - South Elevation View



STRUCTURES

UBA	STRUCTURE FOR POWER CONTROL CENTER
UBF	STRUCTURE FOR GENERATOR TRANSFORMER
UHA	HEAT RECOVERY STEAM GENERATOR
UGA	RAW WATER STORAGE TANK
UGC	DEMINERALIZED WATER STORAGE TANK
UMA/UMB	STEAM /GAS TURBINE GENERATOR BUILDING
URA	COOLING TOWER STRUCTURE
USG	FIRE PUMP HOUSE
USR	WASTE WATER TREATMENT AREA
UST	WORKSHOP / STORAGE AREA

0' 15' 30' 60' 90'

BEP II

SECTION A
0077-002

SCALE: 1"=60'-0"

NOTES:

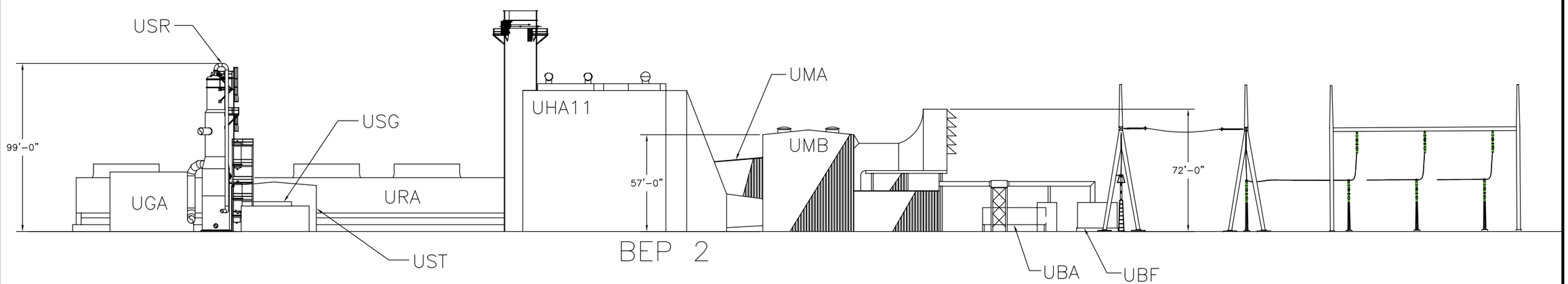
1. THE EQUIPMENT SHOWN IS REPRESENTATIVE INFORMATION. THIS DESIGN IS SUBJECT TO CHANGE.
2. ALL DIMENSIONS SHOWN ARE IN FEET AND INCHES.
3. BEP 1 CHILLER EQUIPMENT OMITTED FOR CLARITY.
4. WATER TREATMENT EQUIPMENT EXCEPT FOR BRINE CONCENTRATOR OMITTED.
5. EVAPORAZATION PONDS OMITTED FOR CLARITY.

PROJECT DESCRIPTION

APRIL 2005

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005
SOURCE: BEP II 2002a, Figure 7.5-10c
SOURCE: PATCH INC.

PROJECT DESCRIPTION - FIGURE 5
Blythe Energy Project Phase II - East Elevation View



STRUCTURES

UBA	STRUCTURE FOR POWER CONTROL CENTER
UBF	STRUCTURE FOR GENERATOR TRANSFORMER
UHA	HEAT RECOVERY STEAM GENERATOR
UGA	RAW WATER STORAGE TANK
UGC	DEMINERALIZED WATER STORAGE TANK
UMA/UMB	STEAM /GAS TURBINE GENERATOR BUILDING
URA	COOLING TOWER STRUCTURE
USG	FIRE PUMP HOUSE
USR	WASTE WATER TREATMENT AREA
UST	WORKSHOP / STORAGE AREA
USA	INLET CHILLER EQUIPMENT

BEP II

SECTION C
SCALE: 1"=60'-0"
0077-002

0' 15' 30' 60' 90'

NOTES:

1. THE EQUIPMENT SHOWN IS REPRESENTATIVE INFORMATION. THIS DESIGN IS SUBJECT TO CHANGE.
2. ALL DIMENSIONS SHOWN ARE IN FEET AND INCHES.
3. WATER TREATMENT EQUIPMENT EXCEPT FOR BRINE CONCENTRATOR OMITTED.
4. EVAPORAZATION PONDS OMITTED FOR CLARITY.

PROJECT DESCRIPTION

APRIL 2005

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005
SOURCE: BEP II 2002a, Figure 7.5-10b
SOURCE: PATCH INC.

Environmental

Assessment

AIR QUALITY

Testimony of Brewster Birdsall

INTRODUCTION

In this analysis, staff evaluated the expected air quality impacts from construction and operation of the Blythe Energy Project Phase II (BEP II). The following major points were evaluated:

- whether the proposed BEP II is likely to conform with applicable Federal, State and Mojave Desert Air Quality Management District (MDAQMD, or District) air quality laws, ordinances, regulations and standards (Cal. Code Regs., tit. 20, § 1744(b)); and
- whether the proposed BEP II is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards and whether the mitigation proposed for BEP II is adequate to lessen the potential impacts to a level of insignificance (Cal. Code Regs., tit. 20, § 1742(b)).

The analysis addresses criteria pollutants that are managed according to federal or state ambient air quality standards to protect public health. They include ozone, nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), reactive organic gases (ROGs, including volatile organic compounds, or VOCs), and particulate matter less than ten microns in diameter (PM10) and less than 2.5 microns in diameter (PM2.5). Non-criteria pollutants such as benzene, formaldehyde and acetaldehyde are analyzed in the **Public Health** section.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

The federal Clean Air Act requires that any new major stationary sources of air pollution and any major modifications to existing major stationary sources 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 with the national ambient air quality standards. Nonattainment NSR applies in areas where certain pollutants do not comply with national ambient air quality standards. The entire program, including both PSD and nonattainment NSR, is referred to as the federal NSR program.

Title V of the federal Clean Air Act requires implementation and administration of an operating permit program to ensure that large sources operate in compliance with the requirements included in the Code of Federal Regulations (CFR), Title 40, Part 70 (40 CFR 70). A Title V permit contains all of the requirements specified in different air quality regulations that affect an individual project.

Title IV of the federal Clean Air Act requires implementation of an acid rain permit program (40 CFR 72). These regulations require subject facilities to obtain emission allowances for oxides of sulfur (SOx) emissions.

The U.S. Environmental Protection Agency (U.S. EPA) has reviewed and approved the Mojave Desert Air Quality Management District (MDAQMD, or District) regulations for the nonattainment NSR, Title V, and Title IV programs. These federal permitting programs have been delegated to the MDAQMD for implementation (District Regulation XII for federal Title V and Regulation XIII for nonattainment NSR). The MDAQMD rules and regulations implementing the federal programs are as stringent as the federal regulations.

The federal PSD program (40 CFR 52.21) is implemented by the U.S. EPA, which means that an independent application must be filed with the U.S. EPA in order to secure this federal permit. BEP II originally submitted the PSD application in May 2002, and the U.S. EPA provided a preliminary analysis of compliance in April 2003. BEP II intends to modify the draft PSD permit in 2005 to address startup emissions, but at this time, the request has not yet been submitted.

BEP II is also subject to the federal New Source Performance Standards (NSPS) contained in 40 CFR 60. Enforcement of NSPS has been delegated to the MDAQMD (District Regulation IX). The proposed combined cycle power plant must comply with the requirements of NSPS Subparts Da and GG (for the duct burners and stationary gas turbines, respectively). The federal NSPS allowable emissions concentration for nitrogen oxides (NOx) is 75 parts per million volume dry (ppmvd) at 15% oxygen (O_2), and the NSPS requirement for SO_2 emissions concentration is 150 ppm at 15% O_2.

The first phase and existing Blythe Energy Project (BEP I) is a major stationary source for NOx, CO, and PM10. According to the requirements of the MDAQMD NSR programs, BEP II would be a major modification to this major source. Modification of BEP I by adding BEP II would result in a new stationary source that would be classified as major for these three pollutants plus VOC and SOx (MDAQMD 2004a).

STATE

California State Health and Safety Code, Section 41700, requires that: “no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any 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.”

LOCAL

As part of the Energy Commission’s licensing process, the MDAQMD released a Final Determination of Compliance (FDOC) on May 3, 2004 (MDAQMD 2004a) for BEP II. The Preliminary Determination of Compliance (PDOC) was originally issued in 2002 and followed by a public comment period. The FDOC incorporates changes made in response to the comments and evaluates whether and under what conditions the proposed project will comply with the applicable rules and regulations. The review by

the MDAQMD for the FDOC is conducted in a manner that is equivalent to that for other permits to construct and independent of the federal PSD program. The Energy Commission staff coordinates its analysis with that for the FDOC. Provided successful completion of the Energy Commission's licensing process and incorporation of the District's conditions into the decision granted by the Energy Commission, the Determination of Compliance serves as an equivalent to an Authority to Construct (ATC). A Permit to Operate (PTO) would be issued by the District provided the construction is in compliance with the conditions of the Determination of Compliance and the Energy Commission decision.

The project is subject to certain specific MDAQMD rules and regulations that are summarized below:

Regulation II – Permits

RULE 201 – PERMIT TO CONSTRUCT

Requires the District's authorization, or an ATC, prior to construction of a new facility.

RULE 203 – PERMIT TO OPERATE

Requires the District's authorization, or a PTO, before a new facility commences operations.

RULE 219 – EQUIPMENT NOT REQUIRING A PERMIT

Describes sources that do not require a permit under Rules 201 or 203, including water cooling towers and ponds that have a circulation rate of less than 10,000 gallons per minute.

RULE 221 – FEDERAL OPERATING PERMIT REQUIREMENTS

Requires submittal of an application for a federal operating permit within twelve months of commencing operation.

Regulation IV – Prohibitions

RULE 401 – VISIBLE EMISSIONS

This rule contains general requirements limiting visible emissions to no darker than Ringelmann No. 1 (20 percent opacity) for periods greater than three minutes in any hour.

RULE 402 – NUISANCE

Prohibits any emissions "which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such person or public or which cause or have a natural tendency to cause injury or damage to business or property."

RULE 403 – FUGITIVE DUST

Regulates operations that may cause fugitive dust emissions into the atmosphere. Emissions of fugitive dust from transport, handling, construction or storage activities shall not remain visible in the atmosphere beyond the property line of the emission source, or exceed 100 micrograms per cubic meter when determined as the difference between upwind and downwind samples collected on high volume samplers at the property line for a minimum of five hours. These limits are not applicable when the wind speed instantaneously exceeds 40 kilometers (25 miles) per hour, or when the average wind speed is greater than 24 kilometers (15 miles) per hour. The average wind speed determination shall be on a 15 minute average at the nearest official air-monitoring station or by wind instrument located at the site being checked.

RULE 403.2 – FUGITIVE DUST FOR THE MOJAVE DESERT PLANNING AREA

Limits emissions from construction activities, publicly maintained unpaved roads, and activity on other public lands to ensure that dust emissions in the Mojave Desert Planning Area are managed. This only applies to sources in San Bernardino County.

RULE 406 – SPECIFIC CONTAMINANTS

Limits the emissions of sulfur compounds to no greater than 500 parts per million by volume (ppmv), and a number of other contaminants (such as bromine, hydrogen chloride and fluorine) to specific ppmv levels.

RULE 409 – COMBUSTION CONTAMINANTS

Limits discharging of combustion contaminants (PM10) to no greater than 0.1 grains per dry standard cubic foot (gr/dscf).

RULE 430 – BREAKDOWN PROVISIONS

Requires reporting of breakdowns and excess emissions.

RULE 431 – SULFUR CONTENT OF FUELS

Limits sulfur content of gaseous fuel to 800 ppm, calculated as hydrogen sulfide at standard conditions, and liquid or solid fuel to 0.5 percent by weight.

RULE 475 – ELECTRIC POWER GENERATING EQUIPMENT

Limits the NOx emissions of any electric power generating equipment to no more than 80 ppm if using gaseous fuel, 160 ppm if using liquid fuel and 225 ppm if using solid fuel.

RULE 476 – STEAM GENERATING EQUIPMENT

Limits the emissions of any fuel combustion equipment to no more than 200 pounds per hour of SOx, 140 pounds per hour of NOx, or 10 pounds per hour of combustion contaminants.

Regulation IX – Standards For Performance For New Stationary Sources

Adopts the requirements of the federal NSPS (40 CFR 60) by reference. The federal NSPS requirements for stationary gas turbines and duct burners are described with other federal requirements, above.

Regulation XI – Source Specific Standards

RULE 1158 – ELECTRIC UTILITY OPERATIONS

Establishes NOx emission standards and other requirements for electric utility operations including installation of an approved continuous emission monitoring (CEM) system, reporting and an approved emission control plan.

Regulation XII – Federal Operating Permits

Establishes administrative requirements for obtaining a federal operating permit (federal Clean Air Act Title V) and an acid rain permit (Title IV) by the appropriate dates.

Regulation XIII – New Source Review

RULE 1302 – PROCEDURES, NEW SOURCE REVIEW

Provides administrative procedures for the processing of applications for permits to construct and operate new and modified stationary sources.

Rule 1302(C)(3)(b), Determination of Offsets, states that the applicant shall provide an offset package which contains evidence of offsets eligible for use pursuant to the provisions of Rule 1305.

Rule 1302(C)(3)(b)(iii) states that the District must determine that the offsets are real, enforceable, surplus, permanent and quantifiable and that permit modifications required pursuant to Rule 1305 or Regulation XIV have been made. The District would approve the use of the offsets subject to the approval of California Air Resources Board (CARB) and U.S. EPA during a 30-day public comment period. The District may only issue an ATC after the increase in emissions for each nonattainment pollutant has been properly offset.

Rule 1302(D)(5)(b)(iii) requires that the applicant certify in writing that all facilities which are under the common control of the applicant in the State of California, are in compliance with all applicable emissions limitations and standards under the federal Clean Air Act.

RULE 1303 – REQUIREMENTS, NEW SOURCE REVIEW

Provides specific requirements for new or modified stationary sources including Best Available Control Technology (BACT) and offsets. A modification of a major source must apply BACT for each nonattainment air pollutant for which the potential to emit is greater than 25 pounds per day or 25 tons per year. Offsets must be provided for all pollutants that exceed the specified trigger levels.

RULE 1305 – EMISSIONS OFFSETS

Provides the procedures and formulas for quantifying and determining the eligibility of emission reduction credits (ERCs) available for use as offsets in accordance with Rule 1303.

Rule 1305(B)(5) allows for the use of interbasin offsets from upwind air districts that are outside the Mojave Desert Air Basin. Rule 1305(B)(6) allows for the use of interpollutant offset trading as long as there is technical justification for such a trade and the combined emissions increase from the proposed project and the reductions from the interpollutant offsets do not cause or contribute to a violation of an ambient air quality standard.

New emissions of NOx and PM10 from BEP II must be offset because BEP II would emit these nonattainment pollutants (or precursors) in quantities greater than the offset applicability thresholds in Rule 1303(B). At the time of BEP I permit issuance, BEP I emissions for VOC and SOx did not exceed offset threshold values, and, therefore, did not require offsets. However, as noted earlier, the District considers BEP II to be a major modification to BEP I, and BEP II emissions when combined with the emissions from BEP I will now exceed the Rule 1303(B) offset threshold for both VOC and SOx. Therefore, the entire quantity of VOC and SOx emissions from BEP I and BEP II must be offset by the BEP II modification. The District does not consider ammonia to be a precursor to any regulated pollutant [Rule 1301(VV)].

RULE 1306 - ELECTRIC ENERGY GENERATING FACILITIES

This rule includes the additional administrative requirements for projects that are required to obtain licensing from the Energy Commission and specifies that a determination of compliance would be prepared by the District. The FDOC confers the same rights and privileges as a New Source Review permit or ATC(s) only when the Energy Commission decision includes all conditions contained in the FDOC [Rule 1306(E)(3)(b)].

Regulation XIV– Emission Reduction Credit Banking

RULE 1402 – EMISSION REDUCTION CREDIT REGISTRY

Provides administrative procedures for the registry of ERCs for stationary sources. The requirements include the specific timing of an application for an ERC and criteria for approval of the ERC.

Rule 1402(A)(1)(e)(ii) defines emission reductions to be eligible for ERCs if such reductions are actual emission reductions and either recognized by the District in writing or were included in the emission inventory after the shutdown or modification occurred. Rule 1402(B) requires an application to be submitted and public notice and comment of ERC proposals before valid ERCs can be issued by the District.

RULE 1404 – EMISSION REDUCTION CREDIT CALCULATIONS

Provides methods to calculate the ERC available, as the difference between the historical actual emissions and the proposed emissions. Emission reductions must be

adjusted to reflect only those reductions that are in excess of the reductions achievable by Reasonably Available Control Technology or required by applicable District rules.

SETTING

METEOROLOGICAL CONDITIONS

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

The City of Blythe is located near the border of the Mojave Desert and the Sonoran Desert in the Lower Colorado Valley. Hot, dry summers and mild winters with scant precipitation define the climate. The semi-permanent Pacific High over the eastern Pacific Ocean during the summer months blocks low pressure systems from passing through the area. This results in hot summers, with average daily maximum temperatures during the summer months over 105 ºF. During the winter, the area does not often experience frost. Daily maximum temperatures during the winter months average around 68 ºF, with average wintertime low temperatures being around 40 ºF (WRCC 2002).

During the winter months, the Pacific High weakens and migrates to the south, allowing Pacific storms into California. In addition, the area receives some moisture during the summer monsoon season from the wind flowing up the Colorado River Valley from the Gulf of California. However, due to the rain shadow effect of the mountainous terrain west and south of the Blythe region, the average annual rainfall in the area is only 3.7 inches.

Analysis of the local wind rose diagrams (a graph showing the average wind speed and direction in the location) provided by the applicant in the Application for Certification (AFC) indicate that the surface winds in the area are strongly influenced by the southwest-northeast orientation of the Colorado River directly to the east of the project site (BEP II 2002d, AFC Figures 7.7-4 to 7.7-8). During the summer months (April through September), winds are predominately from the southwest, while during the winter months winds are predominately from the northeast. The winds are calm approximately 15 percent of the time annually and 7 percent of the time during the summer months.

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

consequently higher air quality impacts may result from stationary source emissions. Because lower mixing heights generally occur during the winter, along with lower mean wind speeds and less vertical mixing, dispersion occurs less rapidly.

EXISTING AIR QUALITY

The project is located in the Riverside County portion of the Mojave Desert Air Basin and is under the jurisdiction of the MDAQMD. The U.S. EPA and CARB each designate the status of local air quality through a comparison with the ambient air quality standards (AAQS). The state standards (CAAQS), established by CARB, are typically more restrictive than the federal or national standards (NAAQS), which are established by the U.S. EPA. The state and federal ambient air quality standards are listed in **AIR QUALITY Table 1**. As indicated in this table, the averaging times for the various standards (the duration over which they are measured) range from hourly to annually. 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 per cubic meter of air (mg/m^3 and $\mu g/m^3$).

AIR QUALITY Table 2 shows the area designation status of the Mojave Desert Air Basin for each criteria pollutant for both the federal and state ambient air quality standards. Only ozone and PM10 are designated as nonattainment under the CAAQS.

LOCAL AIR QUALITY DATA

Local ambient air quality conditions are normally determined by a network of monitoring stations, however there are few stations near Blythe. The original BEP I modeling analysis used Twentynine Palms monitoring data for estimated ambient background concentrations. The Twentynine Palms monitoring station is located approximately 90 miles west-northwest of the project site, and indicates violations of the state 24-hour PM10 standard and both the state and federal 1-hour ozone standard. Twentynine Palms is downwind of industrial and urban areas, particularly Victorville and Barstow and to a certain extent, the Los Angeles Basin. Conversely, there are very few sources of industrial pollutants near Blythe. Therefore, it is likely that ozone concentrations in the Blythe area are lower than those measured at Twentynine Palms. An analysis of the trend of ambient ozone concentrations around Blythe was conducted in response to BEP I Data Request 201 in August 2000, which confirmed this conclusion. This analysis was updated for year 2000 ambient air quality data (BEP II 2002d, AFC Appendix 7.7-G), which again concluded that the air quality in Blythe is better than or equal to 1992 air quality, the last year for which Blythe area data are available.

No information on ozone concentrations in the Blythe area is available from the Arizona Department of Environmental Quality (ADEQ). The ADEQ does operate an ozone monitoring station in Yuma, approximately 90 miles south of Blythe along the Colorado River. For the year 2000, maximum ozone concentrations in Yuma were below the Twentynine Palms concentrations. The maximum monitored ozone concentrations in Yuma were 0.077 ppm (1-hour) and 0.068 ppm (8-hour) (ADEQ 2001). These concentrations are below the most restrictive CAAQS and NAAQS.

AIR QUALITY Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	1 Hour	0.12 ppm (235 μg/m^3)	0.09 ppm (180 μg/m^3)
	8 Hour	0.08 ppm (160 μg/m^3)	—
Respirable Particulate Matter (PM10)	24 Hour	150 μg/m^3	50 μg/m^3
	Annual Average	50 μg/m^3	20 μg/m^3
Fine Particulate Matter (PM2.5)	24 Hour	65 μg/m^3	—
	Annual Average	15 μg/m^3	12 μg/m^3
Nitrogen Dioxide (NO_2)	Annual Average	0.053 ppm (100 μg/m^3)	—
	1 Hour	—	0.25 ppm (470 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Sulfur Dioxide (SO_2)	Annual Average	0.03 ppm (80 μg/m^3)	—
	24 Hour	0.14 ppm (365 μg/m^3)	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1300 μg/m^3)	—
	1 Hour	—	0.25 ppm (655 μg/m^3)
Sulfates (SO_4^{2-})	24 Hour	—	25 μg/m^3
Lead	30 Day Average	—	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	—
Hydrogen Sulfide(H_2S)	1 Hour	—	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.010 ppm (26 μg/m^3)
Visibility Reducing Particulates	1 Observation	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

AIR QUALITY Table 2
Federal and State Area Designations for the Mojave Desert Air Basin

Pollutants	Federal Classification	State Classification
Ozone	Unclassified/Attainment	Moderate Nonattainment
PM10	Unclassified/Attainment	Nonattainment
PM2.5	Unclassified/Attainment	Unclassified
NO_2	Unclassified/Attainment	Attainment
CO	Unclassified/Attainment	Unclassified
SO_2	Unclassified/Attainment	Attainment

The most-recent air quality data from the Twentynine Palms station is presented in **AIR QUALITY Table 3**. Data in **bold** format represents the highest historical value and the value used in the staff assessment of project impacts.

Ozone

In the presence of ultraviolet radiation, both NOx and VOC go through a number of complex chemical reactions to form ozone. Ozone formation is highest in the spring and summer, when abundant sunshine and high temperatures are available to trigger the necessary photochemical reactions, while concentrations are lowest in the winter. **AIR QUALITY Table 3** summarizes the most-representative ambient ozone data collected from the Twentynine Palms monitoring station.

AIR QUALITY Table 3
Ambient Air Quality Monitoring Data, Twentynine Palms – Adobe Road #2

Pollutant	Standard	1996	1997	1998	2001	2002	2003	Most Restrictive Standard
Ozone	Maximum 1-hour Average (ppm)	0.121	0.115	0.118	**0.124**	0.099	0.100	0.09 (CAAQS)
	Month of Maximum 1-hour	Jul	May	Jun	Aug	Jun	Jun	—
	# of days exceeding CAAQS	19	15	13	12	2	4	—
	Maximum 8-hour Average (ppm)	0.101	0.104	0.110	**0.112**	0.091	0.091	0.08 (NAAQS)
	Month of Maximum 8-hour	Jun	Jul	Jul	Aug	Jun	Jun	—
	# of days exceeding NAAQS	20	14	11	9	4	3	—
PM10	Maximum 24-hour Average ($\mu g/m^3$)	47	30	30	**84**	55	70	50.0 (CAAQS)
	Month of Maximum 24-hour	---	May	Jul	Aug	May	Sep	—
	# of days exceeding CAAQS*	0	0	0	12	12	3	—
	Annual Arithmetic Mean ($\mu g/m^3$)	22.5	16.6	15.6	20	**24**	17.3	20 (CAAQS)
NO_2	Maximum 1-hour Average (ppm)	0.035	**0.037**	0.036	---	---	---	0.25 (CAAQS)
	Average annual concentration (ppm)	0.006	**0.006**	---	---	---	---	0.053 (NAAQS)
CO	Maximum 1-hour Average (ppm)	1.9	**2**	---	---	---	---	20 (CAAQS)
	Maximum 8-hour Average (ppm)	**1.31**	1.03	---	---	---	---	9 (CAAQS)
SO_2	Maximum 1-hour Average (ppm)	0.005	**0.008**	---	---	---	---	0.25 (CAAQS)
	Maximum 24-hour Average (ppm)	**0.004**	0.002	---	---	---	---	0.04 (CAAQS)
	Annual Average (ppm)	0.001	**0.001**	---	---	---	---	0.03 (NAAQS)

Source: CARB web site: http://www.arb.ca.gov/adam/welcome.html, accessed Feb. 2005.

Highest monitored concentrations, used in this assessment, shown in **bold**.

No additional records of NO_2, CO, or SO_2 are available after 1998.

* Days above the state standard (calculated): Monitoring for the 24-hour PM10 standard is usually performed once every six days, and the number of days shown exceeding the standard is estimates how many days concentrations would have been over the standard.

Respirable Particulate Matter

Respirable particulate matter (PM10) can be emitted directly by a range of sources, including combustion of any fossil fuel, and it can be formed many miles downwind when various precursor pollutants interact in the atmosphere.

Given the right meteorological conditions, gaseous emissions of pollutants like NOx, SOx, and VOC from combustion sources, and ammonia from agriculture, waste-water treatment, or NOx control equipment, can form particulate matter composed of nitrates

(NO_3^-), sulfates (SO_4^{2-}), and organics. These pollutants are known as secondary particulates, because they are not directly emitted, but are formed through complex chemical reactions in the atmosphere. Particulate nitrate can be formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. In urbanized areas, the nitrate ion concentrations can be a significant portion of the total PM10. Nitrate ions are only one component of particulate nitrate, which typically takes the form of ammonium nitrate or sodium nitrate.

Secondary particulates are probably a minor fraction of the overall PM10 concentrations in the project area because there are few major sources of precursors. In the desert, wind blown dust contributes to elevated PM10 concentrations. This means that the make-up of ambient particulate matter in the project area on the days of highest concentrations is largely of a geologic or mineral nature.

AIR QUALITY Table 3, above, shows that the Mojave Desert Air Basin experiences ongoing violations of the state 24-hour PM10 standard. The less-stringent federal standards have not recently been violated by ambient PM10 concentrations. Historic violations of federal PM10 standards in the Mojave Desert Planning Area (San Bernardino County) led the MDAQMD to prepare a PM10 attainment plan in 1995. The plan attributed the violations to a heavy concentration of fugitive dust sources near the urbanized areas and large-scale high wind events. Public unpaved roads were identified as a significant category of dust emissions in the planning area warranting control (MDAQMD 1995).

Fine Particulate Matter

The U.S. EPA first identified ambient air quality standards for fine particulate matter (PM2.5) in 1997, and most PM2.5 ambient air quality monitors began delivering information around 2000. Region-specific PM2.5 ambient air quality attainment plans, if needed, are due to the U.S. EPA in 2008. The MDAQMD does not need to develop an air quality management plan for PM2.5 because the Mojave Desert Air Basin was designated in 2004 as an area that is either unclassified or attains both the state and federal PM2.5 standards.

Preliminary data is available for PM2.5 from monitoring stations in Victorville starting in 1999. The maximum 24-hour concentrations occurring between 1999 and 2003 was 38.0 $\mu g/m^3$. Compared to the 1997 U.S. EPA standard of 65 $\mu g/m^3$, this area would not exceed the federal standard (CARB web site, accessed Feb. 2005). The highest annual average concentration for 1999 through 2003 was 13.9 $\mu g/m^3$. Compared to the 1997 U.S. EPA standard of 15 $\mu g/m^3$, this area would not exceed the federal standard. Because a three-year data record of concentrations exceeding the standard is necessary to qualify for nonattainment status, the Mojave Desert is an attainment area despite having one year of recent data exceeding the state standard of 12 $\mu g/m^3$.

Concentrations of PM10 and PM2.5 in the Mojave Desert are weakly seasonal, with higher PM2.5 concentrations normally occurring in the winter (CARB CD-R 2002, and Almanac 2001). High PM10 concentrations from wind blown dust can occur during any time of the year. Managing PM2.5 concentrations will require the air district to identify

controllable sources and develop feasible source management strategies. Because PM10 includes PM2.5 as a subset and reactive precursors that lead to ozone can also lead to PM2.5, the established strategies for controlling PM10 and ozone precursors (including existing programs for combustion sources) also presently help to reduce PM2.5 concentrations.

PROJECT DESCRIPTION AND EMISSIONS

This section describes the project design, project emissions, and air pollutant control devices as described in the BEP II AFC (BEP II 2002d).

CONSTRUCTION PHASE

Project Site

BEP II will be located adjacent to BEP I, a power plant of substantially similar design. BEP I was certified by the Energy Commission on March 21, 2001, and began commercial operation on December 29, 2003. BEP II project construction, from site preparation and grading to commercial operation, will require approximately 18-22 months, while the onsite construction schedule requires a total of approximately 16 months. Construction equipment use estimates are based on 6 days per week, 8 hours per day (BEP II, AFC Appendix 7.7-E). Additional construction shifts may be necessary to make up schedule deficiencies. During the commissioning phase, some activities will continue 24 hours per day, 7 days per week (BEP II, AFC p. 2-31).

During construction, approximately 12.4 acres (BEP II, AFC Figure 2.0-24) of the 152-acre parcel (BEP I/BEP II), around the BEP II power island, would be disturbed for temporary construction equipment laydown and parking. Approximately one-half of the total area, or 76 acres, would be disturbed due to construction activities for the power plant and ancillary facilities (note: the cultural avoidance area would not be disturbed). Upon completion of the facility, the BEP II power island will occupy about 15-acres of land near the southern portion of the expansion site.

Linear Facilities

BEP II requires no offsite linear facilities that are in addition to the approved BEP I offsite linear facilities (e.g. transmission line and natural gas pipelines), because of its location to BEP I and its ability to share linear facilities. The transmission interconnection will be to the adjacent Buck Boulevard Substation.

Project Construction Emissions

During the construction period, emissions will be generated from the exhaust of the heavy equipment and fugitive dust from earthwork and activity on unpaved surfaces. Heavy equipment would include loaders and haul trucks to deliver construction materials, excavators and backhoes for earthwork, graders, cranes, lifts, and smaller equipment such as welders, generators, and air compressors. Fugitive dust emissions will occur due to activity on the exposed surfaces at the site, especially those portions that are unpaved.

AIR QUALITY Table 4 summarizes the different levels of criteria pollutants that are estimated to be generated from the 16-month construction phase for BEP II (BEP II 2002d, AFC Table 7.7-19).

The construction equipment and fugitive dust emissions provided above were based on emission factors and load factors published by the U.S. EPA (U.S. EPA, 1991 and 2000). The equipment emission rates assume use of California-required low-sulfur diesel fuel and engines that comply with U.S. EPA off-road equipment emission standards from 1996 (BEP II 2002d, AFC p. 7.7-17). The applicant provided the estimated number of operational hours for each piece of equipment throughout project construction outlined in the AFC (BEP II 2002d, AFC Appendix 7.7-E). For equipment, the mitigation measures identified by the applicant include limiting engine idling time,

AIR QUALITY Table 4
BEP II, Estimated Emissions from Construction
(Hourly Maximum Emissions and Total Emissions)

	NOx		PM10		CO		SOx		VOC	
Equipment	(lb/hr)	(ton)	(lb/hr)	(ton)	(lb/hr)	(ton)	(lb/hr)	(ton)	(lb/hr)	(ton)
Onsite Equipment (a)	18.55	10.3	0.83	0.5	3.01	1.9	0.49	0.3	1.11	0.6
Onsite Fugitive Dust (b)	---	---	11.9	6.7	---	---	---	---	---	---

Source: AFC Appendix 7.7-E (BEP II 2002d).

(a) Hourly emission estimates are based on applicant's estimate of total emissions by month (AFC Appendix 7.7-E) divided by 200 hours per month of activity as per applicant's equipment use estimates.

(b) Fugitive dust emissions are based on applicant assessment of 0.156 ton PM10/month/acre with approximately 7.6 acres of the site being worked during any given month or a maximum rate of 1.19 ton PM10/month (AFC Appendix 7.7-E).

shutting down equipment when not in use, and conducting routine preventative maintenance to the manufacturer's specifications (AFC p. 7.7-55). For fugitive dust, emission reductions would be achieved with dust suppression measures specified by the applicant along with those specified in the Energy Commission's Conditions of Certification. The emissions in **AIR QUALITY Table 4** account for the measures the applicant proposes (BEP II 2002b, Data Request #4).

OPERATIONAL PHASE

Equipment Description

The new nominally-rated 520 MW combined cycle power plant would include the following:

- Two Siemens Westinghouse V84.3A F-Class combustion turbine generators (CTGs), each generating approximately 170 MW. Each CTG includes dry low-NOx combustors for NOx reduction. Each CTG would be coupled to a heat recovery steam generator (HRSG) at an estimated maximum capacity of 132 MMBtu/hr with supplemental duct burners and an integral selective catalytic reduction (SCR) system to control NOx emissions.
- Chilled water inlet air cooling system for the CTGs with 4-cell cooling tower (BEP II 2003a).

- One steam turbine generator (STG) capable of generating approximately 180 MW.
- Cooling system for the steam generation system with a surface condenser that is cooled with circulating water from an evaporative cooling tower. The cooling tower would be a linear 8-cell conventional counter-flow mechanical draft design with high-efficiency drift eliminators to minimize drift.
- Aqueous ammonia storage, vaporization, and injection system for SCR.
- Anhydrous ammonia or hydro-chlorofluorocarbon (HCFC) storage system for refrigerant in inlet air cooling system.
- Diesel-fueled fire pump engine (303 hp) for emergency use only.
- Continuous emission monitoring (CEM) system.
- Water Conservation Offset Program (WCOP) that would result in rotational fallowing of agricultural land to offset project water consumption.

Equipment Operation

Fuel for the BEP II combined cycle power plant will be exclusively pipeline-quality natural gas. It is designed to provide a nominally rated output of 520 MW while meeting all applicable emission limitations. Natural gas would be delivered to the site by the natural gas pipeline for the recently-constructed BEP I. BEP II may also utilize additional facilities at the BEP I site. Other BEP I facilities that may be expanded to serve BEP II include the groundwater supply, fire protection facilities and site access roads. The applicant is proposing that water use be offset by the WCOP, which calls for BEP II to fallow land currently used for agricultural purposes (BEP II 2002d, AFC p. 7.13-23 to 27).

Emission Controls

Both of the CTGs will be equipped with dry low-NOx (DLN) combustors followed by SCR. As a reagent, the SCR system relies on use of ammonia vapor injected to the exhaust stream. With this design, the applicant proposed to limit NOx to 2.5 ppmvd at 15% O_2 (based on a 1-hour average), however, a 2.0 ppmvd NOx limit (3-hour) is established by the FDOC (MDAQMD 2004a). The applicant proposed to limit stack emissions of ammonia (known as ammonia slip) to 10 ppmvd at 15% O_2 (3-hour average), except during periods of start-up, shutdown, and malfunction (BEP II 2002d, AFC p. 7.7-28).

Through the use of advanced combustion control, the applicant proposed to achieve CO concentrations of less than 5 ppmvd or 8.4 ppmvd depending on the CTG load. A more stringent 4.0 ppmvd CO limit (based on a 24-hour average) is established by the FDOC, except during periods of startup, shutdown and malfunction. The applicant proposed to design the HRSG to allow a retrofitted installation of an oxidation catalyst in the event that combustion control could not meet the limits established by the permitting process (BEP II 2002d, AFC p. 7.7-36). Combustion control would also be used to achieve VOC emissions less than 1 ppmvd at 15% O_2 (based on a 1-hour average) (BEP II 2002d, AFC p. 7.7-37).

Continuous emission monitors (CEMs) will be installed on the CTG/HRSG exhaust stacks to monitor NOx, CO, and oxygen concentrations to assure adherence with the emission limits. The CEM system will generate reports of emissions data in accordance with permit requirements and will send alarm signals to the control room when the level of emissions approaches or exceeds pre-selected limits.

The exclusive use of pipeline-quality natural gas, a relatively clean-burning fuel, will limit emissions of PM10 and SO_2. Natural gas contains very little noncombustible gas or solid residues and a small amount of reduced sulfur compounds including mercaptan, thus resulting in relatively low emissions of PM10 and SO_2. The applicant anticipates that the supplied natural gas will contain less than 0.5 grains of sulfur per 100 dry standard cubic feet (dscf), which is less than the 1 grain per 100 scf recommended by CARB (AFC p. 7.7-38). The anticipated PM10 emission rate is 6 lb/hr (AFC Table 7.7-20).

The BEP II cooling tower will be equipped with mist eliminators guaranteed by the manufacturer to limit drift to 0.0006 percent. The applicant proposes a total dissolved solids (TDS) limit of 8,190 mg/l, and a maximum water circulation rate of 146,000 gpm for the cooling tower (BEP II, AFC p. 7.7-38). The inlet air chiller will include a cooling tower equipped with mist eliminators that would reduce drift to 0.001 percent. The applicant proposes a maximum water circulation rate of 17,000 gpm (BEP II 2003a, p. 7.7-3). To provide a reasonable worst-case assessment of impacts to ambient air quality, staff assumes that 100 percent of the TDS would be emitted to the ambient air as PM10 (U.S. EPA AP-42 Section 13.4, 1995). The limits established by the FDOC assume that only 50 percent of the TDS qualifies as PM10.

The cooling tower may also cause emissions of small quantities of organic chemicals, if organic compounds are identified in project wells (see Final Decision for BEP I, Soil & Water Condition #10, page 214, March 21, 2001).

The WCOP that the applicant proposes would result in rotational fallowing or permanent retirement of agricultural land in the area. Agricultural operations in the existing conditions cause emissions of farm equipment exhaust and fugitive dust from tilling, planting, fertilizing, and harvesting, which contribute to elevated PM10 concentrations. According to the applicant's proposal, each landowner that participates in the rotational fallowing program would be required to implement erosion control practices, and participation in the WCOP would require implementation of clod forming processes consistent with the Federal Natural Resources Conservation Service (NRCS) Field Office Technical Guides – Conservation Practice Standard, Surface Roughening Code 609 (BEP II 2003b). Involvement and oversight of the NRCS and Palo Verde Irrigation District would ensure that proper conservation practices are utilized on the fallowed lands, and that wind erosion and fugitive dust emissions from the fallow lands would be minimized (BEP II 2002f). Because the WCOP would manage land according to the goals of these soil and water conservation agencies, implementation of the WCOP is not expected to result in any significant net emission changes.

Project Operating Emissions

Operating the major project components will cause emissions of criteria air pollutants. The assumptions used in estimating the emissions here include:

- manufacturer's guaranteed emission factors;
- the facility operating for approximately 8,760 hours per year;
- a range of load conditions (60% to 100%, with or without duct firing) and a range of ambient temperatures (20°F, 59°F, and 95°F);
- typical operating scenarios for estimating daily and annual emissions based on a worst-case day with two hot starts and one cold start and a worst-case year with 186 hot starts, 50 warm starts, and 10 cold starts, based on calculations attached with the FDOC;
- a limit of 3,600 lb of CO per startup for each turbine, based on the experience gained while testing the BEP I CTGs, which are identical to the CTGs proposed for BEP II;
- concurrent and continuous operation of the cooling system and inlet chillers; and
- operation of the diesel-fueled fire water pump engine for 52 hours per year.

Independent staff analysis is used to estimate the maximum emissions from the cooling towers at BEP II. Staff assumes that the maximum anticipated level of total dissolved solids (8,190 ppmw) could be emitted as PM10 (U.S. EPA AP-42 Section 13.4, 1995). The emission tables do not show direct PM2.5 emissions from any source because an established methodology does not exist for quantifying these emissions for all the sources. Although it is known that a substantial portion of the particulate matter formed during combustion qualifies as PM2.5, estimates of PM2.5 emission rates are not available for the other sources.

During normal operation, the plant will start up and shut down periodically. The amount of time that units are shut down defines whether the subsequent startup is a cold, warm or hot start. The applicant notes that different startup times for each combustion turbine depend on the sequence of the startup; the turbine started first requires slightly more time to come up to steady-state. The expected emission rates during startup and shutdown events are summarized in **AIR QUALITY Table 5**.

AIR QUALITY Table 5
BEP II, Startup and Shutdown Emissions (lb/hr or lb/event)

Operational Source – Mode	NOx (lb/hr)	PM10 (lb/hr)	CO (lb/evemt)	SOx (lb/hr)	VOC (lb/hr)
Each CTG/HRSG (typical hr during Cold Start, 3.7 hrs)	106.0	6.1	---	2.1	5.5
Each CTG/HRSG (typical hr during Warm Start, 2.0 hrs)	151.8	5.7	---	2.0	6.4
Each CTG/HRSG (typical hr during Hot Start, 1.2 hrs)	221.2	5.7	---	2.2	7.4
Each CTG/HRSG (lb/event) (typical during any Startup or Shutdown event)	---	---	3,600	---	---
Each CTG/HRSG (typical hr during Shutdown, 0.5 hr)	340.0	6.0	---	2.0	8.0

Source: BEP II 2002d, AFC Appendix 7.7-A, Vendor Startup Data; CO data from CEC 2005g and CEC 2005h.

Emissions during non-startup or shutdown conditions would be fully controlled because all combustion and post-combustion control systems would be operating at a steady state. The anticipated hourly emissions are shown in **AIR QUALITY Table 6**.

AIR QUALITY Table 6
BEP II, Hourly Operational Emissions (lb/hr)

Operational Source	NOx (lb/hr)	PM10 (lb/hr)	CO (lb/hr)	SO_2 (lb/hr)	VOC (lb/hr)
Each CTG/HRSG (@ 20ºF, 80% w/o duct burning)	14.8	6.5	18.0	2.7	4.1
Each CTG/HRSG (@ 20ºF, 100% w/o duct burning)	18.4	6.6	22.4	3.4	5.2
Each CTG/HRSG (@ 59ºF, 80% w/o duct burning)	13.6	6.5	16.6	2.5	3.8
Each CTG/HRSG (@ 59ºF, 100% w/o duct burning)	16.9	6.6	20.5	3.1	4.7
Each CTG/HRSG (@ 59ºF, 100% w/ duct burning)	18.0	7.6	33.2	3.2	6.8
Each CTG/HRSG (@ 95ºF, 80% w/o duct burning)	12.5	6.4	15.2	2.3	3.5
Each CTG/HRSG (@ 95ºF, 100% w/o duct burning)	15.4	6.5	18.7	2.9	4.3
Each CTG/HRSG (@ 95ºF, 100% w/ duct burning)	16.5	7.5	31.3	3.0	6.4
Each CTG/HRSG (3-hour limit established by FDOC)	14.82	6.0	18.04	2.66	2.9
Cooling Tower (8 cells)	---	3.6	---	---	---
Cooling Tower for Inlet Air Chillers (4 cells)	---	0.7	---	---	---
Fire Pump Engine	4.6	0.3	5.7	0.1	0.7

Source: BEP II 2002d, AFC Appendix 7.7-A, Siemens Westinghouse estimated emissions; BEP II 2003a; MDAQMD 2004a; and independent staff assessment for cooling towers.

In order to determine maximum emissions over the course of one typical day or year, it is necessary to examine various startup scenarios in combination with shutdown and normal operation. Assumptions must be made about the frequency of startups or shutdowns although it is impossible to exactly define how often startups will occur. Staff does not propose to place a limit on the number or type of startups each day or year, but the daily and annual emission limits will help serve as a practical constraint. The assumptions leading to the estimates of daily and annual emissions are illustrated above. It is assumed that both CTGs could startup simultaneously.
AIR QUALITY Table 7 summarizes the estimated maximum daily emissions from the project.

AIR QUALITY Table 7
BEP II, Maximum Daily Operational Emissions (lb/day)

Operational Source	NO_x (lb/day)	PM10 (lb/day)	CO (lb/day)	SO_2 (lb/day)	VOC (lb/day)
CTG/HRSG #3	1,495	144	8,577	61	95
CTG/HRSG #4	1,430	144	8,448	59	92
Cooling Tower (8 cells)	---	86.2	---	---	---
Cooling Tower for Inlet Air Chillers (4 cells)	---	16.7	---	---	---
Fire Pump Engine (testing one hour per day)	4.6	0.3	5.7	0.1	0.7
Total, All Sources	2,931	391	17,031	120	188
Facility Limit Established by FDOC	2,924	336	17,016	128	187

Source: FDOC MDAQMD 2004a; and independent staff assessment for cooling towers.

AIR QUALITY Table 8 summarizes the maximum annual emissions from the project based on the assumptions provided above.

AIR QUALITY Table 8
BEP II, Estimated Annual Operational Emissions (tons per year, tpy)

Operational Source	NO_x (tpy)	PM10 (tpy)	CO (tpy)	SO_2 (tpy)	VOC (tpy)
CTG/HRSG #3	101.7	21.2	342.1	9.3	11.3
CTG/HRSG #4	99.9	21.2	342.7	9.3	11.2
Cooling Tower (8 cells)	---	15.7	---	---	---
Cooling Tower for Inlet Air Chillers (4 cells)	---	3.1	---	---	---
Fire Pump Engine (testing 52 hours per year)	0.12	0.01	0.15	0.01	0.02
Total, All Sources	202	61	685	23	25
Facility Limit Established by FDOC	202	61	685	23	25

Source: FDOC MDAQMD 2004a; and independent staff assessment for cooling towers.

Ammonia Emissions

Due to the large combustion turbines used in this project and the need to control NOx 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 NOx; a portion of the ammonia will pass through the SCR and will be emitted unaltered, out the stacks. These ammonia emissions are known as ammonia slip. The applicant has proposed achieving an ammonia slip no greater than 10 ppm. The applicant calculated the maximum emissions of ammonia to be approximately 33 pounds per hour per CTG/HRSG (BEP II 2002d, AFC Appendix 7.7-A). Staff and the applicant anticipate that ammonia slip levels well below 5 ppm would be achievable especially early in the catalyst life (BEP II 2003b). The applicant expects a catalyst life of approximately five years, depending on operating conditions.

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time frame between the completion of the construction and the reliable production of electricity for sale on the market. Normally, during the initial testing during commissioning the post-combustion control systems (the SCR system) may not be fully installed or operational.

The applicant identified the series of tests (BEP II 2002d, AFC Appendix 7.7-N) that would result in greater-than-routine emissions as each unit is commissioned. The sequence of commissioning would be as follows: 1) minimum fuel flow tests (1 day); 2) first fire (2 days); 3) generator protection tests (2 days); 4) initial synchronization (1 day); 5) diffusion burners (3 days); 6) changeover tests (2 days); and 7) premix burners (8 days). These tests would require approximately 300 hours of operations over approximately a two- to four-month period.

Emissions of all pollutants other than NOx and CO would be similar during commissioning to those that would occur under routine conditions. As such, the impacts analysis for initial commissioning only considers NOx and CO for short-term periods. The emissions anticipated by the applicant for the commissioning period are summarized in **AIR QUALITY Table 9**.

AIR QUALITY Table 9
BEP II, Proposed NOx and CO Commissioning Emissions

Commissioning Sources	Pollutant, Averaging Time	Maximum Emissions
CTG/HRSG #3 and #4	NOx, hourly	1,671 lb/hr
	NOx, daily	22,000 lb/day
	CO, hourly	3,700 lb/hr
	CO, daily	44,000 lb/day

Source: BEP II 2002d, AFC Table 7.7-39; MDAQMD 2004a.

Staff anticipates that the applicant would minimize commissioning emissions by limiting the time of each commissioning activity to the shortest duration feasible, consistent with manufacturer's recommendations, because emissions occurring during commissioning would accrue towards the annual limitations imposed by the MDAQMD.

PROJECT IMPACTS

MODELING APPROACH

Air dispersion modeling provides a means of predicting the location and magnitude of the air contaminant impacts of a new emissions source at ground level. The models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for representative ambient meteorological conditions. Model results are often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$). They are an estimate of the concentration of the pollutant emitted by the project that will occur at ground level.

Inputs for the modeling analysis 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 Southern California Edison (SoCal) service center near Blythe for the years 1989 through 1993. Upper air data from Desert Rock, Nevada, approximately 30 miles west of Las Vegas, was also used with the local surface data to form the dispersion model meteorology input file.

The applicant used a regulatory-guideline model approved by the U.S. EPA (Industrial Source Complex, Short-Term, ISCST3 Version 00101) to estimate the impacts of project-related NOx, PM10, CO and SOx emissions. Additionally, the applicant used the Fugitive Dust Model (FDM) for construction fugitive dust emissions. A description of the modeling analysis for operational activities is provided in AFC Section 7.7.8.5, for construction activities is provided in AFC Section 7.7.8.7, and for commissioning activities is provided in AFC Section 7.7.8.10 (BEP II 2002d).

For the 1-hour impacts of NO_2, the applicant provided a refined modeling analysis of NOx using the ozone limiting method (ISC3_OLM, version 96113). This method calculates the maximum NO to NO_2 conversion using ozone concentration files (from Blythe in 1991 and 1992) to determine maximum 1-hour NO_2 concentrations assuming that 10 percent of the exhaust NOx is NO_2 and that, over time, the available ozone allows a 100 percent conversion of the remaining NO to NO_2. This method conservatively predicts high levels NO_2 concentrations because it does not consider mixing or the quantities of ozone consumed in the reaction. The OLM is a method accepted by the U.S. EPA and CARB for 1-hour NO_2 modeling.

The applicant's modeled impacts were added to the available highest ambient background concentrations measured during 1996 to 2003 at the nearest monitoring station (see **AIR QUALITY Table 3** above). 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.

CONSTRUCTION IMPACTS

The applicant provided staff with a modeling analysis of the impacts caused by the construction-related emissions. The modeling incorporates the applicant's construction mitigation measures. Staff reviewed the applicant's modeling analysis and supporting information and concludes that it is adequate.

The results of the construction impacts analyses are presented in **AIR QUALITY Table 10**. The values in **bold** represent values that equal or exceed the relevant air quality standard. Without any project-related impacts, existing background conditions for PM10 exceed the state standard.

AIR QUALITY Table 10
BEP II, Ambient Air Quality Impacts from Construction (µg/m^3)

Pollutant	Averaging Period	Project Impact	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
PM10 (a)	24-hour	62.87	84	147	50	CAAQS	294
	Annual	8.52	24	33	20	CAAQS	163
NO_2 (b)	1-hour	146.7	70	217	470	CAAQS	46
	Annual	10.2	11	22	100	NAAQS	22
CO	1-hour	27.8	2,300	2,328	23,000	CAAQS	10
	8-hour	15.7	1,456	1,471	10,000	NAAQS	15
SO_2	1-hour	4.77	21.0	26	655	CAAQS	4
	3-hour	3.83	21.0	25	1,300	NAAQS	2
	24-hour	1.81	10.5	12	105	CAAQS	12
	Annual	0.37	2.6	3	80	NAAQS	4

Source: BEP II 2002d, AFC Table 7.7-36 and 37, and Appendix 7.7-K and 7.7-L.
(a) Fugitive dust emissions based on applicant analysis using FDM.
(b) NO_2 impacts based on ISC3-OLM analysis.

As indicated in **AIR QUALITY Table 10**, the project construction activities would further exacerbate existing violations of the state PM10 standards, and thus constitute a significant air quality impact for PM10. Additionally, NOx and VOC emissions from construction equipment would react to contribute to existing violations of the ozone standards (see **AIR QUALITY Table 3**) and thus would constitute a significant air quality impact for ozone via ozone precursors. The project's construction activities would not create a new violation of either NO_2, CO, or SO_2 air quality standards, thus impacts from NO_2, CO, and SO_2 emissions are not considered significant.

OPERATION IMPACTS

The following section discusses the ambient air quality impacts that could occur during routine operation throughout the life of the project, including initial commissioning.

Routine Operation Impacts

A refined modeling analysis was performed to identify off-site criteria pollutant impacts from routine operational emissions. Since BEP II is considered a major modification to BEP I, the impact analysis included BEP II emissions and combined emissions from BEP I and BEP II. The impact modeling analysis included startup/shutdown scenarios to determine maximum short-term and annual emission impacts. Short-term emission rates in the model are derived from startup conditions for the combustion turbines, with simultaneous testing of the emergency fire pump engine. Annual emission rates in the model are derived from full-time, full-load operation of the combustion turbines with approximately 400 hours annually in either a startup or shutdown mode and only 72 hours annually of downtime. Staff analyzed the project assuming that PM10 emission rates for the cooling tower sources, including inlet chillers, reflect staff's opinion that 100 percent of cooling tower drift converts to PM10.

The predicted concentrations of the nonreactive pollutants for BEP II and BEP II with BEP I are summarized in **AIR QUALITY Tables 11 and 12**, respectively. The values in bold in the impacts and background columns represent values that equal or exceed the

relevant air quality standard. Without any project-related impacts, existing background conditions for PM10 exceed the state standard.

AIR QUALITY Table 11
BEP II, Ambient Air Quality Impacts from Routine Operation (µg/m^3)

Pollutant	Averaging Period	Project Impact (a)	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
PM10	24-hour	6.19	84	90	50	CAAQS	180
	Annual	0.40	24	24	20	CAAQS	122
NO_2	1-hour (b)	182	70	252	470	CAAQS	54
	Annual	0.29	11	12	100	NAAQS	12
CO	1-hour (c)	4,603	2,300	6,903	23,000	CAAQS	30
	8-hour (c)	663	1,456	2,118	10,000	NAAQS	21
SO_2	1-hour	12.2	21.0	33	655	CAAQS	5
	3-hour	5.97	21.0	27	1,300	NAAQS	2
	24-hour	0.77	10.5	11	105	CAAQS	11
	Annual	0.02	2.6	3	80	NAAQS	3

Source: BEP II 2002d, AFC Table 7.7-32; with independent staff assessment for PM10 emissions from chillers and cooling towers.

(a) All results include fire water pump engine testing and gas turbine startups as part of routine operation.

(b) NO_2 impacts based on ISC3-OLM analysis with CTGs achieving 2.5 ppm (1-hour).

(c) CO impacts based on 3,600 lb/hr or 8,004 lb/day per CTG and ratio of AFC Table 7.7-32.

The modeling results indicate that the project's operational impacts would not create violations of NO_2, CO, or SO_2 standards, but could further exacerbate existing violations of the state PM10 standard. In light of the existing PM10 non-attainment status for the region, the impacts of direct PM10 emissions are considered to be significant and warrant additional mitigation. Secondary impacts caused by reaction of PM10 and ozone precursors are also discussed below.

There is also a potential for PM2.5 impacts to occur because the project would also emit this contaminant and precursors. The magnitude of potential PM2.5 impacts are not quantified here because there is not an established methodology for quantifying PM2.5 emissions from every source and because there is no established method for characterizing the complex interaction of PM2.5 precursors in the ambient air. PM2.5 mitigation could be provided by mitigating combustion-related PM10, which includes PM2.5, and mitigating reactive precursor emissions that can lead to PM2.5. The best available information about the setting indicates that ambient concentrations of PM2.5 probably do not exceed either the state or federal air quality standards. As a result, the project would not likely contribute to any existing PM2.5 violations. Similarly, based on the levels of PM10 and PM2.5 precursor impacts shown above, routine operation of the project is not expected to create any new violations of PM2.5 impacts.

AIR QUALITY Table 12
BEP II with BEP I, Ambient Air Quality Impacts from Routine Operation (µg/m^3)

Pollutant	Averaging Period	Project Impact (a)	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
PM10	24-hour	13.03	84	97	50	CAAQS	194
	Annual	2.19	24	26	20	CAAQS	131
NO_2	1-hour (b)	183	70	253	470	CAAQS	54
	Annual	0.7	11	12	100	NAAQS	12
CO	1-hour (c)	6,065	2,300	8,365	23,000	CAAQS	36
	8-hour (c)	692	1,456	2,148	10,000	NAAQS	21
SO_2	1-hour	12.2	21.0	33	655	CAAQS	5
	3-hour	6.1	21.0	27	1,300	NAAQS	2
	24-hour	0.83	10.5	11	105	CAAQS	11
	Annual	0.04	2.6	3	80	NAAQS	3

Source: BEP II 2002d, AFC Table 7.7-33-A; with independent staff assessment for PM10 emissions from chillers and cooling towers.

(a) All results include fire water pump engine testing and gas turbine startups as part of routine operation.

(b) NO2 impacts based on ISC3-OLM analysis with CTGs achieving 2.5 ppm (1-hour).

(c) CO impacts based on 3,600 lb/hr or 8,004 lb/day per CTG as in CEC 2005h.

The highest modeled 1-hour NO_2 impact for BEP I and BEP II (183 µg/m^3) occurs during the unlikely occasion of testing of the diesel fire pump engines at both sites during one hour of simultaneous startup of all four CTGs. Without the diesel engines, the maximum 1-hour NO_2 impact during startups would be 173 µg/m^3, and the impacts during routine operation would be less. The location of the maximum impact would be near the property line immediately north of the BEP I site, and the maximum impact at the nearest rural residence, approximately 2,750 feet southwest of the BEP II power plant, would be approximately 105 µg/m^3.

The maximum 24-hour PM10 impact for BEP I and BEP II (13.03 µg/m^3) would occur near the BEP I site boundary, immediately north of the cooling tower. Because of the high buoyancy of the CTG and HRSG exhaust, the combustion turbine sources contribute little to the maximum impacts near the project site boundary. The chillers and cooling tower contribute to the elevated PM10 concentrations at the edge of the site. Maximum CTG and HRSG 24-hour PM10 impacts (less than 1 µg/m^3) occur about 0.75 miles (1.2 km) north and east of the site where the terrain rises about 20 meters above the base elevation of the plant. The 24-hour PM10 impacts from operation of all BEP I and BEP II sources at the nearest residences would be approximately 2 µg/m^3.

Secondary Pollutant Impacts

The project's gaseous emissions of NOx, SO_2, VOC, and ammonia are precursor pollutants that can contribute to the formation of secondary pollutants. Each of these can lead to secondary PM10, and NOx and VOC are precursors to ozone. The process of gas-to-particulate conversion is complex and depends on many factors, including local humidity and the presence of other compounds. Currently, there are no agency-recommended models or procedures for estimating nitrate or sulfate formation, and there is no record of data in the project vicinity that establishes the composition of ambient PM10. However, because of the known relationship of NOx and SO_2 emissions to secondary PM10 formation, it can be said that the emissions of NOx and

SO_2 from the project do have the potential (if left unmitigated) to contribute to higher PM10 levels, and possibly PM2.5, in the region.

As identified above, PM10 impacts would be significant due to direct emissions. Secondary impacts would be significant for PM10 and ozone because routine operational emissions of precursor pollutants would contribute to existing violations of the state-level PM10 and ozone standards (shown in **AIR QUALITY Table 3**). Along with mitigation that is appropriate to reduce significant, direct impacts of PM10, additional mitigation for emissions of precursors is appropriate to reduce secondary impacts to PM10 and ozone.

Impacts During Fumigation Conditions

There is the potential that higher short-term concentrations may occur during fumigation conditions. Fumigation normally occurs during the morning hours after sunrise, when the surface air is stable with a low but rising inversion layer. Within a low inversion layer, the air at ground level experiences turbulent vertical mixing (both rising and sinking) of air within a few hundred feet of the ground, which can bring emissions from a stack close to ground level. Fumigation conditions are generally short-term in nature and are only compared to 1-hour or 3-hour standards. The applicant analyzed the air quality impacts under fumigation conditions from the project turbine using the SCREEN3 model (Version 96043). For the fumigation modeling exercise, the applicant combined the emission rates from both CTG/HRSGs at BEP II and modeled them as if they were emitted from a single CTG/HRSG. All pollutants and normal operating conditions were examined. The fumigation impacts are shown in **AIR QUALITY Table 13**.

AIR QUALITY Table 13
BEP II with BEP I, Ambient Air Quality Impacts During Fumigation (µg/m^3)

Pollutant	Averaging Period	Project Impact (a)	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
NO_2	1-hour	112	70	182	470	CAAQS	39
CO (b)	1-hour	1,432	2,300	3,732	23,000	CAAQS	16
SO_2	1-hour	10.7	21.0	31.7	655	CAAQS	5
	3-hour	9.7	21.0	30.7	1,300	NAAQS	2

Source: BEP II 2002d, AFC Table 7.7-38, and Appendix 7.7-M.

(a) All results include BEP II gas turbine startups as part of routine operation, with routine emissions from BEP I.

(b) CO impacts based on 3,600 lb/hr per CTG and ratio of AFC Table 7.7-38.

Impacts During Initial Commissioning

The applicant anticipates that commissioning activities would occur over approximately a two- to four-month period. Only NOx and CO impacts are analyzed here because these are the only criteria pollutants that will be elevated during the commissioning phase over levels that would occur under routine operations. The results of the applicant's modeling analysis are presented in **AIR QUALITY Table 14**.

AIR QUALITY Table 14
BEP II with BEP I, Ambient Air Quality Impacts During Commissioning (µg/m^3)

Pollutant	Averaging Period	Project Impact (a)	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
NO_x	1-hour	205	70	275	470	CAAQS	59
	Annual	0.9	11	11.9	100	NAAQS	12
CO	1-hour	4,544	2,300	6,844	23,000	CAAQS	30
	8-hour	567	1,456	2,023	10,000	NAAQS	20

Source: BEP II 2002d, AFC Table 7.7-40, and Appendix 7.7-N.

(a) All results include BEP II gas turbine startups as part of routine operation, with routine emissions from BEP I.

(b) CO impacts based on 3,600 lb/hr or 8,004 lb/day per CTG and ratio of AFC Table 7.7-40.

Visibility Impacts

An analysis of the project's gaseous emissions impacts on long-range visibility is required under the Federal Prevention of Significant Deterioration (PSD) permitting program. The analysis includes the effects of gaseous emissions (primarily NOx and SO_2) and particulate (PM10 and PM2.5) emissions on visibility impairment in the nearest Federally-designated Class I areas, which are generally national parks, national wildlife refuges, and wilderness areas. The nearest Class I area to BEP II is Joshua Tree National Park, approximately 40 miles (65 km) to the northwest. The applicant used the U.S. EPA model CALPUFF to assess the project's visibility impacts. (This model was also used to determine nitrogen and sulfur deposition rates at the park.)

The results from the CALPUFF modeling analysis for BEP II indicate that the project's maximum impacts to visibility (percent change in light extinction) within the Joshua Tree National Park would be between 1.46 and 2.05 percent depending on the model year analyzed (BEP II 2003d). The analysis was conducted using monthly average relative humidity data. Although it was not required by the modeling protocol, a more refined analysis was also conducted using hourly relative humidity values. The results of the analyses, including the voluntary refined analysis, show impacts from BEP II would be below the established screening level value of five percent. The National Park Service protocol does not require existing sources from BEP I to be included in these analyses for BEP II. Staff however notes that including BEP I sources would result in an impact of approximately two-times the magnitude of BEP II, which would be less than the five percent screening level used by the National Park Service. The project's visibility impacts on Class I areas are therefore considered insignificant (NPS/Codding May 7, 2003).

MITIGATION

Applicant's Proposed Mitigation

Applicant's Construction Mitigation

MDAQMD Rule 403 requires the applicant to limit fugitive dust during the construction phase of a project. To comply with this rule and reduce construction impacts, the applicant proposed a pair of mitigation measures for fugitive dust and equipment exhaust emissions (BEP II 2002d, AFC p. 7.7-54). The applicant's measures include preparing a fugitive dust mitigation plan and requiring construction contractors to

minimize emissions from equipment by limiting the idling time and properly maintaining the equipment. The emission estimates and modeling analysis in this assessment assume successful implementation of proposed dust control measures and modern, well-maintained equipment operating approximately eight hours per day.

Applicant's Operations Mitigation

The BEP II design includes a combination of clean-fuel-firing equipment, emission control devices, and emission reduction credits. The equipment description, equipment operation, and emission control devices are provided in the **AIR QUALITY Project Description**.

Emission Controls

The combustion turbines would limit NOx formed during combustion using dry low-NOx combustors. Compared to steam or water-injection designs, combustors designed for low-NOx firing maintain low temperatures, thus minimizing NOx formation, while thermal efficiencies remain high.

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, a flue gas control system, including a catalyst system, will be installed in the HRSG. The applicant is proposing a selective catalytic reduction system to reduce NOx. The applicant investigated using an oxidizing catalyst system to reduce CO and VOC, but determined that it would not be cost effective and instead proposes to manage these pollutants by controlling the combustion process. The FDOC established emissions limits of 2.0 ppmvd NOx (3-hour average), with 10 ppmvd ammonia slip, 4 ppmvd CO (24-hour average), and 1 ppmvd VOC (1-hour average). If combustion controls fail to achieve the regulatory limits, the plant design includes contingencies to allow future installation of an oxidation catalyst if necessary (BEP II 2002d, AFC p. 7.7-36).

The cooling towers of the steam-cycle cooling system and the inlet air chillers would use drift eliminators to minimize cooling tower drift to 0.0006 and 0.001 percent, respectively, which would minimize the accompanying PM10 emissions.

Emission Offsets

In addition to emission control strategies included in the project design, the applicant would provide emission reductions to offset emissions of PM10, SOx, and ozone precursor pollutants (NOx and VOC). The applicant is required to offset these pollutants by MDAQMD Regulation XIII by obtaining and surrendering sufficient valid emission reduction credits (ERCs). The quantity of ERCs required by Rules 1303 and 1305 and the quantity identified by BEP II are each shown in **AIR QUALITY Table 15**.

AIR QUALITY Table 15
BEP II Emission Offset Requirements and ERC Sources

Offset Requirement, MDAQMD ERC Source	ERC Identification	NOx (tpy)	PM10 (tpy)	SOx (tpy)	VOC (tpy)
BEP I Offset Obligation	(Attributable to BEP II)	0	0	24	24
BEP II Offset Obligation		202	61	23	25
Total BEP II Offset Obligation		**202**	**61**	**47**	**49**
Colorado River Indian Tribe Road Paving - 3,000 ft Lost Lake Road - 5,280 ft Colorado River Road - 1,000 ft Roadrunner Alley	MDAQMD (pending)	0	126	0	0
SoCal Gas Compressor Engines	MDAQMD – 0051	251	0	0	0
Transfer from NOx to VOC		(49)	---	---	49
Transfer from PM10 to SOx		---	(47)	47	---
Total ERCs Identified:		**202**	**79**	**47**	**49**
Sufficient for MDAQMD Requirements?		Yes	Yes, Pending District Review	Yes	Yes

Source: MDAQMD 2004a. FDOC, Tables 7 and 8 (Staff assumes all NOx ERCs from SoCal Gas).

Notes: MDAQMD allows surplus NOx offsets to satisfy VOC obligation, and surplus PM10 to satisfy the SOx obligation (at a 1.0-to-1.0 interpollutant trading ratio).

Confidential filings made by the applicant in April 2003 indicate that up to 250 tpy of NOx ERCs would be used from MDAQMD Certificate Number 0047 (Galati 2003a). The FDOC reflected a revision of this ERC to Certificate Number 0051. These NOx ERCs were created by reducing emissions from numerous large natural-gas fired engines operated by Southern California Gas Company (SoCal Gas) near Blythe. Surplus NOx ERCs would be used to offset VOC emissions through an interpollutant trade. The U.S. EPA originally indicated that interpollutant trades require its approval on a case-by-case basis (U.S. EPA 2002a), but offered no further comments. Staff expects that the proposed trade of NOx ERCs for VOC emissions at an interpollutant ratio of 1-to-1 is acceptable because reductions of NOx are usually more valuable for ozone management than reductions of VOC. Other possible sources for up to 251 tpy of NOx ERCs are identified in the 2004 FDOC, but the information filed to date by the applicant with the Energy Commission indicates that only the SoCal Gas ERC would be used.

The PM10 ERCs would come from the Colorado River Indian Tribe (CRIT), which agreed to allow the applicant to pave Lost Lake Road, Colorado River Road, and Roadrunner Alley (Galati 2003a). Approximately 9,280 linear feet (1.75 miles) of total roadways were identified by the agreement, as shown in **AIR QUALITY Table 15**. This agreement was established in December 2002 and was set to terminate in 2003; however, the applicant has informally indicated that it is still valid. Because the applicant intends to pave the roads just prior to BEP II construction, the application for the PM10 ERC has not yet been submitted to the MDAQMD for evaluation.

The MDAQMD indicates that 126 tpy of PM10 offsets will be obtained by the applicant through this agreement. This level of emission reduction is based on the use of outdated emission factors from the U.S. EPA guidance document AP-42 (Section 13.2.2, September 1998). More recent guidance was made available by U.S. EPA in

December 2003 (U.S. EPA 2003), but the MDAQMD intends to follow the methodology that was in place at the time of the applicant's original proposal for BEP II in 2002. Traffic data from 2002 was used in the applicant's calculation.

The procedure in Rule 1302 requires MDAQMD to follow a procedure for ERC banking in Regulation XIV before the ERC can be registered and used for an ATC. Staff believes that the application for the CRIT road paving ERC, when it is eventually submitted, should follow a calculation method that is current at that time. Using the current AP-42 method in that process would result in a diminished ERC value of approximately 70 tpy, not 126 tpy. Using current traffic data may also affect the quantity. The FDOC attributes 126 tpy to the applicant's proposal even though the ERC has not been established through the procedure in Regulation XIV. Staff believes that proper calculation of historic actual emissions required by Rule 1404 may reveal this shortfall, and that the applicant may eventually need to secure additional offsets to comply with Regulation XIII. Additional offsets could probably come from paving additional CRIT roads. The most recent inventory of roads available from CARB indicates that there are about 36 miles of unpaved roads on tribal lands in this part of Riverside County (CARB 1997). Despite the apparently premature conclusion of the FDOC, staff does not favor the use of outdated guidance in the offset proposal.

The U.S. EPA originally indicated that the road paving ERCs would be invalid and that the MDAQMD must require the applicant to obtain different PM10 ERCs; U.S. EPA also noted that the applicant must be required to provide public notice of valid ERCs before issuing the FDOC (U.S. EPA 2002a). However, no alternative ERCs have been identified, and the proposed ERCs from CRIT have not been subject to any public notice, as required by Rule 1402(B). It is now clear that the MDAQMD supports the use of road paving and that compliance with MDAQMD Regulation XIII would be satisfied without the need for alternative ERCs. The U.S. EPA offered no further comments.

The ERCs of **AIR QUALITY Table 15** would also be used as the applicant's proposed strategy for mitigation under the California Environmental Quality Act (CEQA).

Adequacy of Proposed Mitigation

Adequacy of Construction Mitigation

The effectiveness of the proposed construction mitigation can be expressed by the percentage of uncontrolled emissions that are avoided, and it varies widely due to the number of influencing factors. Some of these factors include: ambient conditions (temperature, wind, and humidity), size and weight of vehicles, vehicle speed, frequency and number of active vehicles, soil characteristics (chemical composition, particle size distribution, organic components), and day-to-day aggressiveness of mitigation efforts (e.g., application of water or dust suppressants, street sweeping to remove carryout from paved roads). If the mitigation measures for fugitive dust-generating activities are applied correctly and with sufficient frequency, the control efficiency can approach 100 percent. Much of the uncertainty is due to varying degrees of vigilance on the part of construction personnel. The applicant presents an analysis of probable impacts that presumes an average fugitive dust mitigation efficiency. The effectiveness of proposed

mitigation for construction equipment emissions also depends largely on the vigilance of construction personnel to operate equipment properly.

As shown in **AIR QUALITY Table 12** above, direct impacts of NO_2, CO, and SO_2 would not be significant. Direct PM10 impacts would be reduced by the proposed mitigation but would remain significant because any increase to PM10 concentrations could contribute to continuing violations of the PM10 standards. Similarly, secondary impacts for PM10 and ozone would continue to be significant because of construction emissions of PM10 and ozone precursors. Additional mitigation is necessary (see **Staff Proposed Mitigation**) to reduce direct PM10 impacts and secondary impacts to PM10 and ozone.

Adequacy of Operations Mitigation

The MDAQMD BACT determinations in the FDOC for gas turbine emissions of 2.0 ppmvd NOx (3-hour basis) and 4.0 ppmvd CO (24-hour basis) are as stringent as those for other recent projects in the jurisdiction of MDAQMD. The requirements are slightly less stringent than the current U.S. EPA and CARB recommendations, which require similar levels of control, with shorter averaging periods (U.S. EPA 2002a, CARB 2002a). For example the Palomar Energy Project and Tesla Power Project, certified by the Energy Commission in 2003 and 2004 are committed to achieving BACT levels of 2.0 ppmvd NOx (1-hour) and 4.0 ppmvd CO (3-hour). Similarly, the FDOC requirement for ammonia slip is inconsistent with comments to MDAQMD from U.S. EPA, which "strongly recommend" a limit of 5 ppm for BEP II (U.S. EPA 2002a) and guidance from CARB (CARB 1999). These agencies indicate that the more-stringent ammonia slip level of 5 ppmvd is achievable, and Energy Commission staff agrees (CEC 2002a). Although the limits proposed in the FDOC would satisfy the MDAQMD requirements, staff believes that additional ammonia control would be feasible and appropriate given the potential for secondary PM10 formation.

The CEQA mitigation approach for PM10, SOx, and ozone precursor pollutants (NOx and VOC) includes emission reductions as shown in **AIR QUALITY Table 15** (above). The reductions serve the dual purpose of satisfying the requirements in MDAQMD Regulation XIII and mitigating the CEQA impacts identified by Energy Commission staff. The CEQA mitigation balance shown in **AIR QUALITY Table 16** differs from the LORS result in **Table 15** in two ways: (1) a smaller offset is provided by the CRIT road paving ERC because the calculation methods used in the LORS analysis are now outdated; and (2) the emission increases attributable to BEP II under CEQA do not need to include BEP I emissions because they are included in the CEQA baseline.

AIR QUALITY Table 16
BEP II Emission Offsets and CEQA Mitigation Balance

Offset Requirement, MDAQMD ERC Source	ERC Identification	NOx (tpy)	PM10 (tpy)	SOx (tpy)	VOC (tpy)
BEP II CEQA Liability	(from Table 8 above)	**202**	**61**	**23**	**25**
Colorado River Indian Tribe Road Paving - 3,000 ft Lost Lake Road - 5,280 ft Colorado River Road - 1,000 ft Roadrunner Alley	MDAQMD (pending) - calculation revised by staff	0	~70	0	0
SoCal Gas Compressor Engines	MDAQMD – 0051	251	0	0	0
Transfer from NOx to VOC and SOx		(49)	---	24	25
Transfer from PM10 to SOx		---	(9)	9	---
Total Mitigation Identified		**202**	**61**	**33**	**48**
Sufficient for CEQA Requirements?		Yes	Yes	Yes	Yes

Source: Independent staff assessment of proposed ERCs.

Notes: Staff proposes to allows surplus NOx offsets to satisfy VOC and SOx obligation, and surplus PM10 to partially satisfy SOx obligation.

Direct PM10 Mitigation

Staff estimates that 61 tpy of direct PM10 emissions must be offset in order for the project to fully mitigate its contribution to state-level nonattainment PM10 conditions. The applicant and MDAQMD identified sufficient CRIT road paving PM10 ERCs in the FDOC to satisfy the fundamental requirements of Rules 1302 and 1303 (**AIR QUALITY Table 15**). However, the 126-tpy quantity of offsets from road paving was estimated by the applicant and MDAQMD using outdated emission factors from AP-42 (U.S. EPA 1998) that staff does not favor. A more accurate depiction of this proposed mitigation would use the most current factors. Applying current emission factors (U.S. EPA 2003), the applicant's road paving proposal would provide only about 70 tpy of PM10 emission reductions (**AIR QUALITY Table 16**). This would be sufficient and effective mitigation for the project's 61 tpy of PM10 emissions, leaving about a 9 tpy surplus of PM10 reductions for interpollutant trading.

The effectiveness of paving dirt roads depends on whether the credits are real, enforceable, surplus, permanent, and quantifiable. The MDAQMD normally determines this as required by Rules 1402 and 1404, but it is not clear from the FDOC whether this review has been completed yet (see **Compliance with LORS** below).

Staff has reservations about using dust control to mitigate impacts from combustion-related particulate matter. Fugitive dust from unpaved public roads is not a source category that is normally subject to permitting in the MDAQMD, but the MDAQMD has used road paving as a source of ERCs for earlier projects (including BEP I). The roads proposed for paving by the applicant and CRIT would probably not otherwise be paved in the future because they are on tribal land. The CARB also previously expressed specific concerns about using road paving offsets for combustion sources in a memorandum from the CARB Executive Officer to all local Air Pollution Control Officers (CARB 2000b). CARB noted that combustion of natural gas emits very fine particulate matter less than 2.5 microns in size (PM2.5), and dust control from road paving

provides reduction of particles much larger in size, the majority PM10, with only 13 to 15 percent of the emission reductions being less than 2.5 microns (EPA 1991, AP-42 Section 13.2.2). In other cases staff has recommended correcting the ERC for PM10-to-PM2.5 effectiveness because only about 15 percent of the PM10 reduction would qualify as PM2.5. Staff's analysis of BEP II impacts reveals that the project would not be likely to cause new PM2.5 violations or contribute to PM2.5 violations, because there is no evidence of a PM2.5 attainment problem in the setting. The PM2.5 effectiveness of the road paving ERC is less important in this setting, and the PM10 reductions achieved by road paving would be suitable for mitigating the PM10 impacts of the project. It is worth noting that the MDAQMD supports use of road paving PM10 reductions as a means of offsetting the PM10 from natural gas combustion (MDAQMD 1995 and 2004a).

Secondary PM10 Mitigation

It is difficult to correlate the effect of gaseous emissions on particulate formation because of the complexity of the precursor reactions. Because MDAQMD requires offsets for project emissions of NOx and SOx, staff expects that compliance with the offset requirements would satisfactorily mitigate the effects of these precursors as long as sufficient offsets are available. The applicant proposes to use interpollutant trading to offset project emissions of SOx.

Staff estimates that approximately 23 tpy of SOx emissions (**AIR QUALITY Table 8**) must be offset in order for the project to fully mitigate the secondary effects of PM10 formation from BEP II. The project's NOx and VOC emissions are also PM10 precursors warranting offsets, as described below. The applicant offers PM10 emission reductions from road paving as mitigation, and staff believes that a surplus of approximately 9 tpy of PM10 reductions would remain after mitigating the direct PM10 impacts (see above discussion). The setting indicates that secondary particulates are probably a minor fraction of the overall PM10 concentrations in the area, and wind blown dust is more of a PM10 concern than gas-to-particulate conversion. PM10 reductions from road paving are more valuable in this setting than they would be in other areas, where close management of precursors is more desirable. The MDAQMD uses a 1-to-1 ratio to trade PM10 reductions for SOx increases. The U.S. EPA has not provided any guidance on appropriate interpollutant trading ratios for this case, probably because the area attains the federal ambient standards for PM10. With this ratio, the PM10 ERCs would offset 9 tpy of the project's 23 tpy of SOx emissions, meaning another approach is needed to mitigate a portion of the SOx emissions. Additional mitigation is also required to ensure that project emissions of ammonia would cause insignificant impacts to secondary PM10 formation.

Secondary Ozone Mitigation

The applicant proposed providing offsets of NOx to mitigate secondary ozone impacts. The ability of the offsets to mitigate project ozone impacts depends on whether sufficient combined reductions of NOx and VOC (precursor organic compounds) would occur. The applicant and the FDOC identify that a sufficient quantity of NOx ERCs would be surrendered, see **AIR QUALITY Table 15** above.

Staff estimates that 202 tpy of NOx emissions would be fully offset with the surrender of the 251-tpy SoCal Gas ERC. About 49 tpy of excess NOx reductions would also be available for an interpollutant trade to offset the VOC increases of the project at a 1-to-1 ratio. As with the PM10 mitigation strategy, the U.S. EPA has not provided any guidance on interpollutant trading ratios, probably because the area attains the federal ozone standards. Existing ozone concentrations around Blythe are likely lower than those measured in Twentynine Palms (BEP II 2002d), and data from Yuma indicates that ozone concentrations probably comply with the most restrictive standards (ADEQ 2001).

Staff estimates that approximately 25 tpy of VOC emissions (**AIR QUALITY Table 8**) must be offset in order for the project to fully mitigate the ozone precursor effects. After applying the 49-tpy excess NOx reductions from above, staff believes that a surplus of approximately 24 tpy of NOx reductions would remain after full mitigation of the VOC impacts. There is not enough information on the local air quality to develop case-specific interpollutant trading ratios and determine the precise benefit that would occur with the surplus NOx reductions, but some level of additional mitigation of both secondary ozone and PM10 impacts would occur. The unique nature of the BEP II location (isolated from many other sources of precursor pollutants), area meteorology (extremely low humidity), and ambient air quality (attains all federal standards) precludes close management of the various precursors. Staff notes that a site-specific approach is necessary for any proposal to offset impacts through interpollutant trading, and in any locality with a federal nonattainment designation, case-by-case review of interpollutant trades between precursors would need to be conducted by the local air district or U.S. EPA [e.g., Rule 1305(B)(6)(c)]. Because NOx is a precursor of PM10, as well as ozone, staff believes that in this setting, the 24-tpy surplus of NOx reductions would adequately offset the residual 14-tpy SOx impacts (identified above), eliminating the need for further criteria pollutant offsets.

Staff Proposed Mitigation

Staff Proposed Construction Mitigation

Staff proposes specific mitigation to reduce construction emissions of PM10, VOC, and NOx to avoid PM10 and ozone impacts. Much of the uncertainty in the effectiveness of the applicant's proposed strategy for construction mitigation is due to varying degrees of vigilance on the part of construction personnel. Coordination of the measures would be by personnel specifically approved by the Energy Commission as the Air Quality Construction Mitigation Manager (**AQ-SC1**). Staff's proposed Condition of Certification **AQ-SC2** would require the applicant to prepare and adhere to an Air Quality Construction Mitigation Plan. The plan would need to address how dust control would occur (**AQ-SC3**), how the Construction Mitigation Manager would respond to plumes of dust (**AQ-SC4**), and strategies for minimizing emissions from diesel-fueled engines (**AQ-SC5**). Because SO_2 is also a precursor to PM10, one aspect of the plan would require use of ultra-low sulfur diesel fuel. These measures also involve monthly reporting and monitoring of certain environmental parameters to indicate whether a high degree of day-to-day vigilance is being maintained. The conditions have been revised and updated by staff since the time of the Preliminary Staff Assessment and the BEP I

decision to improve the effectiveness of the mitigation and to incorporate staff's evolving experience in implementing similar measures for other project owners.

With the implementation of the staff-recommended construction mitigation measures, the PM10 and ozone impacts from the construction of BEP II can be reduced to a level of insignificance.

Staff Proposed Operations Mitigation

Staff reviewed the overall approach to mitigation, including the emission control systems proposed for the sources and the project-specific offset package submitted in 2003. When the proposed offsets are taken together in the ambient setting, staff believes that the project's emissions of NOx, PM10, SOx, and VOC would be fully mitigated by the proposed offsets. To ensure full mitigation of PM10 and ozone impacts with the proposed ERCs, staff recommends a condition (**AQ-SC9**) to assure that the proposed offsets will be acquired.

Mitigation of secondary PM10 impacts also depends partially on managing ammonia emissions. The ammonia slip that would be in the exhaust after passing through the SCR catalyst system could react with SOx and NOx in the ambient air to form ammonium sulfate and ammonium nitrate, which are components of PM10 and PM2.5. As proposed, BEP II would contribute between 200 and 300 tons per year of ammonia. The reactivity can be enhanced with available nitrate and sulfate precursors, high humidity, and mild ambient temperatures. Because there are few sources of SOx and NOx near Blythe and because periods of high humidity are extremely rare in Blythe, staff expects only a weak tendency for secondary particulate matter to form from project ammonia emissions. Mild temperatures enhancing ammonia-to-particulate conversion would generally occur during the winter months, when PM2.5 concentrations in the desert tend to be higher (CARB 2001). The applicant provided comments indicating the area is presently saturated with ambient ammonia; however, no data is available to establish the role of ammonia as a precursor in this area or the existing composition of ambient PM10. Although staff does not anticipate a strong correlation between the project's ammonia emissions and ambient particulate impacts, staff does expect that the applicant will control its ammonia slip emissions to the extent feasible, while maintaining the required NOx emission limit, to reduce the operational costs of ammonia loss.

Energy Commission staff experience and vendor guarantees show that ammonia slip below 5 ppmvd at 15% O_2 is achievable (CARB 1999), and comments to MDAQMD from U.S. EPA strongly recommended the 5 ppm limit for BEP II (U.S. EPA 2002a). Because the project proposes to achieve an ammonia slip limit of 10 ppm, it would not be consistent with U.S. EPA or CARB recommendations. It is also possible that increased ammonia emissions could contribute to increased secondary PM10, which could contribute to existing violations of the PM10 CAAQS, especially because of the presence of SOx and NOx or nitric acid from BEP I and BEP II. The applicant has noted that levels well below 5 ppm can be expected early in the roughly 5-year catalyst life with gradual increases occurring as the catalyst ages (BEP II 2003b). In response to the U.S. EPA recommendations for BEP II and to fully mitigate potential PM10 impacts, staff recommends mitigation (**AQ-SC10**) that would require the project to replace, repair, or recondition this system if slip levels persistently exceed 5 ppmvd.

GREENHOUSE GAS EMISSIONS REPORTING

In addition to regulated criteria pollutants, the combustion of natural gas produces air emissions known as greenhouse gases. These include primarily carbon dioxide (CO_2) and methane (unburned natural gas). Greenhouse gases are known to contribute to the warming of the earth's atmosphere. Climate change from rising temperatures represents a risk to California's economy, public health, and environment due to changes in sea levels that could lead to flooding of coastal communities, drought, forest fires, decline of fish populations, reduced hydropower opportunities, and loss of habitat. In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p.5). In the 2003 Integrated Energy Policy Report, the Energy Commission recommended that the state should require reporting of greenhouse gas emissions as a condition of state licensing of new electric generating facilities (CEC 2003, p. 42). Staff recommends Condition of Certification **AQ-SC11** which requires the project owner to report the quantities of carbon dioxide emitted as a result of facility operation. Such reporting would be done in accordance with accepted reporting protocol as specified.

CUMULATIVE IMPACTS

The cumulative impact analysis identifies any stationary sources within a 6-mile radius of the project that could interact with the project's emissions. These include any source that will soon be or was in the permitting process at the time, or that had received a construction permit from the MDAQMD but was not yet operational. Emissions from other existing stationary sources within the 6-mile radius are normally presumed to be included in the existing background air quality conditions. Sources beyond the 6-mile radius are presumed to cause minimal effects at the project site.

The applicant found no sources in the area that fit these criteria (BEP II 2002d, AFC p. 7.7-46). The area was also investigated for other large sources, such as large stationary internal combustion engines for agricultural purposes, and none were found. The Southern California Gas Compressor Station in Blythe was voluntarily included by the applicant in their modeling analysis although it does not fit the criteria for being a cumulative project. It is worth noting that recent modifications at the compressor station would reduce emissions from that source compared to historic conditions. The modeling analyses for BEP II included BEP I, and these results are presented in **AIR QUALITY Table 12**, above.

Multiple new transmission lines are currently being proposed in the Blythe area by the Imperial Irrigation District (IID), Southern California Edison (SCE), and the operators of BEP I. These new transmission lines would not include any permanent, stationary sources of air pollution. Therefore, including them in the cumulative air quality assessment for BEP II would not affect the results presented in **AIR QUALITY Table 12**. Construction emissions caused by the transmission projects would be short-term and would be distributed over the length of each project. As such, they would not be expected to substantially overlap with BEP II project emissions. To address the cumulative impacts of the IID line, Energy Commission staff provided a letter to IID July 2, 2003 with recommendations for IID to incorporate specific construction-related mitigation measures.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is more than 50 percent within a six-mile radius of the proposed BEP II (please refer to **Socioeconomics Figure 1** in this FSA). Staff also reviewed Census 2000 information that shows the low-income population is less than fifty percent within the same radius.

The air quality analysis for ozone and PM10 impacts depends on an offset package that staff has analyzed and incorporated with Condition of Certification **AQ-SC7**. If the final mitigation recommended by staff is not acceptable to the applicant, the impacts could remain partially unmitigated and environmental justice may need to be further evaluated.

COMPLIANCE WITH LORS

FEDERAL

The U.S. EPA is responsible for completing the Federal Prevention of Significant Deterioration (PSD) review requirements. Review under the PSD program has not been completed by U.S. EPA; consultation with the U.S. Fish and Wildlife Service was still ongoing in 2003. To achieve compliance with the PSD program, the project must satisfy requirements for BACT, defined by the U.S. EPA. Although the U.S. EPA has not formally released a determination of PSD requirements, their comments on the MDAQMD Preliminary Determination of Compliance in 2002 (U.S. EPA 2002a) led to the more stringent limits on NOx and CO of the 2004 FDOC. Based on the BACT determination in the FDOC, staff expects that BEP II would satisfy the U.S. EPA BACT requirements without substantial additional modification.

Because the federal permitting process is ongoing, and there remains a possibility of revised conditions, staff recommends a condition of certification for coordinating future possible modifications (**AQ-SC6**).

In early March 2005, BEP II indicated that a modification to the current draft PSD permit would be requested to address startup emissions. The modification could likely be processed with a public notice period within 90 days of submittal to U.S. EPA. Until U.S. EPA involvement is complete, staff cannot make a recommendation as to whether the project is likely to comply with PSD requirements.

STATE

Staff believes that if the project meets the U.S. EPA recommendations for BACT, the project would demonstrate compliance with California State Health and Safety Code, Section 41700.

Under the Warren-Alquist Act, Public Resources Code Section 25523(d)(2), the Energy Commission may not find that the proposed facility conforms with applicable air quality standards unless the MDAQMD certifies that complete offsets have been identified and will be obtained. Although staff does not favor the calculation method used by the applicant and MDAQMD for the proposed CRIT road paving PM10 offsets, the

MDAQMD has determined that a sufficient quantity of offsets have been identified and that the offsets will be obtained.

LOCAL

The MDAQMD completed a Final Determination of Compliance (FDOC, MDAQMD 2004a) for this project on May 3, 2004 and found that BEP II, after application of the proposed permit conditions, would comply with all MDAQMD Rules and Regulations. It is worth noting that the ATCs attached with the FDOC show an expiration date of January 31, 2005; however, the Energy Commission decision supersedes all other state and local permits including the ATCs. With staff's recommended revisions to the conditions (described below), the information reflected in the ATCs would be current, making the expiration date irrelevant.

Energy Commission staff believes that the project equipment should be required to achieve the startup and shutdown emission levels similar to the limits recently established at BEP I (CEC 2005h). After completing performance testing, BEP I stated that the original startup and shutdown emission limits for CO were based on incorrect information from the turbine manufacturer and are not achievable (CEC 2005g). Because of the identical turbines, this issue would affect BEP II. The MDAQMD is aware of the changes needed to the BEP II conditions and agrees that they need to be modified, but the MDAQMD has not acted because the BEP II applicant has not requested the modification.

The applicant informally agreed during a workshop in January 2005 to allow Energy Commission staff to update the FDOC conditions based on the experience gained while testing the BEP I CTGs. These revisions are shown in strikeout style. Staff recommends changes to FDOC conditions in **AQ-5**, **AQ-6**, and **AQ-36**. Administrative requirements of the New Source Review rules (Rule 1306, discussed below) may require MDAQMD to revise the FDOC to match staff's recommendations.

RULE 1302 and REGULATION XIV – PROCEDURES, NEW SOURCE REVIEW, OFFSETS

Compliance with Rule 1302(C)(3)(b) requires the MDAQMD to determine whether all of the proposed offsets are real, enforceable, surplus, permanent, and quantifiable. Regulation XIV (including Rules 1402 and 1404) requires the applicant to prepare an application for each proposed ERC, and it requires the MDAQMD to undergo a public notification process for each ERC that involves CARB and U.S. EPA. Also, a case-by-case review of interpollutant trades between precursors must be conducted [Rule 1305(B)(6)(c)]. Each of these rules are federally-enforceable components of the NSR program (61 FR 58133 and 62 FR 3215), and the U.S. EPA previously identified deficiencies in the implementation of these rules on the BEP II case (U.S. EPA 2002a).

No ERC application for the proposed PM10 offsets has been submitted by the applicant, and staff has identified shortcomings in the proposed PM10 offset package. It is not clear from the FDOC whether the MDAQMD has analyzed the proposed PM10 offsets in sufficient detail to determine whether the ERCs are real, enforceable, surplus, permanent, and quantifiable, and it is not clear if a case-by-case review of the proposed interpollutant trades has occurred. Staff believes that the review required by Rule

1302(C)(3)(b) and Regulation XIV must still be completed and that a need for additional ERCs may eventually be identified by the MDAQMD when this occurs. To ensure LORS conformance, staff's recommended condition (**AQ-SC9**) would require the applicant to demonstrate that the MDAQMD has determined that the ERCs are real, enforceable, surplus, permanent, and quantifiable, as required by these rules.

RULE 1306 – ELECTRIC ENERGY GENERATING FACILITIES

The Conditions of Certification recommended by staff here have been revised from the FDOC conditions based on staff's desire to reflect the results of emissions tests from the identical BEP I (CEC 2005h). Staff's proposed revisions address CO emissions during startup. If staff's Conditions of Certification are adopted as recommended, the Energy Commission decision would not include all conditions of the 2004 FDOC verbatim. However, because Rule 1306 is primarily administrative in nature, and staff expects MDAQMD to agree with the suggested changes, staff does not believe that the modifications rise to the level of LORS nonconformance.

FACILITY CLOSURE

Eventually, BEP II 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, all sources of air emissions would cease, and impacts associated with those emissions would no longer occur. The only other expected emissions would be construction/demolition emissions from the dismantling activities. Staff recommends that a Facility Closure Plan be submitted to the Energy Commission Compliance Project Manager to demonstrate compliance with all local, state, and federal rules and regulations during closure and demolition.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

No written comments concerning air quality in the Preliminary Staff Assessment were received from either the public or from any public agency. Comments made by agencies to the MDAQMD have been noted, where appropriate. Comments received during the January 26, 2005 workshop were discussed in the workshop and have been incorporated in this Staff Assessment.

CONCLUSIONS AND RECOMMENDATIONS

Staff has reviewed the applicant's documentation and the FDOC issued by the MDAQMD and concludes that the BEP II project, with the recommended Conditions of Certification, would not cause significant air quality impacts.

Staff expects that anticipated actions by MDAQMD will lead BEP II to conform with all applicable LORS. It is not presently clear from the FDOC whether the MDAQMD has analyzed the proposed PM10 offsets in sufficient detail, and staff believes that a need for additional ERCs may eventually be identified by the MDAQMD when the review required by Rule 1302(C)(3)(b) and Regulation XIV is completed. If future review reveals a shortfall in ERCs, staff believes that the applicant should be able to secure

additional ERCs by paving other roads on tribal lands. Conformance with LORS would be likely when the MDAQMD certifies the proposed PM10 ERCs pursuant to the provisions of Regulation XIV and incorporates the staff-recommended changes to the FDOC conditions.

CONDITIONS OF CERTIFICATION

STAFF CONSTRUCTION CONDITIONS

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with conditions **AQ-SC3**, **AQ-SC4** and **AQ-SC5** for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM Delegates. The AQCMM and AQCMM Delegates shall have full access to all areas of construction on the project site and linear facilities, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM Delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the CPM.

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM Delegates. The AQCMM and all Delegates must be approved by the CPM before the start of ground disturbance.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with conditions **AQ-SC3**, **AQ-SC4** and **AQ-SC5**.

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report (MCR) that demonstrates compliance with the following mitigation measures for the purposes of preventing all fugitive dust plumes from leaving the Project. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

a) All unpaved roads and disturbed areas in the project and linear construction sites shall be watered as frequently as necessary to comply with the dust mitigation objectives of **AQ-SC4** (the prevention of fugitive dust plumes). The frequency of watering can be reduced or eliminated during periods of precipitation.

b) No vehicle shall exceed 10 miles per hour within the construction site.

c) The construction site entrances shall be posted with visible speed limit signs.

d) All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

e) Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

f) All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

g) All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

h) Construction areas adjacent to any paved roadway shall be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent run-off to roadways.

i) All paved roads within the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

j) At least the first 500 feet of any public roadway exiting from the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff from the construction site is visible on the public roadways.

k) All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or shall be treated with appropriate dust suppressant compounds.

l) All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.

m) Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

Verification: The project owner shall include in the MCR (1) a summary of all actions taken to maintain compliance with this condition, (2) copies of any complaints filed with the air district in relation to project construction, and (3) any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM or an AQCMM Delegate shall continuously monitor the construction activities for visible dust plumes.

Observations of visible dust plumes that have the potential to be transported (1) off the project site or (2) 200 feet beyond the centerline of the construction of linear facilities or (3) within 100 feet upwind of any regularly occupied structures not owned by the project owner indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM or Delegate shall direct implementation of additional methods of dust suppression if step 1 specified above fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM or Delegate shall direct a temporary shutdown of the activity causing the emissions if step 2 specified above fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, provided that the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified.

AQ-SC5 Diesel-Fueled Engines Control: The AQCMM shall submit to the CPM, in the Monthly Compliance Report (MCR), a construction mitigation report that demonstrates compliance with the following mitigation measures for the purposes of controlling diesel construction-related emissions. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

a) All diesel-fueled engines used in the construction of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur.

b) All diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

c) All construction diesel engines, which have a rating of 100 hp or more, shall meet, at a minimum, the Tier 1 California Emission Standards for Off-Road Compression-Ignition Engines as specified in California Code of Regulations, Title 13, section 2423(b)(1) unless certified by the on-site AQCMM that such engine is not available for a particular

item of equipment. In the event a Tier 1 engine is not available for any off-road engine larger than 100 hp, that engine shall be equipped with a catalyzed diesel particulate filter (soot filter), unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is "not practical" if, among other reasons:

(1) There is no available soot filter that has been certified by either the California Air Resources Board or U.S. Environmental Protection Agency for the engine in question; or

(2) The construction equipment is intended to be on-site for ten (10) days or less.

(3) The CPM may grant relief from this requirement if the AQCMM can demonstrate that they have made a good faith effort to comply with this requirement and that compliance is not possible.

d) The use of a soot filter may be terminated immediately if one of the following conditions exists, provided that the CPM is informed within ten (10) working days of the termination:

(1) The use of the soot filter 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 backpressure.

(2) The soot filter is causing or is reasonably expected to cause significant engine damage.

(3) The soot filter is causing or is reasonably expected to cause a significant risk to workers or the public.

(4) Any other seriously detrimental cause which has the approval of the CPM prior to the termination being implemented.

e) All heavy earthmoving equipment and heavy duty construction related trucks with engines meeting the requirements of (c) above shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

f) All heavy construction equipment with engines meeting the requirements of (n)(3) above shall not remain running at idle for more than five minutes, to the extent practical.

Verification: The project owner shall include in the MCR (1) a summary of all actions taken to maintain compliance with this condition, (2) copies of all diesel fuel purchase records, (3) a list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that equipment has been properly maintained, and (4) any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC6 The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. EPA, and any revised permit issued by the District or U.S. EPA for the project.

Verification: 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.

STAFF OPERATIONS CONDITIONS

AQ-SC7 The project owner shall submit Quarterly Operational Reports to the CPM and District that include operational and emissions information as necessary to demonstrate compliance with Conditions **AQ-SC10** and **AQ-SC11**, and **AQ-1** through **AQ-54**, as applicable. The Quarterly Operational Report will specifically note or highlight instances of noncompliance and the corrective measures taken to correct these incidents.

Verification: The project owner shall submit the Quarterly Operational Reports to the CPM and the District no later than 30 days following the end of each calendar quarter.

AQ-SC8 The project owner shall comply with all staff (**AQ-SC**) and District (**AQ**) Conditions of Certification. The CPM, in consultation with the District, may approve any change to a Condition of Certification regarding air quality, as an insignificant change, provided that: (1) the project remains in compliance with all applicable laws, ordinances, regulations, and standards, (2) the requested change clearly will not cause the project to result in a significant environmental impact, (3) no additional mitigation or offsets will be required as a result of the change, (4) no existing daily, quarterly, or annual permit limit will be exceeded as a result of the change, and (5) no increase in any daily, quarterly, or annual permit limit will be necessary as a result of the change.

Verification: The project owner shall notify the CPM in writing of any proposed change to a condition of certification pursuant to this condition and shall provide the CPM with any additional information the CPM requests to substantiate the basis for approval.

AQ-SC9 The project owner shall surrender the emission offset credits listed below or a modified list, as allowed by this condition, at the time that surrender is required by condition **AQ-18**. The ERC list shall contain evidence that the MDAQMD has determined that the ERCs are real, enforceable, surplus, permanent, and quantifiable. The project owner may request CPM approval for any substitutions or modification of credits listed below. The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws,

ordinances, regulations, and standards, the requested change(s) clearly will not cause the project to result in a significant environmental impact, and each requested change is consistent with applicable federal and state laws and regulations.

MDAQMD ERC Source	ERC Identification	NOx (tpy)	PM10 (tpy)	SOx (tpy)	VOC (tpy)
Colorado River Indian Tribe Road Paving - 3,000 ft Lost Lake Road - 5,280 ft Colorado River Road - 1,000 ft Roadrunner Alley	MDAQMD (pending)	0	126	0	0
SoCal Gas Compressor Engines	MDAQMD – 0051	251	0	0	0

Note: MDAQMD allows interpollutant trading of NOx and PM10 ERCs to fully offset VOC and SOx, respectively.

Verification: The project owner shall submit to the CPM a list of ERCs to be surrendered to the District at least 60 days prior to initial startup. If the CPM, in consultation with the District, approves a substitution or modification, the CPM shall file a statement of the approval with the commission docket and mail a copy of the statement to every person on the post-certification mailing list. The CPM shall maintain an updated list of approved ERCs for the project.

AQ-SC10 The ammonia slip shall not exceed 10 ppmv @ 15 percent O_2 averaged over one hour. The SCR ammonia injection grid shall be replaced, repaired or otherwise reconditioned within 12 months of the ammonia slip reaching 5 ppm @ 15 percent O_2 averaged over 24 hours with the following provision. The SCR ammonia injection grid replacement, repair or reconditioning scheduled event shall be canceled if the project owner can demonstrate to the CPM that, subsequent to the initial exceedance, the ammonia slip is consistently remaining below 5 ppm @ 15 percent O_2 averaged over 24 hours and that the initial exceedance was a false trigger.

Protocol: Compliance with ammonia slip limits shall be demonstrated by using the following calculation procedure:

ammonia slip ppmv @ 15% O_2 = ((a - (b x c/1,000,000)) x 1,000,000 / b) x d, where

a = ammonia injection rate (lb/hr) /17 (lb/lb-mol),

b = dry exhaust gas flow rate (lb/hr) /29 (lb/lb-mol),

c = change in measured NOx concentration ppmv at 15% O_2 across catalyst, and

d = correction factor.

The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip.

Verification: The project owner shall include ammonia slip concentrations averaged on an hourly and 24-hour basis calculated via the protocol provided as part of the Quarterly Operational Reports (**AQ-SC7**). The project owner shall notify

the CPM within 10 days of an exceedance of the 5-ppm ammonia slip limit herein. The project owner shall notify the CPM no less than 30 days prior to the scheduled date of the SCR ammonia injection grid replacement, repair, or reconditioning event. If the project owner finds that the exceedance of the 5-ppm ammonia slip limit was a "false trigger" as provided for in this condition, the project owner shall submit all relevant information to the CPM no less than 30 days prior to the scheduled date of the SCR ammonia injection grid replacement, repair or reconditioning event in order to cancel the event.

AQ-SC11 If the project owner does not participate in the voluntary California Climate Action Registry, then the project owner shall report to the CPM the quantity of CO_2 emitted on an annual basis as a direct result of facility electricity production.

Verification: Any CO_2 emissions that are reported to the California Climate action Registry or pursuant to this condition shall be reported to the CPM as part of the fourth Quarterly Operational Reports (**AQ-SC7**).

DISTRICT DETERMINATION OF COMPLIANCE CONDITIONS

Turbine Power Train Conditions

[Two (2) individual 1776 MMBtu/hr F Class Gas Turbine Generators]

[MDAQMD Permit Numbers: B008877 and B008878]

[Conditions AQ-1 through AQ-28 apply to each combustion turbine, unless otherwise specified.]

AQ-1 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each combustion turbine, manufacturer and design data. A summary of significant operation and maintenance events for each combustion turbine shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-2 This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf on a rolling twelve month average basis, and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: The project owner shall provide in the Quarterly Operational Reports (**AQ-SC7**) either a monthly laboratory analysis showing the fuel sulfur content, a monthly fuel sulfur content report from the fuel supplier(s), or the results from a custom fuel monitoring schedule approved by U.S. EPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG.

AQ-3 This equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and GG (Standards of Performance for Stationary Gas Turbines). This equipment is also subject to the Prevention of Significant Deterioration (40 CFR 51.166) and Federal Acid Rain (Title IV) programs. Compliance with all applicable provisions of these regulations is required.

Verification: At least ninety (90) days prior to the first firing of fuel in either turbine, the project owner shall provide the District, CARB and CPM with copies of the federal PSD and Acid Rain permits.

AQ-4 Emissions from this equipment (including its associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NOx and VOC during periods of startup, shutdown and malfunction:

a. Hourly rate, computed every 15 minutes, verified by CEMS and annual compliance tests:

   i. NOx as NO2 – 14.82 lb/hr (based on 2.0 ppmvd corrected to 15% oxygen and averaged over three hours)

   ii. CO – 18.04 lb/hr (based on 4.0 ppmvd corrected to 15% oxygen and averaged over 24 hours)

b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:

   i. VOC as CH4 – 2.90 lb/hr (based on 1 ppmvd corrected to 15% oxygen)

   ii. SOx as SO2 – 2.66 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)

   iii. PM10 – 6.0 lb/hr

Verification: The project owner shall submit the following in the Quarterly Operational Reports (**AQ-SC7**): All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol; a list of maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); and a log of all excess emissions, including the information regarding malfunctions/breakdowns required by District Rule 430. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip. Any maintenance to any air pollutant control system (recorded on an as-performed basis). Any permanent changes made in the plant process or production that could affect air pollutant emissions, and when the changes were made.

AQ-5 Emissions of CO and NOx from this equipment shall only exceed the limits contained in Condition **AQ-4** during startup and shutdown periods as follows:

a. Startup is defined as the period beginning with ignition and lasting until **either** the equipment **complies with all** ~~has reached~~ operating permit limits **specified in Condition AQ-4a for two consecutive 15-minute averaging periods or four hours after ignition, whichever occurs first.** Shutdown is defined as the period beginning with the lowering of equipment from base load and lasting until fuel flow is completely off and combustion has ceased.

b. **The emissions from each startup or shutdown event** ~~During a startup emissions~~ shall not exceed the following, verified by CEMS:

i. NOx – 376 lb

ii. CO – ~~3700~~ **3600** lb

Verification: The project owner shall include a detailed record of each startup and shutdown event in the Quarterly Operational Reports (**AQ-SC7**). Each record shall include, but not be limited to, duration, fuel consumption, total emissions of NOx and CO, and the date and time of the beginning and end of each startup and shutdown event. Additionally, the project owner shall report the total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, hours in shutdown, and average plant operation schedule (hours per day, days per week, weeks per year).

AQ-6 Emissions from this **facility, including the duct burners and cooling towers**, ~~equipment, including the duct burner,~~ shall not exceed the following emission limits, based on a calendar day summary:

a. NOx – 2924 lb/day, verified by CEMS

b. CO – 17,016 lb/day, verified by CEMS

c. VOC as CH4 – 187 lb/day, verified by compliance tests and hours of operation in mode

d. SOx as SO2 – 128 lb/day, verified by fuel sulfur content and fuel use data

e. PM10 – 336 lb/day, verified by compliance tests and hours of operation

Verification: The project owner shall submit in the Quarterly Operational Reports (**AQ-SC7**) the information required by **AQ-4** and a calendar day summary of emissions demonstrating compliance with these limits.

AQ-7 Emissions from this facility, including the duct burners and cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. NOx – 202 tons/year, verified by CEMS

b. CO – 685 tons/year, verified by CEMS

c. VOC as CH4 – 25 tons/year, verified by compliance tests and hours of operation in mode

d. SOx as SO2 – 23 tons/year, verified by fuel sulfur content and fuel use data

e. PM10 – 61 tons/year, verified by compliance tests and hours of operation

Verification: The project owner shall submit in the Quarterly Operational Reports (**AQ-SC7**) the information required by **AQ-4** and a rolling 12 month summary of emissions demonstrating compliance with these limits.

AQ-8 Particulate emissions from this equipment shall not exceed an opacity equal to or greater than twenty percent (20%) for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and Commission upon request.

AQ-9 This equipment shall exhaust through a stack at a minimum height of 130 feet.

Verification: Prior to the first firing of natural gas in either turbine the project owner shall provide to the District and the CPM as-built drawings of the stack or other suitable proof of the minimum stack height.

AQ-10 The project owner shall not operate this equipment after the initial commissioning period without the selective catalytic NOx reduction system with valid District permit # C008881 or C008882 installed and fully functional.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-11 The project owner shall provide stack sampling ports and platforms necessary to perform source tests required to verify compliance with District rules, regulations and permit conditions. The location of these ports and platforms shall be subject to District approval.

Verification: Prior to the first firing of natural gas in either turbine the project owner shall provide to the District and the CPM as-built drawings of the stack or other suitable documentation of the correct and complete installation of all necessary sampling ports and access platforms.

AQ-12 Emissions of NOx, CO, oxygen and ammonia slip shall be monitored using a Continuous Emissions Monitoring System (CEMS). Turbine fuel consumption shall be monitored using a continuous monitoring system. Stack gas flow rate shall be monitored using either a Continuous Emission Rate Monitoring System (CERMS) meeting the requirements of 40 CFR 75 Appendix A or a stack flow rate calculation method. The project owner shall install, calibrate, maintain, and operate these monitoring systems according to a District-approved monitoring plan and MDAQMD Rule 218, and they shall be installed prior to initial equipment startup.

Verification: Six (6) months prior to monitoring system installation, the project owner shall submit a monitoring plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the CEMS, continuous fuel monitoring system, and CERMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.

AQ-13 The project owner shall conduct all required compliance/certification tests in accordance with a District-approved test plan.

Verification: Thirty (30) days prior to the compliance/certification tests the project owner shall provide a written test plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the

test plan within 15 days of its receipt. Written notice of the compliance/certification test shall be provided to the District and CPM ten (10) days prior to the tests so that an observer may be present. A written report with the results of such compliance/certification tests shall be submitted to the District and CPM within forty-five (45) days after testing.

AQ-14 The project owner shall perform the following annual compliance tests in accordance with the MDAQMD Compliance Test Procedural Manual. The following compliance tests are required:

a. NOx as NO2 in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).

b. VOC as CH4 in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Methods 25A and 18).

c. SOx as SO2 in ppmvd at 15% oxygen and lb/hr.

d. CO in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Method 10).

e. PM10 in mg/m3 at 15% oxygen and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).

f. Flue gas flow rate in DSCFM.

g. Opacity (measured per USEPA reference Method 9).

h. Ammonia slip in ppmvd at 15% oxygen.

Verification: The annual source test report shall be submitted to the District and CPM no later than six (6) weeks prior to the expiration date of the District permit.

AQ-15 The project owner shall, at least as often as once every five years (commencing with the initial compliance test), include the following supplemental source tests in the annual compliance testing:

a. Characterization of cold startup VOC emissions;

b. Characterization of warm startup VOC emissions;

c. Characterization of hot startup VOC emissions; and

d. Characterization of shutdown VOC emissions.

Verification: Each annual source test report (**AQ-14**) shall either include the results of these tests for the current year or document the date and results of the last such tests.

AQ-16 Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B:

a. For NOx, Performance Specification 2.

b. For oxygen, Performance Specification 3.

c. For CO, Performance Specification 4.

d. For stack gas flow rate, Performance Specification 6 (if CERMS is installed).

e. For ammonia, a District approved procedure that is to be submitted by the project owner.

f. For stack gas flow rate (without CERMS), a District approved procedure that is to be submitted by the project owner.

Verification: The project owner shall provide the CPM documentation of the District's approval of the continuous monitoring systems, within 15 days of its receipt. The project owner shall make the site available for inspection of the continuous monitoring systems by representatives of the District, CARB and the Commission.

AQ-17 The project owner shall submit to the APCO and USEPA Region IX the following information for the preceding calendar quarter by January 30, April 30, July 30 and October 30 of each year this permit is in effect. Each January 30 submittal shall include a summary of the reported information for the previous year. This information shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request:

a. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx 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 NOx, CO, PM10, VOC and SOx (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 USEPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG)

h. A log of all excess emissions, including the information regarding malfunctions/breakdowns required by Rule 430.

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).

Verification: The project owner shall provide this information to the District and CPM in the Quarterly Operational Reports (**AQ-SC7**).

AQ-18 The project owner must surrender to the District sufficient valid Emission Reduction Credits for this equipment before the start of construction of any part of the project for which this equipment is intended to be used. In accordance with Regulation XIII the operator shall obtain 202 tons of NOx, 49 tons of VOC, 47 tons of SOx, and 61 tons of PM10 offsets (NOx ERCs may be substituted for VOC ERCs at a rate of 1.0:1, and PM10 ERCs may be substituted for SOx ERCs at a rate of 1.0:1).

Verification: The project owner must submit all ERC documentation to the District and the CPM prior to the start of construction.

AQ-19 During an initial commissioning period of no more than 120 days, commencing with the first firing of fuel in this equipment, NOx, CO, VOC and ammonia concentration limits shall not apply. The project owner shall minimize emission of NOx, CO, VOC and ammonia to the maximum extent possible during the initial commissioning period.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-20 The project owner shall tune each CTG and HRSG to minimize emissions of criteria pollutants at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-21 The project owner shall install, adjust and operate each SCR system to minimize emissions of NOx from the CTG and HRSG at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor. The NOx and ammonia concentration limits shall apply coincident with the steady state operation of the SCR systems.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-22 The project owner shall submit a commissioning plan to the District and the Energy Commission at least four weeks prior to the first firing of fuel in this equipment. The commissioning plan shall describe the procedures to be followed during the commissioning of the CTGs, HRSGs and steam turbine. The commissioning 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 timing of the dry low NOx combustors, the installation and testing of the CEMS, and any activities requiring the firing of the CTGs and HRSGs without abatement by an SCR system.

Verification: At least four (4) weeks prior to the first firing of natural gas in either turbine, the project owner shall submit a detailed Initial Commissioning Plan to the District and the CPM. This plan should provide detailed technical information regarding initial commissioning in a format that facilitates technical verification.

AQ-23 The total number of firing hours of each CTG and HRSG without abatement of NOx by the SCR shall not exceed 350 hours during the initial commissioning period. Such operation without NOx abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place and operating. Upon completion of these activities, the project owner shall provide written notice to the District and Energy Commission and the unused balance of the unabated firing hours shall expire.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-24 During a period that includes a portion of the initial commissioning period, emissions from this facility shall not exceed the following CO emission limits (verified by CEMS): 421 tons/year (rolling 12 month summary), 44,000 pounds/calendar day and 3700 pounds/hour.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report. In addition, after the end of the initial commissioning period the project owner shall continue to report the above data in the Quarterly Operational Report (**AQ-SC7**) for as long as monitoring period includes a portion of the initial commissioning period.

AQ-25 During a period that includes a portion of the initial commissioning period, prior to the steady state operation of the SCR system, emissions from this facility shall not exceed the following NOx emission limits (verified by CEMS): 273 tons/year (rolling 12 month summary), 22,000 pounds/calendar day and 1000 pounds/hour.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report. In addition, after the end of the initial commissioning period the project owner shall continue to report the above data in the Quarterly Operational

Report (**AQ-SC7**) for as long as monitoring period includes a portion of the initial commissioning period.

AQ-26 Within 60 days after achieving the maximum firing rate at which the facility will be operated, but not later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation at 100% load in compliance with the emission limits in Condition **AQ-4**.

Verification: Thirty (30) days prior to the initial compliance test, the project owner shall provide a written test plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the test plan within 15 days of its receipt. Written notice of the initial compliance test shall be provided to the District and CPM ten (10) days prior to the tests so that an observer may be present. A written report with the results of such initial compliance tests shall be submitted to the District and CPM within forty-five (45) days after testing.

AQ-27 The initial compliance test shall include tests for the following. The results of the initial compliance test shall be used to prepare a supplemental health risk analysis:

a. Formaldehyde;

b. Certification of CEMS and CERMS (or stack gas flow calculation method) at 100% load, startup modes and shutdown mode;

c. Characterization of cold startup VOC emissions;

d. Characterization of warm startup VOC emissions;

e. Characterization of hot startup VOC emissions; and

f. Characterization of shutdown VOC emissions.

Verification: The results of the initial compliance test (see **AQ-26**) and a supplemental health risk analysis shall be submitted to the District and the CPM within forty-five (45) days after testing.

AQ-28 The project owner shall provide sufficient space and appurtenances within the Heat Recovery Steam Generator to allow the subsequent installation of a high temperature oxidation catalyst.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each HRSG, manufacturer and design data showing this feature. If any VOC or CO limit specified by the above conditions is violated, within six (6) weeks the project owner shall submit a plan to install an oxidation catalyst. The catalyst shall be installed and operational within six (6) months of the violation.

Duct Burner Conditions

[Two (2) individual 132 MMBtu/hr Natural Gas Duct Burners]

[MDAQMD Permit Numbers: B008879 and B008880]

AQ-29 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each duct burner system, manufacturer and design data. A summary of significant operation and maintenance events for each duct burner system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-30 This equipment shall be exclusively fueled with natural gas and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, and Commission. A summary of significant operation and maintenance events for each duct burner system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-31 The duct burner shall not be operated unless the combustion turbine generator with valid District permit # B08877 or B08878 and selective catalytic NOx reduction system with valid District permit # C008881 or C008882 are in operation.

Verification: A summary of fuel use and equipment operation for each duct burner shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-32 Fuel use by this equipment shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

Verification: The above information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District or Commission personnel upon request.

Selective Catalytic NOx Reduction System Conditions

[Two (2) individual SCR systems]

[MDAQMD Permit Numbers: C008881 and C008882]

AQ-33 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each selective catalytic reduction system, manufacturer and design data. A summary of significant operation and maintenance events for each selective catalytic reduction system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-34 This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: A summary of significant operation and maintenance events for each selective catalytic reduction system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-35 This equipment shall be operated concurrently with the combustion turbine generator with valid MDAQMD permit # B008877 or B008878.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and Commission upon request.

AQ-36 Ammonia shall be injected whenever the selective catalytic reduction system has reached or exceeded 550° Fahrenheit except for periods of equipment malfunction. Except during periods of startup and shutdown, ammonia slip shall not exceed 10 ppmvd (corrected to 15% oxygen), averaged over **one hour** ~~three hours~~.

Verification: The project owner shall maintain a log of the SCR temperatures and the commencement of ammonia injection times. This information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and Commission personnel upon request.

AQ-37 Ammonia injection by this equipment in pounds per hour shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to MDAQMD personnel on request.

Verification: The above information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and Commission personnel upon request.

Cooling Tower Conditions

[One Cooling Tower]

[MDAQMD Permit Number: B008884]

AQ-38 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each cooling tower, manufacturer and design data. A

summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-39 This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-40 The drift rate shall not exceed 0.0006 percent with a maximum circulation rate of 146,000 gallons per minute (gpm), and the maximum Total Dissolved Solids shall not exceed 8190 ppm. The maximum hourly PM10 emission rate from this device and the evaporative condenser shall not exceed 2.00 pounds per hour, as calculated per the written District-approved protocol.

Verification: Compliance documentation in accordance with the written District approved protocol shall be submitted to the District and the CPM.

AQ-41 The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log which contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

Verification: A summary of the results of the weekly blow-down water quality tests and the results of the mass emission rate calculations shall be submitted in the Quarterly Operational Reports (**AQ-SC7**).

AQ-42 The operator shall conduct all required cooling tower water quality tests in accordance with a District-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District review and approval.

Verification: Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District and CPM review.

AQ-43 A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and available to District personnel on request.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.

[One Evaporative Condenser (Inlet Chiller)]

[MDAQMD Permit Number: B008883]

AQ-44 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each cooling tower, manufacturer and design data. A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-45 This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-46 The drift rate shall not exceed 0.0006 percent with a maximum circulation rate of 17,000 gallons per minute (gpm), and the maximum Total Dissolved Solids shall not exceed 8190 ppm. The maximum hourly PM10 emission rate from this device and the cooling tower shall not exceed 2.00 pounds per hour, as calculated per the written District-approved protocol.

Verification: Compliance documentation in accordance with the written District approved protocol shall be submitted to the District and the CPM.

AQ-47 The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log which contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

Verification: A summary of the results of the weekly blow-down water quality tests and the results of the mass emission rate calculations shall be submitted in the Quarterly Operational Reports (**AQ-SC7**).

AQ-48 The operator shall conduct all required cooling tower water quality tests in accordance with a District-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District review and approval.

Verification: Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District and CPM review.

AQ-49 A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and available to District personnel on request.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.

Emergency Fire Pump Conditions

[One emergency IC engine driving a fire pump]

AQ-50 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of the fire pump engine, manufacturer and design data. A summary of significant operation and maintenance events for the fire pump engine shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-51 This equipment shall be installed, operated and maintained in strict accord with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants.

Verification: A summary of significant operation and maintenance events for the fire pump engine shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-52 This unit shall be limited to use for emergency fire fighting, and as part of a testing program that does not exceed 60 minutes of testing operation per week (up to two hours once per year for annual testing and up to four hours once every three years for triennial testing).

Verification: The project owner shall make the fire pump engine operating records available for inspection by representatives of the District, CARB and the Commission upon request. The information shall be maintained on-site for a minimum of five years and shall be provided to District and/or Commission personnel on request.

AQ-53 The project owner shall use only diesel fuel whose sulfur concentration is less than or equal to 0.05% on a weight per weight basis in this unit.

Verification: The project owner shall make fuel purchase, MSDS or other fuel supplier records containing diesel fuel sulfur content available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-54 The project owner shall maintain a log for this unit, which, at a minimum, contains the information specified below. This log shall be maintained current and on-site for a minimum of five (5) years and shall be provided to District personnel on request:

a. Date of each test;

b. Duration of each test in minutes;

c. Annual operation summary, in calendar year fuel consumption (gallons) or hours; and,

d. Fuel sulfur concentration (the project owner may use the supplier's certification of sulfur content if it is maintained as part of this log).

Verification: The project owner shall make the fire pump engine operating records available for inspection by representatives of the District, CARB and the Commission upon request.

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BIOLOGICAL RESOURCES

Testimony of Natasha Nelson

INTRODUCTION

This section provides the California Energy Commission (Energy Commission) staff's analysis of potential impacts to biological resources from Caithness Blythe II, LLC's (applicant's) proposal for the construction and operation of the Blythe Energy Project II (BEP II). This analysis is primarily directed toward impacts to state and federally listed species, species of special concern, riparian vegetation, and other areas of critical biological concern. This document presents information regarding the affected biotic community, the potential environmental impacts associated with the construction and operation of the proposed project, and where necessary, specifies mitigation and compensation measures to reduce potential impacts to non-significant levels. This document also determines compliance with applicable laws, ordinances, regulations and standards (LORS), and specifies conditions of certification.

This analysis is based, in part, on information provided in the Applicant's Application For Certification (AFC) as revised on July 3, 2002 (BEP II 2002a, BEP II 2002d), Applicant's responses to Data Requests submitted on September 30, 2002 and March 14, 2003 (BEP II 2002g, BEP II 2003b); a site visit and discussion with Western Area Power Administration (Western), California Department of Fish and Game (CDFG) and U.S. Fish and Wildlife Service (USFWS); correspondence between the applicant and USFWS (BEP II 2004s), and correspondence between Western and the USFWS (Holt 2002, O'Rourke 2005). This site has been the subject of an amendment to an Energy Commission license given to the adjacent 520-MW power plant, Blythe Energy Project Phase I (BEP I) (CEC 2002). Information from BEP I compliance documents was also used in preparing this analysis. Relevant biological data collected during construction or operation of the BEP I was used by staff in preparing this analysis (Allen 2004, Allen 2005, Karl 2004a, Karl 2004b).

LAWS, ORDINANCES, REGULATION AND STANDARDS

The applicant will need to abide by the following laws, ordinances, regulations, and standards (LORS) during project construction and operation.

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., designates and provides for protection of threatened and endangered plant and animal species, and their critical habitat.

Migratory Bird Treaty Act

Title 16, United States Code, sections 703-712, prohibits take (i.e., harass, hunt, kill) or any attempts to take migratory birds.

Executive Order 13186 and Director's Order No. 172

Orders federal agencies to promote the conservation of migratory birds in all their actions through a Memorandum of Agreement and creation of a new Council for the Conservation of Migratory Birds. Under USFWS Director's Order No. 172, issued in June 2004, the USFWS is responsible for "Prevent[ion] or abate[ment of] the pollution or detrimental alteration of the environment for the benefit of migratory birds within the scope of our statutory authorities."

STATE

California Endangered Species Act of 1984

Fish and Game Code sections 2050 et seq. protects California's rare, threatened, and endangered species.

Nest or Eggs-Take, Possess, or Destroy

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

Birds of Prey or Eggs-Take, Possess, or Destroy

Fish and Game Code section 3503.5 protects California's birds of prey and their eggs by making it unlawful to take, possess, or destroy any birds of prey or to take, possess, or destroy the nest or eggs of any such bird.

Migratory Birds-Take or Possession

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

Fully Protected Species

Fish and Game Code sections 3511, 4700, 5050, 5515 prohibit take of animals that are classified as Fully Protected in California.

Significant Natural Areas

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

Native Plant Protection Act of 1977

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

California Code of Regulations

Title 14, sections 670.2 and 670.5 list animals of California designated as threatened or endangered.

LOCAL

Riverside County, California General Plan; Environmental Hazards and Resources

Goal 6 is to recognize and protect rare, threatened and endangered species of wildlife and vegetation as important County resources and a source of natural diversity.
Goal 8 is to recognize and promote the conservation of unique species of wildlife and vegetation found within a locale as an important County resource.

Riverside County, Airport Land Use Plan

The Comprehensive Land Use Plan for Blythe Airport, Riverside County, California (CLUP) was adopted by the Riverside County Airport Land Use Commission (ALUC) in August 1992. The CLUP is intended to protect and promote the safety and welfare of residents in the airport vicinity and users of the airport while ensuring continued operation of the airport. Five safety zones are defined around airports to promote the safety of persons on the ground while reducing risks of serious harm to crews and passengers of aircraft making forced landings in the immediate environs of the airport, and BEP II is within four of the five safety zones (see **LAND USE** section of this FSA). The CLUP states that any gathering of birds shall be prohibited within all safety zones. The County's General Plan allows for land use constraints (including restricting bird attractants in the flight zone) to protect surrounding residents.

City of Blythe, California General Plan

Biological Resources Goal 1 is to preserve and protect the City and regional biological resources, especially those of sensitive, rare, threatened, or endangered species of wildlife and their habitat and to encourage a balance between nature and human development.

Biological Resources Policy 1 states that the City will coordinate and cooperate with State and Federal agencies to preserve and enhance the recreational opportunities for fishermen and conserve habitat in the Colorado River.

Biological Resources Policy 2 states that the City will require or insist that responsible County, State and Federal agencies assure the provision of ample natural and enhanced open-space setbacks from the Colorado River's edge in conjunction with any development near or adjacent to the river's edge.

Biological Resources Policy 4 states that the Palo Verde Mesa habitat area extending from Interstate 10 to 20th Avenue and desert land immediately west will be designated as Open Space on the General Plan land use map to assure their protection as valuable and important wildlife habitat.

Biological Resources Policy 8 states that the City will encourage and/or if appropriate, require the use of native trees and vegetation, including palo verde, mesquite, cottonwood, ocotillo, and screwbean, in public areas, private common areas, street dividers, and other landscape areas where Planning Division control can be exercised.

Open Space and Conservation Goal 5 is the preservation of riparian and ruderal habitats as important breeding and foraging habitat for native and migratory birds and animals.

SETTING

REGIONAL

The proposed power plant is located in the Palo Verde Valley area of the Colorado Desert region, eastern Riverside County, just west of the Colorado River flood plain. The Palo Verde Valley was seasonally inundated by the Colorado River before several large dams were constructed upstream of Blythe. Since the installation of the dams and subsequent irrigation canals and drains, the Palo Verde Valley, and the surrounding terraces, have been transformed into a large agricultural area and service communities like Blythe have continued to grow. The remnant plant communities outside the agricultural and residential areas include: creosote bush (*Larra tridentata*) scrub, disturbed desert areas with ruderal vegetation, and riparian plant communities along the Colorado River and various canals and drains.

A variety of sensitive species are found in the project region. Sensitive species known to occur in the project region include desert tortoise (*Gopherus agassizii*), mountain plover (*Charadrius montanus*), southwestern willow flycatcher (*Empidonax traillii extimus*), Yuma clapper rail (*Rallus longirostris yumanensis*), and razorback sucker (*Xyrauchen texanus*). Desert tortoises are found primarily on flats with scattered shrubs and abundant herbaceous plants, with soils ranging from sand to sandy-gravel. Mountain plover forage from September to March within agricultural fields which have been recently cleared or burned, but do not nest in California. The remainder of the species are concentrated along the banks of the Colorado River which supports wetland and riparian communities. **BIOLOGICAL RESOURCES Table 1** includes the list of sensitive species that staff considered for this proposed project.

The BLM Desert Plan (BLM 1980), as amended, established three desert tortoise management Categories (I, II, III) for public land in the California desert. These categories supercede the original crucial habitat designations in the Desert Plan. The goals for the Categories are as follows:

- Category I habitat is to maintain stable, viable populations and to protect existing tortoise habitat values
- Category II is to maintain stable, viable populations and halt further declines in tortoise habitat values
- Category III is to limit tortoise habitat declines to the extent possible by mitigating impacts.

Although the project site does not fall within one of these Categories, there are Category I lands (designated as the Chuckwalla Desert Wildlife Management Area) approximately 6 miles west and Category III lands approximately 6 miles north.

BIOLOGICAL RESOURCES - TABLE 1

Sensitive Species
(BEP II 2002a, Tables 7.12-1 and 7.12-2)

Sensitive Plants	Status*
Harwood's milk-vetch (*Astragalus insularis var. harwoodii*)	CNPS List 2
Sensitive Wildlife	**Status***
California leaf-nosed bat (*Macrotus californicus*)	FSC/CSC
Cave myotis (*Myotis velifer*)	FSC/CSC
Occult little brown bat (*Myotis lucifugus occultus*)	FSC/CSC
Yuma myotis (*Myotis yumanensis*)	FSC/CSC
Greater western mastiff bat (*Eumops perotis californicus*)	FSC/CSC
Pale Townsend's big-eared bat (*Plecotus townsendii pallescens)*	FSC/CSC
Pallid bat (*Antrozous pallidus*)	CSC
Spotted bat (*Euderma maculatum*)	FSC/CSC
Brown pelican (*Pelecanus occidentalis*)	FE/CE
Western least bittern (*Ixobrychus exilis hesperis*)	FSC/CSC
White-faced ibis (*Plegadis chihi*)	FSC/CSC
Yuma clapper rail (*Rallus longirostris yumanensis*)	FE/CT
California black rail (*Laterallus jamaicensis coturniculus*)	FSC/CT/CFP
Western snowy plover (*Charadrius alexandrinus nivosus*)	FT/CSC
Mountain plover (*Charadrius montanus*)	CSC
Golden eagle (*Aquila chrysaetos*)	CSC/CFP
Bald eagle (*Haliaeetus leucocephalus*)	FPD/CE
Ferruginous hawk (*Buteo regalis*)	FSC/CSC
Merlin (*Falco columbarius*)	CSC
Prairie falcon (*Falco mexicanus*)	CSC
American peregrine falcon (*Falco peregrinus anatum*)	CE
Western yellow-billed cuckoo (*Coccyzus americanus occidentalis*)	CE
Short-eared owl (*Asio flammeus*)	CSC
Western burrowing owl (*Athene cunicularia hypugaea*)	FSC/CSC
California horned lark (*Eremophila alpestris actia*)	CSC
Gila woodpecker (*Melanerpes uropygialis*)	CE
Gilded northern flicker (*Colaptes chrysoides*)	CE
Vermilion flycatcher (nesting) (*Pyrocephalus rubinus*)	CSC
Southwestern willow flycatcher (*Empidonax traillii extimus*)	FE/ST
Loggerhead shrike (*Lanius ludovicianus*)	FSC/CSC
Crissal thrasher (*Toxostoma crissale*)	CSC
LeConte's thrasher (*Toxostoma lecontei*)	CSC
Bell's vireo (*Vireo bellii arizonae*)	FE/CE
Sonoran yellow warbler (*Dendroica petechia sonorana*)	CSC
Yellow-breasted chat (*Icteria virens*)	CSC
Northern cardinal (*Cardinalis cardinalis*)	CSC
Large-billed savannah sparrow (*Passerculus sandwichensis rostatus*)	FSC/CSC
Summer tanager (*Piranga rubra*)	CSC
Desert tortoise (*Gopherus agassizii*)	FT/ST
Flat-tailed horned lizard (*Phrynosoma macallii*)	CSC

* STATUS – FE = Federally listed Endangered; FT = Federally listed Threatened; FSC = Federal Species of Special Concern; FPE = Federal Proposed Endangered; FPD = Federal proposed (Delisting); California Native Plant Society (CNPS) List 2 = Plants rare, threatened or endangered in California but more common elsewhere; CE = California listed Endangered, CT = California listed Threatened; CSC = California Species of Special Concern; CP= California Proposed for Listing; CFP: California Fully-protected Species

LOCAL

East of the property are the Buck Boulevard substation and BEP I, a 520-MW power plant, which started turbine testing in summer 2003 and became commercially-operational in December 2003. Beyond the 520-MW power plant facility is a large citrus grove, which has been recently abandoned and trees removed, and the Western Area Power Administration's Blythe Substation. To the west is a sewage treatment facility and beyond that is the Blythe Airport which is a municipal facility providing regional air services with a daily average of 67 takeoffs or landings. Hobsonway runs along the southern border of the project, and just south of that is Interstate 10. Hobsonway serves as an Interstate 10 frontage road and a city business loop. This section of Interstate 10 connects Los Angeles to Phoenix and Tucson, and is highly traveled. Properties to the north contain fallow agricultural lands and abandoned citrus groves that have revegetated with locally abundant native and ruderal species.

The southern half of the adjacent BEP I power plant facility contains two 8-acre evaporation ponds which receive wastewater brine from the power plant's water treatment plant and cooling towers. The power plant has been discharging wastewater brine into the east evaporation pond since June 2003, but the west evaporation pond remains un-used. The west pond occasionally collects rainwater. The evaporation ponds have attracted flocks of wading birds, have been the site of several nests, and in general could be considered attractive to migratory and resident birds (Karl 2004a).

Power Plant Site

No sensitive species were identified on the site prior to the placement of fill. The site is surrounded by a permanent exclusionary fence (see Staff Analysis for the Blythe Amendment, CEC 2002). Although no sensitive species are expected within the fenceline so long as it is maintained as compacted fill and gates are kept closed, an occasionally sensitive species may gain access to the site. For instance, a single kit fox (*Vulpes macrotis*) was found trapped within the fence during a pre-construction survey on the site despite the fence being complete (Blythe Energy Project 2003). Birds can also access the site, but they are not expected to nest due to the lack of vegetation.

Prior to the placement of fill on the site starting in May 2003, the vegetation community for the proposed power plant site and construction laydown area was Sonoran creosote scrub, dominated by creosote and white bursage (*Ambrosia dumosa*) on sandy and gravelly soils. The site had some off-road tracks on it and some illegal dump sites were present. Sonoran creosote bush scrub is habitat for desert tortoise, a federal and state-listed species. Because the area had been categorized as potential desert tortoise and Harwood milk-vetch (*Astragalus insularis var. harwoodii*) habitat, the permanent land disturbance was mitigated for under the Blythe Amendment Biological Opinion (USFWS 2002a) and the Commission Order on the amendment (CEC 2002). No vegetation remains on site and the site is being maintained as compacted fill under an "Interim Weed and Erosion Control Program" (IWECP) which controls weeds with a polymer coating on the soil and occasional use of herbicides. The site will remain in this condition until August 2006, at which time the IWECP prescribes that natural vegetation be allowed to develop, so long as no industrial project is permitted on-site. This creates the possibility that the project may either be placed on either unvegetated compacted fill

or on natural vegetation depending on the timing of the Commission Decision. Wildlife would be expected on site, if the site is returned to natural vegetation.

The Cultural Resource Avoidance Area on the northern end of the parcel has been fenced in a manner that will allow passage of desert tortoises, or other wildlife to use the area. Under the Blythe Amendment (CEC 2002), the habitat loss of this area was mitigated because the applicant wanted to reserve the right to develop the area in the future without any additional permit review. The Cultural Resource Avoidance Area is covered with Sonoran creosote bush scrub. The applicant has stated that no construction will take place on the 10-acre site during construction and operation of the proposed power plant.

Traffic to and from the site is mostly along Hobsonway and Interstate 10. These roads cross through urban development, agriculture, and some disturbed native scrub habitat. A power plant worker living in Blythe would cross several canals to reach work, including Goodman drain. To enter the site, workers would go north on Buck Boulevard between BEP I and the abandoned citrus grove, and then travel west on Riverside Avenue. The driveway from Riverside Avenue has desert tortoise-proof fencing on both the west and east side and the gate has been built to be desert-tortoise proof. The area north of Riverside Avenue is undeveloped and is covered in Sonoran creosote bush scrub.

The City of Blythe upgraded Riverside Avenue to a 40-foot width within the 60-foot right-of-way. This work included drainage swales to divert the overland flows from the north to a drainage system at Buck Boulevard. The northwest corner of Riverside and Buck Avenues has some disturbance and soil compaction as it was used for waste storage during construction of the BEP I and the Buck Boulevard Substation (N. Nelson, personal observation).

Linear Facilities

The natural gas pipeline that would service BEP II was built during the construction of the adjacent BEP I power plant. Electrical lines would need to be installed across the BEP I parcel to link the BEP II power plant to the Buck Boulevard station. The adjacent 76-acre parcel is industrial and no wildlife habitat remains, with the exception of the bird use at the evaporation ponds. The Buck Boulevard switchyard was constructed on the BEP I parcel, is fully enclosed with a desert tortoise-proof fence, and contains no wildlife habitat.

IMPACTS AND ANALYSIS

STAFF'S CRITERIA FOR DETERMINING IMPACT SIGNIFICANCE

The California Environmental Quality Act (CEQA) Guidelines define direct impacts as those impacts that result from the project and occur at the same time and place. Construction and operation of the power plant are expected to have direct impacts to biological resources. Indirect impacts are caused by the project, but can occur later in time or farther removed in distance, but are still reasonably foreseeable and related to the project. As a result of the project, the applicant has proposed to place up to 786

acres of irrigated lands in rotational fallowing or permanent retirement and this action would be considered an indirect impact. The implications of this fallowing are also reviewed by staff for potential impacts. Projects that may occur at the same time or in the same place as the proposed project could cause cumulative impacts. The installation of numerous transmission lines, air pollution from the power plant, and the addition of an evaporation pond are evaluated for their potential cumulative impacts.

CEQA guidelines provide an environmental checklist to assist lead agencies in their analysis of project impacts. The headings for discussion of impacts presented in this section follow the items in that checklist, as well as items found in the Warren-Alquist Act and recent Presidential (executive) orders relevant to biological resources (e.g., Executive Order 13112 for management of invasive species). Significance is generally determined by compliance with applicable LORS; however, because of the diversity of biological impacts, guidelines adopted by resource agencies may also be used. These are appropriately cited in the text.

IMPACTS TO SENSITIVE SPECIES AND NATIVE PLANT COMMUNITIES

The power plant site is located on a highly disturbed, fenced parcel, adjacent to a power plant (which began operation in December 2003), intensive agriculture, a major interstate highway, and an airport. Although remnants of native plant and wildlife communities are in the regional area, the direct impacts from the construction of the project are quite limited. To ensure the remaining biological resources are protected the project owner has proposed to retain a Designated Biologist (Conditions of Certification **BIO-1** to **BIO-3**) and to have a worker education program (Condition of Certification **BIO-4**). All biological mitigation will be compiled into a comprehensive document known as a Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP, Condition of Certification **BIO-5**).

Power Plant Site, Cultural Resource Area and Laydown Area

Because construction would take place on the 66-acre section of the power plant site that has been previously fenced to exclude wildlife, construction of the project is not expected to impact wildlife. (Note: the 10-acre Cultural Resource Avoidance Area does allow wildlife access, but no construction is proposed in this area.) The loss of this open space took place when the area was fenced for the adjacent power plant's excess fill disposal. The loss has already been compensated for under the BEP I expansion amendment (USFWS 2002a; see Staff Analysis of the Blythe Energy Project Amendment, CEC 2002). However, the site will be managed to reduce potential harm and the fence will be monitored to ensure its integrity during construction (Conditions of Certification **BIO-6** to **BIO-8**).

Workers and delivery vehicles would access the site from Riverside Avenue. While Buck Boulevard and Hobsonway have urban uses along their shoulders, Riverside Avenue is open to potential desert tortoise habitat to the north and has very little local traffic. A peak working day will generate 640 to 690 project-related trips on these roads (BEP II 2002a, Table 7.4-6). While unpaved roads that carry only 25 cars per day show no impacts to desert tortoises, roads that carry average daily traffic of 220 to 800 vehicles can cause declines in desert tortoise sign (an indication of active use) out to

1.4 miles (2.25 km) from the road (Hoff and Marlow 2002). The high number of vehicles along Interstate 10 and Hobsonway has probably already depressed desert tortoise populations out to 2.6 miles (4.25 km), and increased construction traffic would not add to this existing impact. However, traffic-related desert tortoise fatalities as vehicles exit the site and continue along Riverside Avenue can be reduced with worker education program (Condition of Certification **BIO-4**) and appropriate speed limits (Condition of Certification **BIO-6**).

Burrowing owls are in the area, and were found during monitoring of the natural gas line installed for BEP I, but were not found on the BEP II project site in a 2004 survey (Karl 2004b). This species would move onto the site only if natural vegetation is restored prior to project construction. Nesting activity will be assessed by pre-construction surveys within 30 days of project construction and if they are found, then avoidance measures would be taken to reduce impacts to less than significant levels (Conditions of Certification **BIO-10**). The Fish and Game Commission received a petition to list the western burrowing owl as an endangered or threatened species on April 3, 2003 (Fish and Game Commission 2003). Since the release of the Preliminary Staff Assessment (PSA), a ruling on the petition was completed and the Fish and Game Commission has not recommended it for listing at this time. The 10-acre Cultural Resource Avoidance Area on the north edge of the parcel is currently fenced, but does not limit access to burrowing owls or other wildlife. Because the Cultural Resource Avoidance Area could become occupied with wildlife at any time, the project must survey for sensitive species prior to any disturbance of the area (see Conditions of Certification **BIO-10** and **BIO-11**) and workers should take precautions when entering the site (Condition of Certification **BIO-11**).

Construction at night would require local area lighting and increase noise at a time that is typically dark and quiet. It could also increase risk to species that are nocturnal, such as kit foxes, when they enter the active construction zone. Workers should be educated about the use of the site by wildlife in both daytime and nighttime scenarios (Condition of Certification **BIO-4**) and lighting shall be shielded to reduce its impact off-site (Condition of Certification **BIO-6**).

During operations, the cooling towers will emit mist and droplets of water into the atmosphere (known as cooling tower drift). Heavier droplets can fall onto soil and vegetation, and once evaporated, leave behind minerals and salts. Cooling water is cycled several times, and chemicals are added to reduce scaling of pipes and other equipment, thus, any droplet is likely to have salt and chemical components. The applicant estimates that the annual predicted deposition of cooling tower drift (in the form of PM10) would be 0.86 grams per square meter using conservative assumptions in the analysis (BEP II 2002a, page 7.12-8). Studies by Pawha and Shipley (1979) are often used as a threshold for significant impacts from cooling tower mist. The study exposed salt-sensitive vegetation (corn, tobacco, and soybeans) to saltwater mist and determined an annual rate of 2.98 grams per square meter was required to induce salt stress symptoms. Because the project's emissions are less than one-third of the threshold, the operation of the proposed cooling towers is not expected to cause harm to surrounding vegetation.

There are no impacts associated with the worker parking and staging area because it will be located on previously disturbed land that has been fenced to exclude desert tortoises. But construction traffic to and from this area is a concern (see discussion above).

Evaporation Pond

The BEP II project would have one evaporation pond, with two independent cells with a nominal surface area of 6.5 acres (BEP II 2004d). The cells are approximately 15 feet deep with 13 feet of water and solid storage (BEP II 2002g, Data Response 59). The pond would be lined with a black plastic liner and water would be allowed to evaporate unassisted. The primary wastewater streams to the evaporation pond would be from the water treatment plant and the cooling towers. The maximum flow rate of the treatment plant would be 18 gallons per minute and the average would be 13 gallons per minute (BEP II 2004d) which is equivalent to 18,720 to 25,920 gallons per day. Concentrated brine from the cooling tower is also directed to the evaporation pond at a rate of 14,400 to 25,900 gallons per day depending on ambient temperature (BEP II 2004d, Tables 2.0-1 and 2.0-2). The wastewater from the brine concentrator would have a sodium concentration of over 58,000 milligrams per liter (mg/L; BEP II 2002d, Table 7.13-7), which is nearly 1.5 times the salinity of ocean water. The wastewater would also have a high selenium concentration (1.8 mg/L; BEP II 2002a, Table 7.13-7). The site would direct surface runoff from rain events to the stormwater retention basin designed for the BEP I (BEP II 2002g, Data Response 69).

The evaporation pond is designed in much the same configuration as two existing ponds at BEP I, which are on the parcel of land directly east of the proposed power plant site. In addition, the proposed power plant would use the same groundwater source as BEP I and would use the same technologies to concentrate the water before discharge to an evaporation pond. Thus, throughout this section, the data collected from BEP I's evaporation ponds are used to illustrate the potential impacts from BEP II's evaporation pond.

The proposed evaporation pond is likely to attract birds and other wildlife (e.g. insects, bats, etc.). Bird monitoring at BEP I's evaporation ponds documented use by several resident birds for their entire life cycle and by migratory birds on a seasonal basis (Karl 2004a). There have been six black-necked stilt and four killdeer nests at the adjacent BEP I facility's evaporation ponds. In addition, on any given day biological monitors have observed 3 to 60 birds using the ponds to feed, drink, or roost. Invertebrates and algae are present at the ponds as well.

The water directed to the evaporation pond would contain some level of contaminants, including selenium and would be extremely saline. The direct loss of birds, bats, and/or other wildlife could result from ingesting these contaminants. Most birds are protected under the Migratory Bird Treaty Act as well as other state and federal laws. A more detailed analysis of this threat is presented below.

Water samples taken from BEP I's evaporation ponds indicate waterborne selenium levels in BEP II's evaporation pond will start around 0.10 mg/L to 0.20 mg/L (**Biological Resources Table 2**) based on a source water that contains selenium at 0.005 mg/L. Waterborne selenium alone is not a threat until very high levels of exposure. For

example, levels above 2.2 mg/L appear to impact mallard immune systems (Skorupa 1998). However, waterborne selenium quickly accumulates in the system as algae and then invertebrates consume higher and higher levels of the toxin (Lemly 1997). Invertebrates, if uncontrolled, can populate a pond and accumulate levels of selenium over 3 parts per million in just three years when selenium levels in water are only 0.01 mg/L (SEGS VIII and IX, Semi-Annual Water Quality Reporting submitted to the Energy Commission). An expert in wildlife contamination estimated that the selenium levels in the invertebrates at BEP I are around 63-100 parts per million (dry weight) based on the selenium levels found in the east evaporation pond's water (Steve Detwiler, during the February 15, 2005 Workshop).

BIOLOGICAL RESOURCES TABLE 2

Sample of Selenium Concentrations from the Blythe Energy Project Phase I (BEP I) Evaporation Pond and Wells in 2003 and 2004 (Allen 2005, Allen 2004a, Allen 2004b)

Type of Sample	Date of Sample	Sample Result
Water at Inlet to Evaporation Pond	June 2003	0.064 mg/L or 64 ug/L
Water at Inlet to Evaporation Pond	February 2004	0.12 mg/L or 120 ug/L
Water at Inlet to Evaporation Pond	June 2004	0.11 mg/L or 110 ug/L
Water at Inlet to Evaporation Pond	November 2004	0.37 mg/L or 370 ug/L
Water at Inlet to Evaporation Pond	December 2004	0.18 mg/L or 180 ug/L
Sludge Sample from Evaporation Pond	December 2004	Non-detect
Groundwater Sample from BEP Monitoring Well MW-1	June 2004	0.0054 mg/L or 5.4 ug/L

Selenium concentrations in water over 0.005 mg/L (or 5 ug/L) in combination with invertebrates with concentrations greater than 5 parts per million (dry weight) are considered hazardous to the health and long-term survival of wildlife populations (Lemly 1996). Based on the water testing results for selenium and the confirmed presence of algae, invertebrates, and birds at the existing ponds, staff expects that the proposed project as designed would be classified upon operation as "highly hazardous." This classification is defined as "an imminent, persistent toxic threat sufficient to cause complete reproductive failure in most species of fish and aquatic birds" (Lemly 1996).

Salt toxicosis in waterfowl has been reported in ponds with sodium concentration over 17,000 milligrams per liter (USFWS 1992, Windingstad et al. 1987). Birds spending a minimum of three hours at evaporation ponds with 52,000 to 66,000 mg/L sodium concentrations were considered to have toxic brain sodium concentrations (USFWS 1992). Salt toxicosis occurs when the bird can no longer excrete salt at levels equal to ingestion, and can be reversed if the birds can obtain fresh water. Salt toxicosis is more likely in birds that do not have previous exposure to saline waters, and thus have small supra-orbital salt glands, or birds that are under some form of stress (Wobeser and Howard 1987). There are no tests of sodium levels in the BEP I evaporation ponds, but high levels would be expected at BEP II's proposed pond because tests for sodium in the groundwater are high (Allen 2005) and the applicant estimated sodium would reach at least 52,000 mg/l (BEP II 2002a, Table 7.13-7). Another risk is that sodium can crystallize and encrust wildlife so that they can no longer fly when water temperatures

fall near freezing (Wobeser and Howard 1987). The probability of reaching temperatures low enough to cause encrustation are unlikely at the proposed facility because this is a desert environment.

Depending on the amount of wastewater discharged and the rate of evaporation, the concentration of selenium and sodium would increase over time, and the water will fluctuate between a minimum depth (0.1 to 2 feet) to the maximum of 13 feet in depth. At low levels of discharge and high levels of evaporation, we could expect that birds spending even less than three hours could ingest a lethal dose of sodium and can be exposed to levels of selenium that depress their immune systems. The level of water standing in the pond can determine how long individuals remain at the pond. For example, low levels of water at the existing ponds allowed for a sandy beach to develop, and this attracted several black-necked stilts to nest there in 2004 (Alice Karl, Workshop on February 15, 2005). In this case, birds were exposed for months to the selenium and sodium in the water. In addition, shallow waters allow algae and invertebrates to thrive, and thus the accumulation of contaminants such as selenium occurs at an even faster rate than in cooler deeper waters. In the ever changing electricity market, if at any point there are no baseload contracts for this project where continuous operation is ensured, then the amount of water in the ponds is expected to be shallow, and this creates the worse case scenario for sodium and selenium exposure.

Another concern regarding the evaporation pond is the potentially undesirable result of attracting wildlife to the power plant site which is within 5,000 feet of the Blythe airport runway. The Federal Aviation Administration (FAA) recommends new water treatment ponds that are potentially attractive to wildlife be kept at least 5,000 feet distant from the runway for protection of approach and departure airspace (FAA 1997). At the BEP I evaporation ponds, there have been flocks of shorebirds and egrets whenever water levels are low (Karl 2004a). The FAA classifies both shorebirds and egrets as “hazardous wildlife” (FAA 1997). Birds attracted to the adjacent evaporation ponds are likely to use the proposed pond for foraging activities or even for nesting. While the project’s evaporation pond in isolation could expect high bird use, the attractiveness of the adjacent ponds makes transient bird use even more likely. Furthermore, the California Department of Transportation Division of Aeronautics (CDOT) is specifically concerned that sand layers and riprap were eliminated from the design (CDOT 2004d) of the BEP II evaporation pond between April 2002 and April 2004 (see BEP II 2002d, Section 2.2.8.4, Figure 2.0-20 versus BEP II 2004d, Section 2.2.8.4, Figure 2.0-21). FAA’s policy is to recommend the installation of steep-sided, narrow, and riprap-lined basins when they must be located in proximity to airports (FAA 1997). Thus, the evaporation pond design is currently in violation of the prescriptions from the FAA. The potential for a cumulative impact from the addition of a new pond is discussed in a separate section below.

The PSA for BEP II included a section on the use of bird hazing as a possible technique to reduce impacts to migratory birds. Staff cited a bird-use study in Wyoming which showed bird hazing systems can reduce average mortality rates from 84 per year to 20 per year on 300 acres of wastewater ponds (BLM 2002). The applicant made several comments on the hazing section of the PSA (BEP II 2004e). The applicant argued that the use of hazing may cause noise impacts to surrounding areas, which staff agrees is

likely. The applicant also argued that other water sources are available for bird use and thus deterring birds is unlikely to be an issue (BEP II 2004e), however this is an invalid argument because the reverse has been proven true by biological monitoring of the adjacent ponds (Karl 2004a). In addition, the applicant used simple ratios to determine its pond would only kill 0.5 birds per year (BEPII 2004e, page 2) and must have assumed this small number would nullify staff's argument. However, intentional or unintentional mortality of even a single non-game migratory bird without a permit is a violation of the Migratory Bird Treaty Act and would be considered a significant impact. No permit for harm to non-game migratory birds can be issued to the proposed project under current law, so any mortality or harm is classified as a violation of the Act. Staff determined a workshop was needed to openly discuss the numerous options available to reduce impacts to migratory birds from contaminated evaporation ponds and to share information from the monitoring of the adjacent evaporation ponds.

Staff held a public workshop on February 15, 2005 to discuss the protection of birds from waterborne contamination. Attendees included various agencies, the applicant, and the owner of the adjacent BEP I power plant. The workshop discussion focused on how the selenium levels found in the water sampled for BEP I evaporation pond inlets compare to the agricultural system in Tulare Valley (which encompasses Kings, Tulare, and part of Fresno counties), and what techniques have been used to either reduce bird use at ponds or selenium from the water (CEC 2005n). Overall, the selenium levels at BEP I ponds exceed most natural systems, even those with high agricultural drainage such as the Tulare Valley.

Bird hazing systems may reduce bird use if implemented continuously and not in a haphazard manner. The use of visual hazing seemed to be more effective than the use of noise, but no technique was known to be completely effective. The use of chemicals to prevent foodchain accumulation has proven to be ineffective in evaporation ponds (see **BIOLOGICAL RESOURCES** Appendix A) and may result in other types of poisoning. No one attending the workshop encouraged foodchain interruption. The USFWS Contaminants Office in Sacramento was aware of a technique to remove selenium from waters before discharge (see **BIOLOGICAL RESOURCES** Appendix B), but the technique is still considered experimental and has not undergone scientific review. In addition, the technique is only able to remove 87 percent of selenium, so selenium levels at the BEP II evaporation ponds would remain around 13 to 48 ug/L, which is well above the 0.005 mg/L (or 5 ug/L) threshold.

The federal and state resource agencies responsible for wildlife protection and management, and water quality protection were contacted for follow-up by staff. We currently have four agencies responding to the proposed use of an evaporation pond for the disposal of wastewater.

- **U.S. Fish and Wildlife Service** (Sandy Marquez, personal communication to Natasha Nelson, February 23 and 24, 2005; CEC 2005n, CEC 2005o). USFWS, as a federal agency is obligated to protect migratory birds and said their first preference is to have the pond eliminated from the design or the selenium eliminated from the water so there was no risk of selenium contamination. If prevention is not feasible, then the applicant would need an intensive monitoring program and regular reporting to agencies. There should be adaptive management procedures adopted to ensure actions being taken to reduce avian exposure to selenium is effective.

- **California Department of Fish and Game** (CDFG 2005). CDFG is the Trustee Agency responsible for ensuring that fish and wildlife resources of the State are addressed properly under California Environmental Quality Act. They reviewed the monitoring from BEP I evaporation ponds and determined it is highly likely birds would utilize the pond proposed at BEP II, and that the birds would be exposed to water which would have adverse effects on their health. As a result, the pond could function as a mortality "sink," thus causing harm, and/or death to birds and other wildlife. Because of the likelihood that the ponds could cause harm, the CDFG supports the elimination of BEP II's proposed evaporation pond to avoid the take (e.g., harass, hunt, kill) of species that are protected by law.
- **Western Area Power Administration** (John Bridges, personal communication to Natasha Nelson, February 22, 2005; CEC 2005n). Western, as a federal agency, is obligated to protect migratory birds under Executive Order 13186. Western does haze birds from its substations and marks its transmission lines to prevent avian collisions. They have tested devices that seem to be working well. John Bridges thinks there would be technologies to haze birds effectively from the pond, but he is not aware of technologies that can reduce bird use to zero.
- **Regional Water Quality Control Board** (Michelle Ochs, personal communication with Natasha Nelson on February 18, 2005; CEC 2005n). The agency has published a draft Waste Discharge Permit for the use of an evaporation pond at the project, and public comments are being incorporated. Their regulatory oversight is limited and as such they do not consider biological impacts when issuing a permit. They want to ensure that any pond mitigation and monitoring program that is implemented: (1) protects the integrity of the pond liners (e.g., no drilling into the liner or risky sampling of solids) and (2) protects the wells from upset conditions (e.g., avoiding heavy equipment backing into well heads). In addition, the water levels must be kept low in order to maintain adequate protection from flooding. As part of the Waste Discharge Permit, they will require selenium testing of water in the quarterly reporting, and selenium in the solids when disposal is required. As a result of the February 15, 2005 Workshop, the permit will likely contain a discussion of selenium impacts to birds in the "Concerns and Mitigation" section.

Staff has evaluated available avian control methods and has determined them to be infeasible or ineffective at this location. After review of the agency comments, and careful consideration of the level of risk to migratory birds involved, staff's recommendation is for the project owner to redesign their approach to the project's wastewater stream. To avoid significant and unmitigated impacts, the applicant must find a permanent solution that ensures birds are not exposed to sodium in excess of 17,000 mg/L or selenium in excess of 0.005 mg/L (or 5 ug/L) concentration from the facility's wastewater stream. The reasons for staff's recommendation include:

- The proposed pond design is known to attract birds and as designed, birds are likely to attempt to feed, drink, roost, or nest in the pond.
- The installation of any bird attractants near airport runways is discouraged by the FAA, CDOT, and the Riverside County Airport Land Use Commission (ALUC).
- Operation of the power plant at less than full capacity (at any time during the lifetime of the power plant) is likely to create shallow waters which create algae blooms (and

hence higher rates of selenium accumulation) and shallow water is attractive to flocks of wading birds.

- Local birds and wildlife would not have toxic exposure to selenium but for the operation of the power plant's evaporation pond.
- Attempts to haze birds away from the evaporation pond are unlikely to have a high degree of success, and thus some exposure will be unpreventable. In addition, periodic hazing with noise could frighten birds up into the flight path of the airport runway and may cause noise impacts to the surrounding area.
- Attempts to eliminate invertebrates, and thus break the cycle of accumulation, are ineffective (**BIOLOGICAL RESOURCES** Appendix A) and will just trade the risk of exposure to other toxins. The open water in the pond would still remain attractive to migrating birds for stop-overs, which is against FAA, CDOT, and ALUC recommendations.
- Inexpensive methods to filter out selenium only remove around 90 percent of the selenium, so even after filtration, the selenium levels would remain a "high-risk" to migratory birds. In addition, this type of system, which uses its own open-air ponds, would be attractive to birds, and thus would still have the negative consequences for airport safety (**BIOLOGICAL RESOURCES**, Appendix B).
- Any lethal or sub-lethal effects that result in the death or decreased reproductive capacity of a migratory bird is a violation of the Migratory Bird Treaty Act as well as Fish and Game Code, Sections 3503, 3503.5 and 3505.

Staff recommends that the applicant choose one of the following two alternatives which could satisfy the bird hazard criteria:

1. Cease use of the evaporation ponds, install a zero-liquid-discharge-to-solids (ZLD) system, and truck all solids to an appropriate landfill. These systems can be installed on either a wet-cooling or dry-cooling power facility.
2. Filter contaminants (such as selenium) from the water. Successful systems include an Algal-Bacterial Selenium Removal Process system paired with a reverse osmosis system.

If one of these two project designs were to be chosen by the applicant, the design would need to undergo a complete analysis by staff for other technical issue areas for potential impacts and benefits. For example, the new project design would be evaluated by Traffic and Transportation staff for the likelihood of causing impacts to airport safety because of the proximity to the airport 's runway. Other impacts and benefits of a ZLD system are discussed in **SOIL AND WATER RESOURCES** Appendix A of this document.

The installation of a ZLD system which utilizes brine crystallization technology was proposed by staff in the PSA. The applicant has estimated that a brine crystallization system could be installed with wet-cooling towers in use, but that it would cost approximately $4 million for a non-redundant system (BEP II 2004e). The applicant was also concerned about annual maintenance costs. Staff has independently attempted to estimate the cost of these changes in another section of this document and these costs

are not repeated here because of their complex nature (see **SOIL AND WATER RESOURCES** Appendix A).

In general, much of the cost of the ZLD systems are offset by the net savings from the elimination of the evaporation pond. ZLD systems have been approved for use at many other facilities and are known to be efficient and effective. Use of ZLD system versus the use of an evaporation pond would create a water savings of 100 acre-feet per year. Reducing the use of fresh water by energy facilities is supported by the Energy Commission's 2003 Energy Report. For these reasons, staff prefers the use of a brine crystallizer or other ZLD system over filtration as a method to eliminate the significant impacts to birds from the proposed project. In addition, elimination of the pond is the only alternative that fully addresses airport safety concerns (see **BIOLOGICAL RESOURCES** Appendix B). An initial analysis of a ZLD system has been provided in other sections of this document (see **SOIL AND WATER RESOURCES, VISUAL RESOURCES, TRAFFIC AND TRANSPORTATION**) to enable the public to understand the implications of this design change, but a full analysis by all technical areas would still be needed prior to Commission approval of the project.

Linear Facilities

BEP II's electrical lines would connect to the Buck Boulevard Substation which is already constructed on the adjacent 76-acre parcel. However since the lines would cross an already industrialized site, staff does not expect any direct loss to sensitive species. Any small lines would be built following Avian Power Line Interaction Committee Guidelines (BEP II 2002a, Condition of Certification **BIO-6**) so the potential for electrocution of large perching birds is low. Avian collisions with the electrical lines are not expected due to the short length of the lines and the proximity to existing power plant infrastructure.

There are several regional transmission line projects being proposed by Imperial Irrigation District (IID), FPL Energy, and Southern California Edison from Blythe to other desert locations. These projects are under permit review at the same time as this application. Many of these projects connect to the transmission system near the proposed power plant site. The applicant has said BEP II is to be constructed in response to these transmission line projects being completed, not the reverse (BEP II 2004s). The USFWS will consider the regional lines to be a separate project so long as they are permitted separately and the Energy Commission limits BEP II's power delivery to less than full capacity until a regional transmission line project is separately permitted and constructed (O'Rourke 2005). This topic is discussed more under cumulative impacts. Staff has so far opposed any condition of certification that limits power output, so this restriction is less than certain (see **TRANSMISSION SYSTEM ENGINEERING** section of this document).

Critical Habitat and Recovery Plan Goals

The nearest critical habitat unit for the desert tortoise is the Chuckwalla Bench located approximately 10 miles to the west of the project site. This unit was established in 1994 as part of the USFWS management to protect this species. The same area is to be managed per the prescriptions of the 1994 Desert Tortoise (Mojave Population) Recovery Plan (USFWS 1994). Declines in the population at Chuckwalla Bench have

been severe, attributable to vandalism, vehicle kills, raven predation and shell disease (USFWS 1994). The proposed power plant would not increase the risk of any of these threats and would not have any physical effects on this area.

Southwestern willow flycatchers, a small migratory bird, have been found along the Colorado River. The lower Colorado River is one of six Recovery Units defined within the USFWS's Recovery Plan for this species. The USFWS goal for flycatcher populations in this segment of the Colorado River is to increase territories from the existing 3 to 150. The lower Colorado River is a managed river with three large dams (Hoover, Davis and Parker) and five small dams (Headgate Rock, Palo Verde, Imperial, Laguna and Morelos) that provide diversions for agricultural and municipal uses serving three states and the Republic of Mexico. Virtually all the riverine reaches remaining after the construction of the large and small dams were channelized or stabilized to some degree. These flood management structures have had an irreversible impact on the amount of riparian vegetation within the river. Many solutions for improving flycatcher habitat require increased availability of water in active channels or in near-channel areas.

The project's use of groundwater is connected to and will reduce water in the Colorado River (see **SOIL AND WATER RESOURCES**). However, even when considered in conjunction with the adjacent power plant's water use, pumping is unlikely to measurably decrease water availability in the Colorado River or in near-channel areas, and there is little possibility of impacts to southwestern willow flycatcher Recovery Plan goals. However, the Recovery Plan states: "All water users, whether municipal, agricultural, or industrial, need to work together and bear their share of water overdraft problems to achieve results" (USFWS 2002b, p. 110). Water Resources staff is proposing several ways to decrease the amount of groundwater used (see Appendix A to the **SOIL AND WATER RESOURCES** analysis). Staff's proposal to eliminate the evaporation pond, and convert the power plant to a ZLD system could reduce water use by over 100 acre-feet per year. Although the proposed project would not impact the Recovery Plan directly, all actions to reduce the use of groundwater (or fresh water) would be consistent with the USFWS's Recovery Plan goals.

Agricultural Fallowing or Permanent Retirement

The applicant intends to implement a Water Conservation Offset Program (WCOP) in exchange for project water use. The applicant proposes to retire irrigated lands permanently or fallow lands on a rotating basis to reduce demand for agricultural irrigation in the region (BEP II 2002a, p. 7.2-6). The WCOP would include the permanent retirement or rotational fallowing of lands within Palo Verde Irrigation District (PVID) boundaries on the Mesa or the Palo Verde Valley (BEP II 2002a, p. 7.13-3). Fields in rotational fallowing would be left as stubble or as clodded earth for up to five years, and orchards may be removed (BEP II 2002f, Data Response 8). The use of agricultural land by sensitive wildlife, whether active or fallow, is limited due to the highly developed nature of the Mesa and Palo Verde Valley plateau and high human presence. No special status species are identified as residing on agricultural lands exclusively, however wintering mountain plover are attracted to recently disturbed fields and sparse vegetation. Use of fallowed fields by the plover could increase with the lower level of human activity on the sites or decrease due to the loss of prey (grasshoppers). Overall, removing 786 acres of fields out of random and sporadic cycle

of disturbance (from fire or tilling) would be small in comparison to the number of fields still in the vicinity (estimated at 104,000 irrigated acres). In addition, the sparse vegetation on the fallowed fields could be as attractive to the plover as a recently burned field, if prey items were available. Staff does not expect impacts to special status species as a result of permanent retirement or fallowing of fields.

IMPACTS TO SURFACE WATERS

During storm events, runoff from the project site would be directed to a stormwater detention pond on the adjacent parcel. This water will be filtered of pollution (such as oil or waste) prior to disposal in the detention pond, and will be monitored for water quality (Condition of Certification **SOIL & WATER-3**). No significant biological resources impact is expected from the temporary storage of storm water in a detention basin.

Wastewater from BEP II operations would be stored in a lined evaporation pond on-site. No surface waters are expected to be contaminated as long as the Waste Discharge Permit conditions are followed (see **SOIL AND WATER RESOURCES**). The use of a ZLD system or filtration, as proposed by staff, are unlikely to have impacts to surface waters.

IMPACTS TO WILDLIFE MIGRATION CORRIDORS

The nearest potential wildlife migration corridor is the Colorado River which attracts a large number of species because of its abundant year-round water and diverse vegetation. Project construction and operation are of sufficient distance from the river that no impact is expected.

IMPACTS TO COMMERCIAL AND RECREATIONAL SPECIES

No commercial or recreational species were identified during surveys at the site or within 1 mile of the site. Project construction and operation will not cause an impact to these species.

IMPACTS FROM WEEDS

The permanent and temporary earth disturbance adjacent to native habitats increases the potential for exotic, invasive plant and animal species to establish and disperse into native plant communities, which leads to community and habitat degradation. Both the State and Federal governments have recognized and taken action on the threat that exotic species pose to native habitats and agriculture. As exotic plants replace native habitat, many species of birds, insects, fish and other wildlife may be lost. It has been estimated that invasive pest plants cost California hundreds of millions of dollars annually (CalEPPC 1999). California's Governor Davis signed and funded Assembly Bill 1168 - Noxious Weeds Management Program in 1999, indicating the State's commitment to manage noxious weeds. At the federal level, Executive Order 13112 was also signed in 1999, to "prevent the introduction of invasive species and provide for their control and to minimize the economic, ecological, and human health impacts that invasive species cause". Staff seeks to prevent indirect impacts to native plant communities on the north and west side of the power plant site and has identified weed control as part of the project owner's responsibility during construction and operation (see Condition of Certification **BIO-7**).

In addition, staff is recommending the continuation of the "Interim Weed and Erosion Control Prevention Program" on the project site during the interval between the Commission Decision and the time of construction. As proposed in the BEP Amendment, this successful Program is set to expire in August 2006, or at the time of a Commission Decision or other project permit. While staff allowed for the release of weed control responsibilities by BEP I owner, this does not release the new project owner from responsibilities, and indeed the burden of weed control is only passed at the time a permit is issued from the BEP I owner to the new owner of the project site. Because there have been multiple-year-long delays in construction for at least four Commission approved projects in California since 2001, including Inland Empire (01-AFC17), Tesla (01-AFC-21), East Altamont (01-AFC-04), and Salton Sea Unit 6 (02-AFC-02), staff is concerned that the weed bank that is on this particular site could grow unabated during the months or years between the Commission Decision and the commencement of construction. Staff recommends adoption of an "Interim Weed and Erosion Control Prevention Program", similar to the one that exists, by the BEP II project owner (see Condition of Certification **BIO-7**) to prevent harm to the natural communities to the north and northwest of the site.

CUMULATIVE IMPACTS

Cumulative impacts are those that result from the incremental impacts of an action added to other past, present, and reasonably foreseeable future actions, regardless of who is responsible for such actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

AIR POLLUTION EFFECTS

The operation of the proposed facility would generate air pollutants from the combustion of natural gas. In 1999, Riverside County had at least 145 point sources of nitrogen oxides, producing over 1,400 tons per year (tpy)(EPA 2005). During operations, the nitrogen oxide contribution of the plant to the air basin is 191 tpy (BEP II 2002a, Tables 7.7-1 and 7.7-12), so BEP II would cause a 13 percent increase over Riverside County's yearly total if left unmitigated. The maximum deposition from nitrogen oxides is calculated as 0.27 kilograms per hectare per year (kg/ha/yr) (BEP II 2003b, Data Response 121). In addition to the nitrogen deposition from combustion, the proposed facility has nitrogen deposition from its air emission control technology in the form of ammonia. During operations, BEP II proposes to have an ammonia slip rate of 10 parts per million (ppm) except during periods of start-up, shutdown, and malfunction (BEP II 2002d, AFC p. 7.7-28). The applicant is unwilling to reduce the ammonia slip rate to 5 ppm (BEP II 2004o). The Air District's 10 ppm requirement for ammonia slip is inconsistent with the comments from U.S. EPA, which "strongly recommend" a limit of 5 ppm for BEP II (U.S. EPA 2002a) and guidance from CARB (CARB 1999). These agencies indicate that the more stringent ammonia slip level is achievable, and Air Quality staff agrees (see **AIR QUALITY**). Biology staff supports Condition of Certification **AQ-SC-10** which limits the ammonia slip rate which overall is likely to reduce the nitrogen loading on local vegetation. Biology staff also supports the purchase of nitrogen-based emission reduction credits to improve regional air quality (Condition of Certification **AQ-SC-9**).

The nitrogen deposition rate considered sufficient to affect ecosystem structure and diversity is 3 to 10 kg/ha/yr depending on vegetation type (Fox et al. 1989). The closest monitoring station for nitrogen deposition is Joshua Tree National Park, about 55 miles to the west. In 2001, Joshua Tree National Park had an annual nitrogen oxide deposition rate of 1.03 kg/ha/yr, an ammonia deposition rate of 0.30 kg/ha-yr (NAD 2001), and a total nitrogen deposition rate of 3.3 kg/ha/yr (CASTNET 2001). Therefore, ambient conditions in this desert region are at a level of concern. BEP II emissions, if left unmitigated, would increase ambient levels at the site and immediate area by around 19 percent to 3.949 kg/ha/yr. At this time, there are no sensitive communities or plants within the plume of the power plant, and thus the impact of ammonia deposition is adverse but not significant.

During the commissioning phase, BEP II's air emission contribution is higher because pollution controls are not in place or are being calibrated. Modeling data estimated that during commissioning, the maximum contribution of nitrogen oxides is 4.3 kg/ha/yr (BEP II 2002g, Data Response 26; BEP II 2002a, Table 7.7-40). Thus, there is a potential doubling of nitrogen deposition in the local area during the commissioning phase. The impact of the deposition would be dependent on the precipitation amounts during the commissioning phase, but is most likely to cause some level of increased foliar development in surrounding vegetation. Staff does not have enough information on the local area to make conclusions on long-term nitrogen deposition effects in the Mojave and Colorado desert regions, but nitrogen deposition may be a causal factor in the invasions of Mediterranean grasses in coastal sage scrub (Fenn et al. 2003).

Joshua Tree National Park would not likely receive an increase in air pollutants because of its distance from the proposed BEP II project; most of the deposition from operations is on the northern fence line of the facility, with a plume of emission extending north and east of the site for approximately 2 miles before reaching a level that is below the modeling threshold (less than 0.05 µg/m3) (BEP II 2002a, Figure 7.7-10). The National Park Service does not believe that the proposed project will create an adverse impact on visibility or air quality related values at Joshua Tree National Park (Codding 2003). The applicant's proposal to reduce regional air quality impacts with the purchase of nitrogen-based emission reduction credits will likely improve air quality at the Park (see **AIR QUALITY,** Condition of Certification **AQ-SC-9**).

TRANSMISSION LINE UPGRADES IN THE MOJAVE DESERT

Since publication of the PSA in November 2003, BEP I's Transmission Amendment was filed with the Energy Commission, and the permitting for the Imperial Irrigation District's Desert Southwest Transmission Project and Southern California Edison's Palo-Verde to Devers II Project is still incomplete. These projects are on three separate permitting tracks, and the cumulative biological resources impacts from these projects are discussed below. Until a transmission line project is permitted, staff will not know how the electricity generated from BEP II will reach its markets. However, when the power plant decides which of the three lines under proposal it will connect to, there could be a need for downstream facilities that are the result of system impacts (e.g., upgrades in transmission lines to increase conductor capacity, or installation of facilities in existing substations). Staff has no way to evaluate these downstream impacts until the applicant provides a valid System Impact Study.

Imperial Irrigation District is in the process of reviewing a transmission line connection between Buck Boulevard Substation and Devers Substation (to the east). The line would be known as the Desert Southwest Transmission Project (DSWTP). The transmission line would cross desert tortoise habitat, with observed densities for the area ranging from 75 to greater than 100 adults per square mile (IID/BLM 2003, page 3.1-37). The DSWTP would have temporary and permanent impacts to desert tortoise lands (**BIOLOGICAL RESOURCES**, Table 3). The proposed survey effort and mitigation package for the transmission line should be adequate to identify and address the project impacts. The project is under Section 7 consultation with the USFWS for impacts to desert tortoise and other federally listed species. If BEP II were to connect to this transmission line, any downstream improvements are likely to impact desert tortoise and its habitat, and require changes to the Section 7 consultation.

BIOLOGICAL RESOURCES - TABLE 3

Habitat Loss (in acres) from Desert Southwest Transmission Line Proposed Project (IID/BLM 2003, Table 3.1-2)

Activity/ Project Component	Trans. Line Options	Sonoran Creosote Brush (Temp/ Perm)	Desert Dry Wash (Temp/ Perm)	Agricultural Land (Temp/ Perm)	Sonoran Desert Mixed Scrub (Temp/ Perm)	Mojave Creosote Brush Scrub (Temp/ Perm)
Substation/ Switching Station at Hobsonway	230-kV	None	25/25	None	None	None
	500 kV		25/25			
Devers Substation Modifications	230-kV	None	None	None	None	5/5
	500 kV					5/5
Dillion Road Substation	230-kV	None	None	None	None	25/25
	500 kV					25/25
Tower Footings	230-kV	427/12	243/7	13/1	195/5	192/5
	500 kV	366/10	209/6	11/1	167/5	164/5
Pulling and Tensioning Sites	230-kV	26/0	15/0	1/0	12/0	12/0
	500 kV	26/0	15/0	1/0	12/0	12/0
Spur Roads	230-kV	11/11	6/6	1/1	5/5	5/4
	500 kV	10/10	6/6	1/1	4/4	5/4
TOTAL	230-kV	**464/23**	**289/38**	**15/2**	**212/10**	**239/39**
	500 kV	**402/20**	**255/37**	**13/2**	**183/9**	**211/39**

Southern California Edison's (SCE) Palo-Verde to Devers II Project has been in planning for over 10 years. SCE has applied for a permit from the California Public Utilities Commission, which must determine that the project has a legitimate public need and would result in public good. The applicant stipulates that this project could eventually be "connected" to either the BEP I or BEP II power plant facilities (BEP II 2004s). If BEP II were to connect to this transmission line, any downstream improvements are likely to impact desert tortoise and its habitat, and require changes to the Section 7 consultation.

BEP I has amended its application to expand its connection at Buck Boulevard Substation and proposes two transmission line connections, through a project called the Blythe Energy Project Transmission Line (BEPTL). One connection is 7 miles, and a second is 67 miles in length. In addition, there is a proposal for a new substation called MidPoint which would impact 40 acres of desert tortoise habitat. Staff identified the transmission lines and substation could have impacts to desert tortoise, burrowing owl, Harwood's milk-vetch, Cove's cassia, crucifixion thorn, mesquite nest-straw, Orocopia sage, and Mojave fringe-toed lizard. Staff has proposed Conditions of Certification that would mitigate impacts to levels less than significant in its analysis.

If a connection to one of these transmission lines is eventually part of the BEP II project, and if upgrades were needed along this line, then staff would evaluate and recommend mitigation of those impacts in a similar manner. Crossing the desert within a previously undisturbed transmission line corridor would continue to degrade and fragment the desert. The proliferation of approved utility corridors, along with the attraction of transmission line roads for off-road enthusiasts, has resulted in negative impacts to desert tortoise communities (Hoff and Marlow 2002, Bury and Luckenbach 2002). These negative impacts are significant for their individual impact as well as collectively because fewer undisturbed desert locations remain as a result of a series of decisions to allow more utility corridors. The efforts of the Desert Tortoise Preserve Committee to purchase and protect lands from future development are an attempt to offset the impacts of utility corridors, but their efforts can never match the scale of the habitat loss which has gone unmitigated for many years. The cumulative loss of desert tortoise habitat could not be established definitively in this proceeding, but will be carefully evaluated if the project needs to upgrade facilities along one or more of these proposed transmission lines in the future.

INCREASING THE NUMBER OF OPEN-AIR PONDS AND RISKS TO AIRPORT SAFETY

At the time staff evaluated the installation of evaporation ponds at BEP I, little was known about bird use at ponds because there were no large water bodies on the Mesa, only small sumps and canals. For this application, staff referred to the monitoring results from the BEP I evaporation ponds (Karl 2004a) to evaluate whether the addition of another pond would cause compounding (cumulative) impacts to birds and airport safety.

Bird use at the adjacent BEP I power plant's 18 acres of evaporation ponds has been confirmed by operational monitoring (Karl 2004a). Flocks of birds occasionally congregate on the surface and some even nest on the shoreline of the ponds. Included in the species mix are several species that are classified as "hazardous wildlife" by the

FAA, including shorebirds and egrets (FAA 1997). Overall, the adjacent evaporation ponds would be classified as a bird attractant to hazardous wildlife when low water levels are present. While the project's evaporation pond in isolation would expect some bird use, the attractiveness of the adjacent ponds makes bird use even more likely.

Because birds are likely to use the proposed BEP II evaporation pond, which is closer to the flight approach for planes, staff determined the addition of more open-air ponds is likely to cause a significant cumulative impact to both birds and airport safety. The only mitigation that is likely to succeed in reducing this dual impact is the elimination of the evaporation pond from the design, thus staff recommends the project applicant pursue ZLD rather than the filtration of the water.

MITIGATION

APPLICANT'S PROPOSED MITIGATION

The applicant has proposed in the AFC several impact avoidance measures to reduce impacts to biological resources in the Blythe area (BEP II 2002a). The applicant will:

- Designate a project biologist to manage all biological resource conditions of certification;
- Develop and institute a Worker Environmental Awareness Program to inform construction and operations workers about biological resources associated with the project.

These measures have been incorporated into Conditions of Certification **BIO-1** through **BIO-4**. The project owner will submit these and other measures along within a comprehensive mitigation and monitoring document (Condition of Certification **BIO-5**).

During construction, the applicant will continue to implement measures to avoid harm to species such as monitoring open trenches, installing raptor friendly power lines, handling any desert tortoise encountered using the latest protocol, and controlling trash. These measures have been incorporated into Condition of Certification **BIO-6**. The applicant has agreed to monitor the fenceline to ensure integrity and to fix breaks quickly (Condition of Certification **BIO-8**). The applicant has committed to not disturbing the 10-acre cultural resource avoidance area (Condition of Certification **BIO-11**).

During operation, the applicant has agreed to evaluate the level of bird use at the proposed evaporation pond. The applicant has agreed that if the sodium and selenium levels reach a critical threshold, then they would be willing to start hazing birds from the ponds (BEP II 2004s). Such measures will allow for assessments of use of the area by wildlife and could highlight if any harm is occurring, but would be inadequate to protect species from harm initially.

STAFF'S PROPOSED MITIGATION

The use of the site by wildlife has been highly-controlled by the installation of a desert tortoise-proof fence along the edge of the project. However, staff determined there was still an opportunity for wildlife to enter the site, much like the kit fox did in March 2003.

Therefore, staff proposes a protocol for handling these incidents to ensure biological oversight (Condition of Certification **BIO-9**).

Staff is also proposing that the applicant regard the Cultural Resource Avoidance Area to the north of the power plant as potential wildlife habitat. This area has a gap between the ground level and the fence that allows wildlife access. Thus, any action taking place in the area, including weed control, should be limited and the proper care taken to protect wildlife (Condition of Certification **BIO-11**).

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

To be in compliance with applicable laws, ordinances, regulations and standards, BEP II must obtain two biology-related permits: (1) a USFWS determination on the potential for take of listed species, as undertaken by the federal-lead, Western; and (2) a CDFG Section 2080.1 Letter of Concurrence. To obtain a USFWS determination, the federal lead for the project, Western, submitted the Biological Assessment, and asked for concurrence with their determination of no effect to desert tortoise. The USFWS requested additional information, and then issued their concurrence of “no effect” on federally-listed species on January 20, 2005 (O’Rourke 2005). The CDFG Section 2080.1 Letter of Concurrence is dependent on the finalization of the federal documents and the finalization of this CEQA process. CDFG has been involved in meetings with Western and USFWS (October 10, 2002) and should be able to issue this permit within 30 days of the Commission issuing its decision.

The Migratory Bird Treaty Act (Act) and several state laws prohibit the harassment and killing of non-game migratory birds without a permit. The Act does not distinguish between an action that is intentional and one that is unintentional. Harassment or killing of even one non-game bird without a permit is a violation of the Act and is punishable by time in jail and fines. Individuals and companies cannot harm migratory birds except under very strict circumstances, such as scientific research, or with a game-hunting license, which has strict bag-limits and schedules.

Most of the bird species identified as using the evaporation ponds at the adjacent power plant are protected by the Act and other laws, are non-game species, and would be expected to use BEP II’s proposed evaporation pond. Some of the bird species are game species, but can only be taken with a hunting license during a specific season. The evaporation pond is likely to create a “high risk” environment for birds because water containing measurable levels of sodium and selenium is being brought to the surface and then, after being concentrated by the power plant operations, would be discharged into an open-air pond. This toxic water would be unavailable to wildlife but for the operation of the local power plants. Even when every attempt is made to discourage selenium uptake by birds, staff predicts a bird could be contaminated at either a lethal level (where offspring showed deformations) or a non-lethal level (where population growth was suppressed) during the lifetime of the project. Attempts to eliminate the uptake of excessive sodium are likely to also fail.

The project as proposed would likely violate the Migratory Bird Treaty Act and Fish and Game Codes 3503, 3503.5 and 3505. To prevent a violation of the laws protecting these birds, the CDFG, the USFWS and staff's recommendation is for the applicant to redesign the project's wastewater stream system.

FACILITY CLOSURE

Sometime in the future, the BEP II will experience either a planned closure, or be unexpectedly (either temporarily or permanently) closed. When facility closure occurs, it must be done in such a way as to protect the environment and public health and safety. To address facility closure, an "on-site contingency plan" will be developed by the project owner, and approved by the Energy Commission Compliance Project Manager (CPM). Facility Closure mitigation measures will also be included in the Biological Resources Mitigation Implementation and Monitoring Plan prepared by the applicant.

However, in the event that the Energy Commission CPM decides that the facility is permanently closed, the facility closure measures provided in the on-site contingency plan and Biological Resources Mitigation Implementation and Monitoring Plan would need to be implemented.

RESPONSE TO COMMENTS

Staff received one public comment on its analysis from Carmela F. Garnica, in an e-mail dated February 15, 2005.

Ms. Garnica has requested off-site mitigation for habitat loss based on selected issues identified in a March 12, 2001 letter from Dr. Shawn Smallwood. Dr. Smallwood's letter broadly addresses issues with a previous power plant project in Blythe (now known as BEP I) which was evaluated under a different proceeding. Dr. Smallwood's letter is not specific to the current proceeding. Staff wrote the Final Staff Assessment for BEP I, the testimony for the current proceeding (BEP II), and has continued involvement in the compliance proceedings from BEP I, thus staff has extensive knowledge of both projects. Staff's reply is limited to how the issues relate to the current project under Commission review (Docket 02-AFC-01). In addition, staff restricted comments to the major issues selected by Ms. Garnica in her e-mail:

- The evaluation of bird risk at the site from the proposed evaporation pond
- The water resource impacts
- The impact of nitrogen deposition

Note: the location of the comment within Dr. Smallwood's letter is referenced for easier cross-reference.

ISSUE 1: THE EVALUATION OF BIRD RISKS AT THE SITE FROM EVAPORATION POND (PG. 6, ITEM 1)

Dr. Smallwood's letter states that the ponds (referring to the two ponds at BEP I) would draw a large number and variety of migrating and resident birds to their deaths because they are likely to contain toxic substances. The potential for BEP II's evaporation pond

to act as an ecological sink was evaluated by staff and was evaluated on the evidence as part of the Commission Decision on BEP I. Since the first proceeding ended in March 2001, compliance documents from BEP I have been submitted to the Energy Commission and other agencies which improved our knowledge of the risk. The number of birds at risk has been made clearer based on the bird monitoring at the BEP I's evaporation ponds in 2003 and 2004, and monthly testing for selenium, arsenic and chloride in water samples. In addition, since 2001, staff has continued to research new technologies to avoid impacts, but unfortunately has not found a reliable control that avoids airport safety concerns. Under CEQA guidelines, it is always preferable to choose avoidance of the impact first, and mitigation of the impact second. Thus, staff recommends the removal of the evaporation pond from the design or filtration of the wastewater stream, or any other design which avoids hazardous exposure. Without a new design, the proposed project causes an impact that is both significant and unmitigated, and habitat mitigation would be unlikely to reduce the impact to less than significant levels.

ISSUE 2: THE WATER RESOURCE IMPACTS OF THE PROJECT (PG. 6, ITEM 2)

Dr. Smallwood criticized staff for not considering the desiccation of surface water bodies in the region by the proposed project (referring to BEP I). On both BEP I and BEP II, the drawdown of the local surface water bodies was considered in staff documents as insignificant and unlikely to cause biological impacts. The groundwater is currently 80 to 90 feet below the surface on the mesa, and there are no nearby streams or water bodies. A measurable drawdown from this project on the Colorado River is unlikely in context of the volume of water used by the Palo Verde Irrigation District (PVID). The nearest well identified by the Applicant, the Sun World well, would only experience 2.2 feet of drawdown, according to the Applicant's analysis. The average drawdown at the Thermal King shop well, the nearest well identified by staff, would be 3.8 feet, increasing to 4.5 feet during maximum-rate pumping. However, water levels in wells located in the Palo Verde Valley would probably not be affected because groundwater recharge from PVID irrigation with Colorado River water would maintain groundwater levels within the valley. More detailed analysis can be found in the **SOIL AND WATER RESOURCES** analysis. Staff does not see these minor drawdowns as causing significant impacts to biological resources, and does not propose any mitigation.

ISSUE 3: THE EFFECT OF NITROGEN DEPOSITION (PG. 7, ITEM 4)

Dr. Smallwood stipulated that staff's review of the nitrogen additions from BEP I were inadequate. Dr. Smallwood's letter assumes there are no other nitrogen sources in the Blythe vicinity and thus any contribution by the proposed project would be a 100% increase. However, combustion from cars and heavy-duty vehicles that travel along Interstate 10 are a substantial source of both nitrogen and ammonia. BEP II emissions, if left unmitigated, would increase ambient levels at the site and immediate area by around 19% to 3.949 kg/ha-yr (see Cumulative Impact section above for more analysis). Nitrogen oxide increases are proposed to be offset by the purchase of nitrogen-based Emission Reduction Credits within the air basin (BEP II 2002a, Table 7.7-25; MDAQMD 2004a, Table 7).

Dr. Smallwood proposed in his letter that land be acquired to mitigate the effects of nitrogen deposition. His proposal was that the amount of mitigation land be calculated based on the outer-most contour found on the nitrogen modeling maps. In other Energy Commission proceedings, such as that for the Metcalf Energy Center, staff requested a combination of Emission Reduction Credits and mitigation land to offset impacts. Staff's formula to determine the amount of mitigation land to be protected was based on the measurable deposition of nitrogen on critical habitat for a federally-listed species. Because there is no measurable deposition of nitrogen on critical habitat in this proceeding, only Emission Reduction Credits are requested by staff in the **AIR QUALITY** analysis (Condition of Certification **AQ-SC-9**). Commission staff determined there were no biological resource impacts resulting from nitrogen deposition on surrounding orchards, highway right-of-ways, substations, and airports. We have a minimal level of concern that nitrogen is being deposited on the native vegetation to the north and northwest of the site, but this impact is only adverse, and not significant. These adverse impacts have already been fully mitigated by the purchase of desert tortoise lands that will be managed to improve conditions for wildlife (see Commission Decision and Amendment Conditions of Certification for BEP I).

SUMMARY

Staff has requested the applicant eliminate the exposure risk created by the project's wastewater stream, which in turn would eliminate the bird mortality concern expressed in Dr. Smallwood's letter. The mitigation for the project proposed in this FSA would be adequate to reduce the potential impacts from water use and nitrogen deposition to less than significant levels without the need for additional off-site habitat compensation.

CONCLUSIONS

The proposed BEP II pond as designed, in conjunction with the high levels of sodium and selenium, is likely to cause on-going significant impacts to birds that cannot be mitigated to less than significant levels except through the elimination of any sodium or selenium exposure. The project as proposed would likely violate the Migratory Bird Treaty Act and Fish and Game Codes 3503, 3503.5 and 3505. Based on the risk factors evaluated, and after input from several agencies, staff recommends that the project owner prepare a new design that ensures birds are not exposed to sodium in excess of 17,000 mg/L or selenium in excess of 0.005 mg/L (or 5 ug/L) concentration from the project's wastewater stream. Staff proposed two initial designs (addition of a ZLD or filtration system to the wastewater discharge) that could meet this criteria, but if the applicant wishes to propose other project design or operational changes that meets staff's criteria, staff is open to evaluating suitable alternatives. All project design changes would have to undergo environmental review prior to Commission approval. An initial analysis of ZLD has been performed by staff in several issue areas and at this cursory level of review it appears that this technology would not create any significant adverse impacts at this location.

On all other project features, staff and various agencies have come to general agreement with the Applicant on the mitigation and compensation that will be necessary to ensure the project is constructed and operated in compliance with various state and federal laws, ordinances, regulations, and standards. Staff concludes that if the

mitigation measures discussed above are made conditions of certification, the project will not result in a significant impact on biological resources. Based on this analysis, and discussions with representatives of other agencies, staff recommends the following Biological Resources Conditions of Certification.

CONDITIONS OF CERTIFICATION

Designated Biologist Selection

BIO-1 The project owner shall submit the resume(s), including contact information, of the proposed Designated Biologist and any Biological Monitor(s) to the Compliance Project Manager (CPM) for approval.

Verification: The project owner shall submit the resume and contact information for the Designated Biologist and Biological Monitor(s) to the CPM at least 60 days prior to the start of any site (or related facilities) mobilization. The Designated Biologist must have a thorough understanding of the Conditions of Certification, the federal and state permits, and the monitoring procedures established in the BRMIMP. Site and related facility activities shall not commence until an approved Designated Biologist is available to be on site and to train all Biological Monitors. Biological Monitor(s) training shall include familiarity with the Conditions of Certification, the federal and state permits, and the monitoring procedures established in the BRMIMP.

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; and
3. At least one year of field experience with biological resources found in or near the project area.

The Biological Monitor(s) shall have a background in biology or environmental science and be approved by the CPM.

If a Designated Biologist needs to be replaced, 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. In an emergency, the project owner shall immediately notify the CPM and submit the qualifications of a short-term replacement. The CPM shall approve the short-term replacement within one business day. The short-term replacement shall have all the duties and rights of a Designated Biologist while a permanent Designated Biologist is proposed to the CPM for consideration.

Designated Biologist and Biological Monitor Duties

BIO-2 The project owner shall ensure that the Designated Biologist and Biological Monitor(s) shall perform the following during any site (or related facilities)

mobilization, ground disturbance, grading, construction, operation, and closure activities:

1. Advise the project owner's Construction and Operation Managers on the implementation of the biological resources Conditions of Certification;

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

4. 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;

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

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

Verification: The project owner shall ensure that the Designated Biologist and Biological Monitor(s) maintain written records of the tasks described above, and summaries of these records shall be submitted in the Monthly Compliance Reports (MCR).

During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report.

Designated Biologist and Biological Monitor Authority

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

If required by the Designated Biologist or Biological Monitor(s), the project owner's Construction/ Operation Manager shall halt all site mobilization, ground disturbance, grading, construction, and operation activities in areas specified by the Designated Biologist as sensitive or which may affect a sensitive area or species.

The Designated Biologist and Biological Monitor(s) shall:

1. Require a halt to all activities in any area when it is determined that there would be an adverse impact to sensitive species 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 shall notify the CPM and project owner 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:

3. 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;
4. Discuss the locations and types of sensitive biological resources on the project site and adjacent areas;
5. Present the reasons for protecting these resources;
6. Present the meaning of various temporary and permanent habitat protection measures;
7. Identify whom to contact if there are further comments and questions about the material discussed in the program; and
8. Include a training acknowledgment form to be signed by each worker indicating that they received training and shall abide by the guidelines.

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 two copies of the proposed BRMIMP to the CPM (for review and approval) and to CDFG and USFWS (for review and comment) and shall implement the measures identified in the approved BRMIMP.

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 resources 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 Incidental Take Permit and Streambed Alteration Agreement and Regional Water Quality Control Board 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 shall 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 if construction will disturb lands outside of the existing permanent fence;
11. If construction will disturb lands outside of the existing permanent fence, then supply aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities - one set prior to any site or related facilities mobilization disturbance and one set subsequent to completion of project construction. 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 permits obtained.

Verification: The project owner shall provide the specified document at least 30 days prior to start of any site (or related facilities) mobilization.

The CPM, in consultation with the CDFG, Western Area Power Administration, 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 five (5) working days before implementing any modifications to the approved BRMIMP to obtain CPM approval.

Any changes to the approved BRMIMP must also be approved by the CPM in consultation with CDFG, Western Area Power Administration, the USFWS and appropriate agencies to ensure no conflicts exist.

Within thirty (30) days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written report identifying which items of the BRMIMP have been completed, a summary of all modifications to mitigation measures made during the project's site mobilization, ground disturbance, grading, and construction phases, and which mitigation and monitoring items are still outstanding.

Construction Mitigation Management to Avoid Harassment or Harm

BIO-6 The project owner shall manage their construction site, and related facilities, in a manner to avoid or minimize impacts to the local biological resources.

Measures to be implemented are:

1. Install a temporarily fence and provide wildlife escape ramps for construction areas that contain steep walled holes or trenches if located outside of an approved, permanent exclusionary fence. The fence around the 66-acre site is an approved, permanent exclusionary fence. The temporary fence shall be hardware cloth or similar materials that are approved by USFWS and CDFG;
2. Ensure all food-related trash is disposed of in closed containers and removed at least once a week.
3. Prohibit feeding of wildlife by staff or contractors;
4. Prohibit non-security related firearms or weapons from being brought to the site;
5. Prohibit pets from being brought to the site;
6. 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. . All incidences of wildlife injury or mortality resulting from project-related vehicle traffic on roads used to access the project shall be reported in the MCR;
7. Minimize use of rodenticides and herbicides in the project area;
8. Cover selected electrical equipment with the potential to electrocute wildlife within the substation with appropriate UV resistant material;
9. Shield lighting to prevent off-site impacts and when night-time construction is approved by the CPM, and then limit its use during night-time construction to only what is necessary to complete the approved work or when worker safety is an issue of concern;
10. Design and install power lines following Avian Power Line Interaction Committee's guidelines;
11. Follow the July 1999 (or most current) desert tortoise handling procedures whenever a desert tortoise is encountered; and
12. Post speed limits for construction-related traffic on Riverside Avenue and take actions against repeat offenders.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP.

Exotic Weed Control Program

BIO-7 During the interim period between the Commission Decision on the project, and the CPM authorization to start construction, the project owner shall follow a weed control program modeled on the "Interim Weed and Erosion Control Prevention Program" adopted for the site by the Blythe Energy Project Phase I.

During construction and operations, a comprehensive exotic weed control program for California Department of Agriculture List A, List B, and Red Alert weeds, shall be implemented at the 66-acre power plant site. This program shall be implemented until such time that the adjacent land use on the north and west sides in no longer a natural community or agriculture, or until the plant is permanently closed. The natural vegetation adjacent to the BEP II site shall be monitored to determine if it has been modified or degraded. Any seed mixture applied following ground disturbance shall be certified as weed-free.

Verification: The project owner shall submit an "Interim Weed and Erosion Control Prevention Program" for CPM review and approval within 90 days of the Commission Decision. The project owner shall be responsible for implementing an approved "Interim Weed and Erosion Control Prevention Program" until they have requested authorization to mobilize at the power plant site from the CPM. Thirty days prior to mobilization, the project owner shall submit a weed control report to the CPM for approval and to Western Area Power Administration for comment. The report shall include photos of the adjacent land or otherwise document any changes in an annual report until such time as the CPM approves cessation. The project owner shall submit the seed mixture to be used following ground disturbance.

Fence Monitoring

BIO-8 The project owner shall conduct maintenance monitoring of the wildlife exclusion fencing on a monthly basis and complete repairs within one week of a problem being identified. Temporary fencing must be installed at any gaps if it shall remain open overnight.

Verification: The project owner shall submit records of all monitoring dates, identify the locations that required repair, and any corrective actions taken in the MCR and Annual Compliance Report.

BIO-9 The Designated Biologist or Biological Monitor shall be contacted if wildlife is found within the fenceline during construction and if it does not leave voluntarily without physical contact or harassment within 24 hours of being found. Actions to prevent physical harm to any wildlife from construction equipment shall immediately be taken by on-site staff. The local office of the California Department of Fish and Game shall be contacted if sensitive wildlife is found within the fenceline during operations.

Verification: For any wildlife found within the fenceline during construction a report shall be completed by the Designated Biologist and submitted with the MCR. For any

wildlife found within the fenceline during operations, a report shall be completed by the plant manager and submitted with the Annual Compliance Report.

Burrowing Owl Surveys and Compensation for Impacts

BIO-10 The project owner shall conduct a pre-construction survey(s) for burrowing owl activities to assess owl presence and need for further mitigation. Active burrows shall be monitored by the Designated Biologist or Biological Monitor(s) throughout construction to identify additional losses from nest abandonment. The project owner shall protect lands and enhance or install burrows to compensate for impacts to active burrows at the site, along related facilities, or within 150 feet of these features. The project owner shall protect lands to compensate for permanent losses of potential upland foraging habitat.

Verification: The project owner shall survey for burrowing owl activities to assess owl presence and need for further mitigation 30 days prior to site mobilization. If construction is delayed or suspended for more than 30 days after the survey, the area shall be resurveyed. Surveys shall be completed for occupied burrows at the fenced parcel and for a 500-foot buffer around these features (where possible and appropriate based on habitat). All occupied burrows shall be mapped on an aerial photo. At least 15 days prior to the expected start of any project-related ground disturbance activities, or restart of activities, the project owner shall provide the burrowing owl survey results and mapping to the CPM, Western Area Power Administration, and CDFG.

Based on the burrowing owl survey results, the following three actions shall be taken by the project owner to offset impacts during construction:

1) Where a burrowing owl is sighted:

a) If paired owls are present in areas scheduled for disturbance or degradation (e.g., grading) or within 150 feet of a permanent project feature, and nesting is not occurring, owls are to be removed per CDFG-approved passive relocation. Passive relocation is only acceptable typically from September 1 to January 31, to avoid disruption of breeding activities. The specific dates for acceptable passive relocation are dependent on the end of burrowing owl nesting season during that calendar year.

b) If paired owls are present within 150 feet of a temporary project disturbance (e.g., transmission line stringing), active burrows shall be monitored by the Designated Biologist or Biological Monitor(s) throughout construction to identify additional losses from nest abandonment and/or loss of reproductive effort (e.g., killing of young).

c) If paired owls are nesting in areas scheduled for disturbance or degradation, nest(s) shall be avoided from February 1 through August 31 by a minimum of a 250-foot buffer or until fledging has occurred. The specific dates for acceptable passive relocation are dependent on the end of burrowing owl nesting season during that calendar year. Following fledging, owls may be passively relocated.

2) Based on the actions taken during construction, the project owner shall provide a land protection and monitoring proposal for CPM approval, and to the CDFG for review 60 days prior to commercial operation. The land protection shall be based on the following premises:

a) To offset the loss of active foraging and burrow habitat, the project owner shall provide 6.5 acres of protected lands within the Palo Verde Valley for each pair of owls or unpaired resident bird that was passively relocated or for which project-related disturbance caused nest abandonment and/or loss of reproductive effort (e.g., killing of young). Protection of additional habitat acreage per pair or unpaired resident bird may be applicable in some instances (such as for gross negligence on the part of the project owner or a contractor).

b) To offset the permanent loss of potential foraging and burrow habitat, the project owner must provide 0.5 acre of land within the Palo Verde Valley for every acre of suitable habitat they permanently converted to an unsuitable use (e.g., ponds or buildings) that was within 300 feet of a burrowing owl pair or unpaired resident.

c) The project owner's protected lands shall be within 1,800 feet of occupied burrowing owl habitat.

d) For each occupied burrow destroyed during construction, existing unsuitable burrows on the protected lands shall be enhanced (e.g., cleared of debris or enlarged) or new burrows installed at a ratio of 2:1.

e) The project owner must provide funding for long-term management and monitoring of protected lands based on the Center for Natural Lands Management Property Analysis Record, or similar cost analysis program.

3) Within 30 days prior to the start of commercial operation, the project owner shall submit to the CPM two copies of the relevant legal paperwork that protects lands in perpetuity (e.g., a conservation easement as filed with the Riverside County Assessor), and any related documents which discuss the types of habitat protected on the parcel. If a private mitigation bank is used, the project owner shall provide a letter from the approved land management organization stating the amount of funds received, the amount of acres purchased in long term management, and their location.

Future Work on Cultural Resources Avoidance Area

BIO-11 The project owner shall prohibit habitat disturbance in the Cultural Resources Avoidance Area unless all regulatory parties have been adequately notified in writing and have given approval. The use of light-duty vehicles shall be limited and shall only be operated during the daylight hours. All persons entering the Cultural Resources Avoidance Area must have completed the Worker Environmental Awareness Program.

Verification: A summary of any activities in the Cultural Resource Avoidance Area shall be made part of the annual reporting to the CPM. All dates of entry and purpose, a copy of signed training acknowledgement forms, and a report on any wildlife sightings shall be part of the annual report. The project owner shall notify the CPM, Western Area Power Administration, U.S. Fish and Wildlife Service, and California Department of Fish and Game 60 days prior to any proposed construction in the Cultural Resource Avoidance Area. Thirty (30) days prior to construction, the Cultural Resource Avoidance Area shall be fenced in a manner that excludes desert tortoise with a biological monitor present. A clearance survey for desert tortoises within the fenceline must be completed prior to commencing work within the fenceline. The results of the desert tortoise clearance survey shall be sent to the same parties listed above for review and comment prior to initiating construction within the fenceline.

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BIOLOGICAL RESOURCES APPENDIX A
Food Chain Interruption at Luz SEGS IX and X Evaporation Ponds

Conditions of Certification 11g of the SEGS IX and X Commission Decision specifies that aquatic invertebrates be collected from the evaporation ponds and analyzed each August for selenium. In addition, the Condition states if the selenium concentrations are found to exceed 4 parts per million (ppm) dry weight basis, then California Energy Commission and California Department of Fish and Game (CDFG) are to be notified.

In October 1993, the two agencies were notified that invertebrate samples collected in August 1992 and 1993 exceeded the 4 ppm threshold. The agencies began to review actions that could be taken to reduce potential impact to birds. In January 1994, the CDFG recommended:

1. Maintain ponds free of vegetation; operate ponds so water surface does not fall below the point where the interior slope meets the bottom; maintain safer water depth for birds; remove all accumulated sand and sediment to reduce invertebrate growth.
2. Keep ponds free of algae and other plant growth. Consult with the CDFG prior to the use of any chemicals to control plant growth.
3. Haze birds from the ponds. For hazing to be effective, a clean alternative habitat is necessary.
4. If 1 through 3 is inadequate, then reconstruction of the ponds to increase shoreline slope, and or increase the pond depth will be necessary

The Energy Commission adopted these recommendations and the project owner was asked told to comply with the recommendations.

The project owner immediately took action on Recommendation 1 and no bird nests have ever been found at the site. In addition, in 1994 they began a habitat study of nearby Harper Lake Marsh to comply with Recommendation 3 from the CDFG letter. To complete Recommendation 2, the biologist working for the project owner recommended adding sodium hypochlorite (bleach) to the water. Shock treatment at 10 ppm followed by continual treatment at 1 ppm chlorine was recommended at an estimated annual cost of $77,000. The chlorination program started in December 1994. The chlorination plan proved to be unsatisfactory, and in April 1995, the project owner requested an alternative method to control algae. The proposal was to use chelated copper sulfate solution. The two agencies, and the Lahontan Regional Board, approved the use of a copper solution in July 1995. The August 1995, 1996 and 1997 invertebrate samples again showed selenium was at levels above 4 ppm dry weight. While the selenium levels in some species invertebrates had decreased in some ponds, perhaps due to the copper treatments, there were still algae and invertebrates living in the ponds, and bird use was still steady.

The elimination of algae and invertebrates at the Luz SEGS evaporation ponds was not only costly, but proved to be ineffective. Invertebrates survived both the chlorination and the copper solution treatments and as a result bird use remains steady. It should be noted that all food chain interruption was stopped in 1998 for alternative reasons.11.5

BIOLOGICAL RESOURCES APPENDIX B
The Algal-Bacterial Selenium Removal (ABSR) Process

The most innovative and least costly method known to remove selenium from water is the Algal-Bacterial Selenium Removal (ABSR) Process which began development in the late-1990s. During the past four years, a 20,000 gallon per day ABSR pilot-scale system has been operating in the Panoche Drainage District (San Benito County) where selenium in the water approaches 0.4 mg/L (or 400 ug/L) and salt levels were as high as 22 g/L. The ABSR system has been shown to economically remove 87% of influent total selenium and 95% of influent nitrate (Panoche Drainage District 2001). Not including capital costs, the ABSR Process cleans selenium from water for $200 to $300 per acre-foot water and is far less costly than a reverse osmosis system which costs $500 to $600 per acre-foot (California Bay Delta 2000).

Unfortunately, BEP II wastewater would remain above the "high-risk" threshold of 0.005 mg/L (or 5 ug/L) selenium even with 87% removal efficiency. While the applicant may be able to dilute their waste-stream with production well water to meet the water quality standard, the dilution of a waste-stream is typically discouraged as a matter of policy. SOIL AND WATER RESOURCES staff and Regional Water Quality Control Boards typically evaluate such actions as a non-beneficial use of water. Instead, to bring the wastewater down below the threshold, a final cleaning with a reverse osmosis system would be required. The use of a reverse osmosis system after the ABSR system could be economical at the lower levels of selenium and salt, but staff could not find cost estimates of a dual-system.

The ABSR Process systems use a floating island of filters within an open-air pond coupled with an adjacent drying pond. The introduction of additional open-air ponds and drying ponds (muddy flats) would only further the likelihood of bird-use on the power plant site. The Riverside County Airport Land Use Commission, Department of Transportation, and the Federal Aviation Administration discourage bird attractants near airport runways. Because the use of the ABSR does not reduce the potential for creating a Bird-Aircraft Strike Hazard, staff does not recommend its use at BEP II, but the adjacent BEP I power plant may see a benefit in using this technology.

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CULTURAL RESOURCES

Testimony of Gary Reinoehl

INTRODUCTION

This section identifies potential impacts of the proposed Blythe Energy Project Phase II (BEP II) on cultural resources, as defined under state and federal law. 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 ensuring that impacts are mitigated below a level of significance under the California Environmental Quality Act (CEQA) and under the National Environmental Policy Act (NEPA).

Staff provides a cultural overview of the project, as well as analyses of potential impacts from the project using criteria from CEQA and the National Historic Preservation Act (NHPA). 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 the resources are eligible for either register, staff recommends mitigation that attempts to ensure that no significant impacts will occur and that will reduce impacts to the cultural resource to a less than significant level, if possible.

There is always a potential that a project may impact a previously unidentified resource or may 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 LORS.

FEDERAL

- Code of Federal Regulations, 36 CFR Part 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 Secretary's standards and guidelines are used by federal agencies, such as the Forest Service, the Bureau of Land Management, and the National Park Service. The State Historic Preservation Office refers to these standards in its requirements for mitigation of impacts to cultural resources on public lands in California.
- Code of Federal Regulations, 36 CFR Part 800 et seq., the implementing regulations of Section 106 of the National Historic Preservation Act, 16 U.S.C. § 470 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.

The regulations implementing this act, which were revised in 1997, set forth procedures to be followed for determining eligibility of cultural resources, determining the effect of the undertaking on the historic properties, and how the effect will be taken into account. The eligibility criteria and the process described in these regulations are used by federal agencies. Very similar criteria and procedures are used by the state in identifying cultural resources eligible for listing in the California Register of Historical Resources.

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 the California Register of Historical Resources (CRHR), establishes criteria for eligibility to the CRHR, 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 Environmental Impact Report (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. [The California Energy Commission process is a CEQA equivalent process and Staff Assessments replace the CEQA environmental documents.]
- 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; 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." Subsection (f) directs the lead agency to make provisions for historical or unique archeological resources that are accidentally discovered during construction.
- 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

Riverside County

The County of Riverside protects cultural resources by reviewing development applications for compliance with CEQA. More specifically, the Riverside County Comprehensive General Plan Land Use Standards require the Planning Department to determine whether proposed development will alter or destroy an historical site or an archaeological site, cause a substantial adverse change in the significance of an historical or archaeological resource (cf. California Code of Regulations 15064.5), disturb any human remains, or restrict existing religious or sacred uses.

- Riverside County's General Plan identifies two objectives for Historic and Prehistoric Resources. The first objective requires that significant historic and prehistoric resources are identified and documented, and that there are provisions for the preservation of representative and worthy examples. The second objective recognizes the value of these resources and requires that land uses be assessed for impacts to these resources. Cultural resources technical reports submitted to the County must follow a required outline and the consultant must be pre-qualified to submit reports to the County.
- In addition, Riverside County's Ordinance 578, which was intended to create and protect historic districts within the county, addresses a desire on the part of the County to preserve its heritage. The Ordinance does not specifically address archeological resources or historic resources outside designated districts.

City of Blythe

The General Plan of the City of Blythe establishes four goals for cultural resources (BEP II 2002, Table 7.1-3):

1. To protect and preserve important and unique resources of the City and region, thereby maintaining the City residents and Palo Verde Valley's cultural heritage.

2. Review and evaluate proposals for development to determine the potential for impacts to known and suspected cultural resources of importance, in order to determine mitigation where necessary.
3. Treat archaeological resource information as confidential in order to prevent vandalism and other threats to those resources.
4. Require a professional archeologist be employed to examine and document any resources discovered during construction, and to develop appropriate mitigation measures.

ENVIRONMENTAL SETTING

The project as proposed would be located on the Palo Verde Mesa near to the Blythe Municipal Airport, approximately five miles west of the City of Blythe. The project site consisted of sparsely vegetated desert scrub on relatively flat land. The BEP II project is contained within the western 76 acres of the 152-acre Blythe Energy Project Phase I (BEP I) amended site. The project site is currently private land bordered on the east by the existing BEP I, on the south by Hobsonway a county road, and on the north by Riverside Avenue. The BEP II site has now been partially graded, compacted and stabilized (66 acres) per the conditions of approval for the BEP I amendment (99-AFC-8C). Presently, several electric transmission lines (Blythe-Eagle Mountain, Imperial Irrigation District "F", and Blythe-Knob) consisting of wood pole H-frame structures, cross the property (BEP II 2002, pp. 7.1-1, 7.1-7).

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

Paleo-Indian Period

The first well-dated Native American occupation of the Colorado River Valley is the San Dieguito complex, dating between 7,000 and 12,000 years before present (BP). It is assumed from the material culture remains that these people employed a hunter-gatherer adaptation based on small mobile bands exploiting game and collecting seasonally available wild plants. Settlement patterns indicate sites typically located on mesas and terraces overlooking larger washes and around the edges of lakes. Early San Dieguito tools include bifacial and unifacially reduced choppers and chopping tools, concave-edged scrapers, bilateral-notched pebbles, and scraper planes. Later, finely made blades, smaller bifacial points, and a variety of scraper and chopper types were introduced. Finally, fine pressure flaking techniques, including pressure-flaked blades, leaf-shaped projectile points, scraper planes, plano-convex scrapers, crescents (amulets), and elongated bifacial knives become part of the inventory (CEC 2000, p. 125).

Archaic Period

Few Archaic period sites have been dated in the desert on either side of the Colorado River but sites from this time period date between about 7,000 and 1,000 years BP.

The economy can be seen as exploitation of a variety of food resources, including large and small animals. Generally, the Archaic period in the Western United States saw a diversification of artifact assemblages, including the introduction of the widespread use of ground stone technology to exploit seasonally available seeds and nuts. However, evidence is lacking in the Lower Colorado River area (CEC 2000, pp. 125, 126).

Late Prehistoric Period

The Late Prehistoric period in the lower Colorado River Region has been referred to as "Patayan" first recognized with the introduction of pottery approximately 1,200 years ago. The presence of Desert Side-notched and Cottonwood type projectile points at about 1,500 years BP may indicate an early pre-ceramic phase. The introduction of floodplain agriculture, the bow and arrow, and a change in burial practices characterizes this period. Population growth, along with more sedentary villages, resulted from a heavy reliance on grown foods rather than wild foods. An extensive trail system across the desert was established that linked the Lower Colorado River peoples with related groups in the greater Southwest, the Gulf of California and the Pacific Ocean. Trails are often associated with ceramic "pot-drops," shrines, and other evidence. Many of the Colorado Desert pictographs, petroglyphs, and bedrock grinding surfaces are also associated with the Patayan pattern. Away from the Colorado River, higher elevations were used for desert resource collection, particularly during periods of flooding. Wild foods are estimated to have accounted for 40 to 70 percent of the diet (CEC 2000, p. 126).

ETHNOGRAPHIC BACKGROUND

Several ethnohistoric and contemporary Yuman and Numic speaking peoples trace heritage ties to the lower Colorado River region. Yuman groups included the Mojave, Quechan, Hualapai, Havasupai, Yavapai, Kamia, Maricopa, Halchidhoma, Cocopah, and Paipai. Numic groups include the Chemehuevi and the closely-related Southern Paiute. Warfare and migration characterized this period and population boundaries shifted regularly. Before about 1700, the exact group occupying the project area is unknown but it is likely that it was the Maricopa. Sometime after 1700, the Halchidhoma settled the area, living tenuously between the powerful and militant Quechan to the south and the Mojave to the north.

Halchidhoma and Maricopa may be regarded as closely related; the two groups interacted extensively and spoke similar dialects. These two groups were also similar in many ways to the Quechan and the Mojave. The Quechan lived in dispersed rancherias along the Colorado River north and south of the confluence with the Gila River. Like the Mojave, large permanent semi-subterranean houses were occupied in the winter, and ramadas or brush shades were used in the summer. Under constant attack by the Quechan and Mojave, the Halchidhoma fled the area for northern Mexico and then the Gila River around 1828. The aggressive Mojave followed them into their former territory and occupied it briefly. The "core" area of the Mojave was the Mojave Valley but did extend north to Old Cottonwood Island, about 15 miles north of Davis Dam, and as far south as the Colorado River Indian Reservation when they were first encountered by the Juan de Oñate expedition in 1604. Occasionally and intermittently they controlled areas as far south as Palo Verde. The Mojave later invited another of their confederates, the Numic speaking Chemehuevi, to settle the area.

The Chemehuevi (and Southern Paiute) were organized into small, mobile groups whose settlement patterns were influenced heavily by seasonal availability of plant resources. Chemehuevi groups moved throughout the desert to exploit plant resources as they became available. They fragmented into nuclear families when food was scant or dispersed but also came together on occasion for game drives. They resided in the Chemehuevi Valley and the Colorado River Valley by 1859. When Chemehuevi groups gained access to land on the Colorado River, they quickly adopted floodwater farming. This group dominated until displaced by Euro-American settlement.

The Halchidhoma, Maricopa, Mojave, Quechan, Chemehuevi, and other groups of the lower Colorado River region shared traits including patrilateral or bilateral descent, an emphasis on personal dreams, cremation of the dead, and floodwater agriculture. They typically lived in settlements widely scattered over the floodplain and adjacent low terraces of the Colorado River. Adjacent higher terraces were used for hunting and gathering wild desert foods. Annual flooding deposited layers of rich silt and provided for the growing of crops such as maize, tepary beans, pumpkins, gourds, and sunflowers. Later, Euro-Americans introduced wheat, barley, muskmelons, and cowpeas. People relied to some extent on stored supplies of maize and beans, as well as wild foods of the desert. Important wild foods included mesquite, screwbean, tule roots and sprouts, chia, yucca fruits, and agave. Rabbits, squirrels, chipmunks, gophers, woodrats, quail, duck, mudhen, and pigeon were hunted for meat, as well as large game such as deer and mountain sheep. Fishing was also common in the late summer when the river receded.

In addition to local resources, people relied to some degree on regional exchange of goods. The Quechan traded pumpkins, beans, melons, gourds, and maize and received rabbit skin blankets, baskets, buckskins, mescal and finished leather goods from the Yavapai, woven blankets from the Hopi, acorns from the Kumeyaay and Cahuilla, eagle feathers from the Mojave, and tobacco from the Kamia or eastern Kumeyaay.

Yuman contact with Europeans first occurred in 1540 when Hernando de Alarcon sailed up the Colorado River to near present-day Yuma, Arizona. However, missions were not established in the region until the late eighteenth century. Once European settlement occurred, conflicts increased in scale and frequency (CEC 2000, pp. 126, 127).

HISTORIC SETTING

Europeans first entered what is now southeastern California in 1540 when Hernando de Alarcon sailed up the Colorado River from the Gulf of California to the vicinity of present day Yuma, Arizona. They met and interacted with the Yuman speaking Native Americans who had occupied the area for some time. Contact between these groups continued over the next two centuries, but the Spanish largely focused their colonizing efforts on areas to the south and east. It was not until missions were established in the region in the late eighteenth century that Yuman cultures were directly affected by Spanish incursion. Conflicts increased in scale and frequency, but the Yumans resisted Spanish domination (CEC 2000, pp. 127, 128).

Anglo-American settlers entered the region following the Mexican War and the Gold Rush in the late 1840's. Fort Yuma was established in 1852 and six years later, the U.S. Army defeated the combined forces of the Mojave and Quechan. Following the pacification of the region, miners, farmers, and cattle ranchers arrived in increasing numbers (CEC 2000, p. 128).

In 1874, San Francisco millionaire Thomas H. Blythe applied for land rights in the Palo Verde Valley region of the Colorado River Valley under California's Swamp and Overflow Act of 1868, which gave land that was perennially swamp or subject to flooding to anyone who would fill, drain, or put the land to good use. Blythe later obtained 35,971 additional acres under the Federal Desert Land Act in 1877, becoming the dominant private land owner in the valley. Blythe applied for 190,000 miner's inches of Colorado River Water on July 17, 1877, increasing the amount to 385,000 miner's inches by February 15, 1883. In 1879, civil engineer Oliver P. Callaway, partner of Blythe, began digging canals and set up an experimental farm, known as the Colorado Colony. This marked the beginnings of irrigated agriculture in the Palo Verde Valley. By 1904, the town of Palo Verde was a small hamlet, and a store and post office were established. Steamboats along the Colorado River were the primary means of transportation to and from Blythe until 1908, when the Laguna Dam was built above Yuma. Stages handled the need to move people and goods thereafter. However, despite growth, flooding of the Colorado River continued to impede agricultural efforts. It was not until the mid-1930s and the construction of Hoover Dam that flooding was finally controlled (CEC 2000, p. 128).

Transportation routes were continually improved. The railroad had never entered the valley so overland transportation was dominated by roads and trails. Finally, a railroad spur was built to Blythe Junction, and it was extended to Blythe itself in 1915. Most early roads followed the railroad tracks or old wagon roads. The federal highway, now Interstate 10, was paved from Indio to Blythe in 1936 (CEC 2000, p. 128).

During the Depression of the 1930s, many farmers and farm laborers from the dust bowl came to California, including the Palo Verde Valley, looking for work in agriculture, mining or other laboring professions. Several large water projects, such as the All-American Canal, were undertaken with the help of the large pool of inexpensive labor. At the start of World War II, the Blythe Municipal Airport was taken over by the U.S. Army and designated Morton Air Academy; 650 buildings and 8,000 foot long runways were constructed. The airport became the home to the 390th Bomb Group, consisting of four squadrons of B-17 Flying Fortresses. The Air Academy served about 8,000 men and several hundred WACs. Wives and families of servicemen swelled the population of Blythe to over 4,000, many living in box cars, sheds, spare rooms, and empty buildings (CEC 2000, p. 128).

During the same period, the U.S. Army Ground Forces established the Desert Training Center (DTC) that was renamed the California-Arizona Maneuver Area (C-AMA) in 1943. The DTC/C-AMA was an armored training facility for the preparation of troops for the invasion of North Africa. The facility covered over 18,000 square miles and served in excess of one million troops. The Blythe Army Air Base, in the middle of DTC/C-AMA, was likely used for transportation and supply purposes. Training at the DTC/C-AMA continued until 1944, and the Morton Air Academy ceased military training

operations in the same year. The airfield returned to its former role as a municipal airport, with much improved runway and support buildings. Portions of the facility have been used by Palo Verde Valley High School, and later Palo Verde College. The barracks were used as dormitories by the male college students until the college found new facilities (CEC 2000, pp. 128, 129). Few of the structures of the Morton Air Academy still exist. The most prominent building in the area of the airfield is a hanger.

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 at the Eastern Information Center of the California Historic Resources Information System (CHRIS) located at the University of California, Riverside on September 8, 1999 (BEP II 2002, Appendix 1). The records searches included the energy center site and one mile radius around the project site (BEP II 2002, p. 7.1-8, Appendix 7.1). Several surveys were conducted in conjunction with the BEP I.

The surveys included the 76-acre parcel for the BEP I (east half of the original 152 acre project area), the 76-acre expansion area (west half of the original project area), and an area along and to the north of Riverside Drive. Table 1 indicates the resources that were recorded and their status. Government Land Office maps depicting 19th century features were checked for pertinent features that could be considered cultural resources. Only one trail was noted that is about five miles east of the project area.

BEP Plant Site

As part of the BEP I, the Request to Add 10 Acres to the Site of the Blythe Energy Project (99-AFC-8C) and the Proposed Amendment to Place Earth Fill from the Blythe Energy Project (99-AFC-8C) an intensive pedestrian survey of the property was completed. The survey of the 76-acre BEP I site revealed four historic sites and two isolated prehistoric artifacts (Table 1). The two isolated prehistoric artifacts found on the plant site consist of a single flake and core of chert. Four archeological deposits (the historic period sites CA-RIV-6366H, -6367H, -6368H, and -6369H) recorded in the BEP I site area were determined to not meet the criteria for eligibility for the CRHR (Table 1) (BEP II 2002, p. 7.1-8; CEC 2001a, p. 217). These four deposits were destroyed as part of the BEP I development and will not be discussed further in this analysis.

Two archeological deposits, CA-RIV-6725H and –6370H, were recorded within the BEP I expansion areas (10 Acre and Earth Fill Amendments) and are within the proposed BEP II plant site. The recording and subsurface testing of CA-RIV-6725H recovered the information values that the deposit contained. Consequently, the deposit no longer meets the criteria for eligibility for the CRHR (BEP 2002, p. 7.1-12; CEC 2001b, p. 3).

Table 1 Cultural Resources within the Blythe Energy Center Phase I		
Resource Designation	Site Type	Previous determination of Eligibility
CA-RIV-6366H	Refuse scatter	Not eligible (BEP I)
CA-RIV-6367H	Refuse scatter	Not eligible (BEP I)
CA-RIV-6368H	Refuse scatter	Not eligible (BEP I)
CA-RIV-6369H	Refuse scatter	Not eligible (BEP I)
CA-RIV-6370H	Refuse scatter	Potentially eligible, federal MOA (BEP I Am.*)
CA-RIV-6725H	Refuse scatter	Not eligible (BEP I Am.*)
P-33-9187	Isolated flake	Not eligible (BEP I)
P-33-9189	Isolated core	Not eligible (BEP I)
Blythe Airport	WWII air base	Recommended eligible, setting diminished (BEP I)
Parker-Blythe No. 1 and No. 2 lines	Transmission line	Not eligible (BEP I)
Blythe-Knob line	Transmission line	Not eligible (BEP I)
Imperial Irrigation District "F" line	Transmission line	N/A (BEP I)

* BEP I Amendment to place earth fill from the Blythe Energy Project (CEC 200b1, pp. 3, 4)

Since this site was analyzed and treated as part of the BEP I amendment, it will no longer be discussed as part of this project.

CA-RIV-6370H is a large historic period deposit associated with the historic military use of the Blythe Army Air Base and/or the Desert Training Area. Extensive testing was conducted at CA-RIV-6730H and the applicant provided a draft report indicating that the deposit was eligible for the NRHP and consequently the CRHR. The southern portion of the CA-RIV-6370H within the project boundary consists of landform modifications (grading, trenching, and push piles) with few artifacts. The northern portion of the CA-RIV-6370H within the project boundary consists of trenches, push piles, holes, dirt piles, and many artifacts.

Western Area Power Administration (Western) as the lead federal agency consulted with the California State Historic Preservation Officer (CA SHPO) in accordance with their Section 106 responsibilities under the National Historic Preservation Act for the expansion area. The CA SHPO did not agree that CA-RIV-6370H was eligible for the NRHP and requested additional information. A Memorandum of Agreement was signed by the owner of BEP I, the property owner of the expansion area, the CA SHPO and Western to fulfill Western's obligations under the federal regulations. The eligibility of CA-RIV-6370H was to be resolved as part of the agreement (BEP II, 2002, p. 7.1-14).

The Energy Commission staff stated in the amendment analysis, based on the draft testing report, that the information was not sufficient to clearly conclude that CA-RIV-6370H is eligible for the CRHR. CA-RIV-6370H is being treated as eligible until such time that the research design, background research and analysis of artifacts is completed and the determination of eligibility for the NRHP and CRHR can be clearly made in accordance with Cul-12 of the BEP I amendment that added a 66-acre area for deposit of excess sediments.

The artifacts and landform alterations that make up the southern portion of CA-RIV-6370H were recorded so that any values that might be contained in the deposit and landscape modifications were recovered. Documentation that sufficient information was gathered to complete a report on the southern portion of CA-RIV-6370H has been provided to the Energy Commission. The final report on the southern portion of the site was accepted on May 21, 2003.

BEP I provided a report on April 24, 2003, to comply with Cul-12 of the Conditions of Certification and Stipulation E of the Memorandum of Agreement for Western (BEP I, 2002, confidential). Staff requested additional clarification regarding the report. No response has been received leaving the conditions and stipulations still not completed, and the eligibility of CA-RIV-6370H unresolved.

The BEP I project also provided an inventory and evaluation of buildings and structures from the historic period. The inventory included all structures more than 45 years old within a mile of the BEP I project. Three transmission lines (Table 1) were evaluated as not meeting the eligibility criteria for either the NRHP or the CRHR (CEC 2001a, p. 220).

The Blythe Airport was recommended as eligible for the NRHP by the BEP I for its role in World War II activities as Morton Air Base. The setting for the air base has been altered by removal of buildings at the base, intrusions of center-pivot irrigation fields, construction of the Interstate, and the addition of a residential area nearby (CEC 2001a, p. 220). Because the setting and feeling (aspects of integrity) were already diminished, the construction of the BEP I power plant was not considered a significant impact on the Blythe Airport.

Field Surveys

Field surveys of the project area were completed within the last five years. No additional field surveys were required for the BEP II plant site by the Energy Commission or Western.

Native American Contacts

Energy Commission staff contacted the Native American Heritage Commission (NAHC) on August 20, 2002, to obtain a list of Native Americans to be contacted for the project area. The NAHC provided names of contacts for Riverside County (NAHC 2002). The Energy Commission sent letters to the individuals and tribes on the list from the NAHC on January 8, 2002. The letters requested information regarding resources that could be impacted by the project and concerns regarding those possible impacts. No responses have been received. Western and the Energy Commission staff prepared to jointly consult with the interested Native American groups to avoid any potential undue burdens to the Native American groups.

An ethnographic study was provided to the Energy Commission and Western in accordance with Cul-15 of the BEP I amendment that added a 66-acre area for deposit of excess sediments. Five tribes agreed to participate in the study. The text of the ethnographic report indicates that it is for the BEP I and BEP II projects. However, the interview questionnaire, Attachment A of the report, sent to the Native American groups clearly states that it is for the Blythe Energy Project (Blythe I). The author of the

ethnographic report states that it can be inferred that tribal comments are relevant to both phases of the Blythe Energy Projects (BEP II 2003u, confidential). No explanation is given for how the inference would be made. Staff can only speculate that the author may have provided information about both phases of the project to all the Native American groups that were contacted.

The Halchidhoma-Maricopa people have provided information to others indicating that there may be burial and cremation sites in the vicinity of Palo Verde Mesa. Areas sacred to them are also within the area studied (BEP II 2003u, confidential).

The Quechan also identified this as an area where ceremonial activities take place. This study identifies the location of the Blythe Energy project as “clearly within a highly significant portion of the traditional Yuman, especially Quechan, cultural landscape.” The Quechan indicated that within the study area there are sacred areas where physical residues of human use or occupation may or may not be present (BEP II 2003u, confidential).

The Chemehuevi people regard this area as part of a landscape containing places, landmarks, natural geophysical features and sites that are important to their history and identity. They are concerned about preservation of land, plants, water, minerals and sacred places within this landscape. A portion of the Salt Song Trail crosses the Palo Verde Valley, and the physical trail route is considered sacred by some of the Chemehuevi (BEP II 2003u, confidential).

Similar comments have been provided in ethnographic reports for nearby projects, identifying similar resources, sacred areas and concerns regarding development in this area (Woods 2001, confidential).

CATEGORIZATION OF IDENTIFIED CULTURAL RESOURCES

Various laws apply to the treatment of cultural resources. These laws require the Energy Commission 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. Federal laws apply when a federal agency takes an action. The project will interconnect with a Western owned substation. As a result, Western qualifies as a federal agency taking an action. Western will ensure compliance with federal regulations.

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, they are afforded certain treatment under the National Historic Preservation Act. If the resources are determined significant, and therefore eligible for the CRHR, then mitigation measures are implemented under CEQA to reduce the impact to less than significant if possible. Federal agencies are responsible for meeting

the requirements of NHPA and the Energy Commission is responsible for meeting the requirements of CEQA.

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

a) are associated with events that have made a significant contribution to the broad patterns of our history; or

b) that are associated with the lives of persons significant in our past; or

c) that embody the distinctive characteristics of a type, period, or method of construction, or that represent the work of a master, or that possess high artistic values, or that represent a significant and distinguishable entity whose components may lack individual distinction; or

d) that have yielded, or may be likely to yield, information important to history or prehistory.

California has adopted a similar set of criteria for assessing resources for the California Register of Historical Resources. An historical resource must be significant at the local, state, or national level under one or more of the following criteria:

1. it is associated with events that have made a significant contribution to the broad patterns of local or regional history, or the cultural heritage of California or the United States;
2. it is associated with the lives of persons important to local, California, or national history;
3. it embodies the distinctive characteristics of a type, period, region, or method of construction, or represents the work of a master or possesses high artistic values; or
4. It has yielded, or has the potential to yield information important to the prehistory or history of the local area, California or the nation.

Under federal law, cultural resources determined not to be significant, that do not meet the eligibility criteria for National Register 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 involved federal agencies evaluate the survey reports and site records for any known resources located within or adjacent to the project Area of Potential Effects (APE) to determine whether they meet the eligibility criteria.

The record and literature search and the pedestrian surveys of the proposed project 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 NHPA.

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" (Cal. Code Regs., tit. 14. §15064.5). The guidelines provide a definition for historical resources and set forth a listing of criteria for making this determination (Cal. Code Regs., tit. 14 § 15064.5). 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 (Cal. Code Regs., tit. 14 § 15064.5).

CEQA also contains a section addressing "unique" archeological resources and provides a definition of such resources (PRC, § 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 (Cal. Code Regs., tit. 14 § 15064.5).

The background research revealed that the Blythe Airport was recommended as eligible for the NRHP by BEP I for its role in World War II activities as Morton Air Base. There has been little change in the area since the BEP I proceedings, with the exception of the construction of BEP I which alters the setting and feeling of the Morton Air Base to a small degree. The setting for the air base has been altered by removal of buildings at the base, intrusions of center-pivot irrigation fields, construction of Interstate 10, and the addition of a residential area nearby (CEC 2001a, p. 220).

Western Area Power Administration (Western), as the lead federal agency, consulted with the California State Historic Preservation Officer (CA SHPO) in accordance with its Section 106 responsibilities under the NHPA for the BEP I project. The CA SHPO did not agree that CA-RIV-6370H was eligible for the NRHP and requested additional information. A Memorandum of Agreement (MOA) was signed by the owner of BEP I, the property owner of the expansion area, the CA SHPO and Western to fulfill Western's obligations under the federal regulations. The eligibility of CA-RIV-6370H is to be resolved as part of the MOA (CEC 2001b, pp. 3, 4).

The Energy Commission staff stated in the Staff Analysis of the Proposed Amendment to Place Earth Fill From the Blythe Energy Project (99-AFC-8C), based on the draft testing report, that the information was not sufficient to clearly conclude that CA-RIV-6370H, a historic World War II era trash dump, is eligible for the CRHR. CA-RIV-6370H is being treated as eligible until such time that the research design, background research and analysis of artifacts is completed and the determination of eligibility for the NRHP and CRHR can be clearly made. The northern portion of the site within the expansion area has been fenced to limit access and protect the resource (CEC 2001b,

pp. 3, 4, 6, 8). The southern portion of the site has been recorded and graded. The southern portion of the CA-RIV-6370H has been mapped, described, and photographically recorded (CEC 2001b, pp. 4, 6). The final report on the southern portion of the site was accepted by the Energy Commission on May 21, 2003.

Comments provided by Native American individuals and groups regarding the BEP I project state that there are sacred resources in the vicinity of the proposed BEP II plant. Additional Native American consultation for the proposed project may be conducted by Western. The consultation is intended to identify sensitive resources that could be impacted by the project.

ANALYSIS AND IMPACTS

Since project development and construction usually entail surface and subsurface disturbance, the proposed BEP II 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

Only impacts to eligible cultural resources sites can be potentially significant. The Blythe Airport was recommended as eligible for the NRHP by the BEP I for its role in World War II activities as Morton Air Base. The setting for the air base has been diminished by removal of buildings at the base, intrusions of center-pivot irrigation fields, construction of Interstate 10, the addition of a residential area nearby, and the construction of BEP I. The alteration of the setting for the proposed BEP II project would not be sufficient to materially impair the eligibility of the Morton Air Base.

Energy Commission staff stated in the Staff Analysis of the Proposed Amendment to Place Earth Fill From the Blythe Energy Project (99-AFC-8C) that the information was not sufficient to clearly conclude that archeological site CA-RIV-6370H is eligible for the CRHR or the NRHP. CA-RIV-6370H is being treated as eligible until such time that the research design, background research and analysis of artifacts is completed and the determination of eligibility for the NRHP and CRHR can be clearly made. BEP II has

agreed to restrict all activities within the fenced portion of CA-RIV-6370H; that is, the intact portion of the site on their property (CEC 2003).

Western may continue consultation with Native Americans to identify and evaluate resources and the impacts of the proposed project. The ethnographic report indicated that sacred resources in the vicinity of the project would be impacted. Native Americans have provided recommendations regarding mitigation for the impact of the project on sacred resources. Native American tribes recommended that the five culturally affiliated Indian Tribes be allowed access to the BEP I and II sites for the purpose of allowing traditional leaders to bless the area and conduct the other appropriate ceremonies. They also recommended that the tribes continue to receive any and all information updates regarding any future planned activities related to the Blythe Energy Projects. This information would include any proposed expansion, construction, improvement, refurbishing, or other such activities that might result in an expansion of the project site boundaries. The recommendations also include other tribes that are likely to be indirectly affiliated with the BEP project areas, such as the Tukic-speaking Cahuilla groups, Yuman-speaking Cocopah, Kumeyaay, Pai, and Yavapai tribes, the Twenty-nine Palms Band of Mission Indians (Chemehuevi) and Maricopa members of the Gila River and Ak-Chin Pima-Maricopa Indian Community (BEP II 2003u, confidential).

The City of Blythe has indicated in a public workshop that they are not requiring any ground disturbing activities outside of the project site. BEP II is providing funding to the City of Blythe for their use to spend on improvements or other projects unrelated to the project and the City will conduct the environmental review for all projects related to this funding. Any changes that may be required in the City of Blythe General Plan or other planning documents would trigger the provisions of SB 18. Senate Bill 18, signed into law by Governor Arnold Schwarzenegger in September 2004, requires cities and counties to notify and consult with California Native American Tribes about proposed local land use planning decisions for the purpose of protecting Traditional Tribal Cultural Places ("cultural places").

Water Conservation Offset Plan

The applicant has proposed a Water Conservation Offset Plan (WCOP) that would fallow land that has been under agricultural use within the last five years to offset the project's annual use of approximately 3,300 acre-feet water pumped as groundwater from wells at the plant site. The information provided by the applicant indicates that a value of 4.2 acre-feet of water per acre of land fallowed would be used to calculate the number of acres that would need to be fallowed to offset the project’s water use.

Resources in the area of the WCOP have not been identified. The plan is not sufficiently defined to assess potential impacts to cultural resources. If the WCOP or associated mitigation results in the disturbance of previously undisturbed land, then there is a potential for impacts to cultural (archeological or culturally important) resources. A record search of the proposed area of the WCOP and consultation with Native American groups would be required and surveys of specific areas of ground disturbance would be needed to analyze the impacts.

CUMULATIVE IMPACTS

Imperial Irrigation District and the Bureau of Land Management are in the process of preparing a joint Final Environmental Impact Report/Environmental Impact Statement (FEIR/EIS) for an alternative transmission line between Blythe and either Palm Springs or Niland, both of which have large substation facilities. BEP I has also proposed the construction of a transmission line from the Buck Boulevard Substation to the Julian Hinds Substation and one from the Buck Boulevard Substation to the Midpoint Substation. Transmission lines would cross areas where many cultural resources exist. This could result in indirect impacts to resources. Impacts identified in the ethnographic report required for the BEP I project would be increased. The ethnographic report did discuss concerns over cumulative impacts. The recommendations for mitigation appear to address direct as well as cumulative impacts (BEP II 2003u, confidential).

FACILITY CLOSURE

At the time of planned closure, all then-applicable LORS will be identified and the closure plan required by the Energy Commission 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.

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.

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

COMPLIANCE WITH APPLICABLE LORS

Riverside County and the City of Blythe 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. The property is within the incorporated boundaries of the City of Blythe. The General Plan requirements of the City are consistent with CEQA and the proposed Conditions of Certification. None of the resources identified are within designated districts for Riverside County. If there is work required by the City of Blythe that is outside of the incorporated boundaries, then the requirements of the County's General Plan would apply. Implementation of the

mitigation measures recommended in the conditions of certification will ensure compliance with state and local LORS.

Western is required to comply with federal regulations requiring them to take into account the impacts of their actions on cultural resources. Western would provide their interconnection agreement with conditions that would have to be fulfilled to reduce the impacts of the undertaking. A letter agreement was executed between Caithness and Western in December 2001, and Caithness provided funding to Western to cover their environmental review process. This agreement expired in December 2003. An amendment to the agreement was executed on November 4, 2004. It extends the funding agreement to December 2005 with an option for a one year extension. Staff proposes a condition of certification that assures that the Energy Commission is informed of BEP II compliance with federal regulations. If the point of interconnection changes to a facility that is not owned or controlled by Western and there are no other federal agencies involved, then federal requirements would not apply.

MITIGATION

For cultural resources, the preferred method of mitigation is for project construction to avoid areas where cultural resources are known to exist, wherever possible. Often however, avoidance cannot be achieved, and other measures such as surface collection, subsurface testing, and data recovery must be implemented for archaeological resources and documentation must be implemented for historical structures. Mitigation measures are developed to reduce the potential for adverse project impacts on cultural resources to a less than significant level, if possible.

APPLICANT'S PROPOSED MITIGATION

BEP II recommends that a Cultural Resources Specialist (CRS) would be retained and would be responsible for supervising all of the cultural resource mitigation procedures. The specialist would receive copies of maps and drawings to understand the areas where surface disturbance would take place. The CRS would be available if archeological materials are discovered during grading. The archeological material would be evaluated by the CRS and a mitigation plan would be implemented if the resource is evaluated as significant. The collected cultural materials would be recovered, analyzed, prepared for curation and delivered to a curation facility.

BEP II 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, the procedures to be followed if such material is discovered, and the legal obligations and penalties. Any archaeological materials collected during the construction monitoring and mitigation program would be curated at a qualified curation facility.

The northern portion of CA-RIV-6370H on the project property would be fenced prior to any ground disturbing activities. Fence construction would be monitored by the CRS and the CRS would collect any cultural materials that are encountered. These materials would be added to the collection (BEP II 2002, pp. 7.1-16, - 7.1-21). BEP II also agreed to accept a condition that would restrict all activities within the fenced area of CA-RIV-

6370H. If BEP II proposes at a later time to use the fenced area, they would have to apply for an amendment (CEC 2003).

STAFF'S PROPOSED MITIGATION MEASURES

Commission staff concurs with the mitigation measures proposed by BEP II for cultural resources and agrees that these measures may reduce the impacts to resources to less than significant. Because specific information on the WCOP has not been provided, it is not possible to assess the impacts or to provide mitigation measures for this aspect of the project.

Staff's proposed conditions are consistent with the applicant's proposed measures. The Applicant's measures are incorporated into staff's proposed Conditions of Certification **CUL-1** through **CUL-10** presented below.

In summary, the conditions require implementation of the following measures. **CUL-1** requires that a qualified cultural resources specialist (CRS) 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.

CUL-2 requires the project owner to provide 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 allows staff to verify that appropriate maps and construction schedule information have been provided to the CRS.

CUL-3 requires that a Cultural Resources Monitoring and Mitigation Plan (CRMMP) is developed that details all required activities that must be completed in order to reduce the impacts to a level that is less than significant. The CRMMP defines the roles and responsibilities of cultural resources personnel and provides timelines for the completion of the required mitigation. The CRS would also obtain Native American monitors to observe work in areas where Native American artifacts are found. The CRMMP requires a discussion of curation specifications, materials to be transferred to a curation facility, and the responsibility of the owner to pay all curation fees.

CUL-4 requires that the project owner provide a Cultural Resources Report (CRR) in Archaeological Resource Management Report (ARMR) format. This report would provide information on all field activities and the findings. The CRR would include all Department of Parks and Recreation (DPR) 523 forms and cultural resource reports not previously provided to the California Historic Resource Information System (CHRIS). Copies of the CRR would be provided to the State Historic Preservation Officer (SHPO), the CHRIS and the curating institution (if archaeological materials were collected).

CUL-5 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-6 requires monitoring of the ground disturbance in undisturbed sediments for the project and a process for reducing monitoring to a level below full time. It also requires monitoring logs and weekly summaries of the monitoring activities. All non-compliance issues have to be reported to the CPM, and a reporting process is required. Any required Native American monitors should be obtained.

CUL-7 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.

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 and the criteria that would make a resource eligible to the CRHR or NRHP. In addition, **CUL-6** ensures that unanticipated impacts to cultural resources are identified.

The CRS, alternate CRS and the CRMs have the authority to halt work so that the applicant has flexibility in construction scheduling. The CRS does not have to be at all active areas of construction at the same time. In order to ensure that an impact can be mitigated to less than significant, the individual on site needs to have the ability to stop construction when a discovery is made, not at a later point in time when the CRS has been contacted and informed about the discovery. This condition has been used with these provisions for over four years and has been effective in minimizing impacts to resources.

An amendment to **Cul-8** would be required prior to allowing any activities within the fenced portion of CA-RIV-6370H or removing a portion of the fence. This condition would also bind any successor to fulfill the requirements of the Memorandum of Agreement between Western and the CA SHPO.

Cul-9 requires the project owner to invite Native American tribes to the BEP II site for the purpose of allowing traditional leaders to bless the area and conduct the other appropriate ceremonies. The blessing and ceremonies are intended to “explain to the land why the project was constructed in that particular place and to restore the spiritual balance that they perceive as being disrupted by the construction and operation of the plant” (BEP II 2003u, confidential). Native American tribes also need to be kept informed of all changes or alterations well in advance so that they may consider the impacts to Native American resources in the area.

Cul-10 requires the project owner to provide copies of all correspondence between the applicant and Western regarding the compliance with Section 106 of the National Historic Preservation Act. If BEP II becomes a signatory to the Memorandum of Agreement for the BEP I project, then this would include copies of correspondence regarding compliance with the stipulations of that agreement.

RESPONSE TO APPLICANT'S COMMENT ON PSA

Comment: The consultation section should summarize all activities for the BEP I and BEP II projects including the ethnographic study.

Response: The consultation section summarizes all activities for the BEP II project. Western is obligated under federal laws to consult with Native American Tribes. Western may continue in this effort to fulfill their obligations. Energy Commission staff relied on the ethnographic report provided under the conditions of certification for BEP I to complete the analysis for BEP II. Condition of Certification **Cul-10** was added to mitigate impacts identified in that report.

Comment: BEP II indicated that they have an active agreement with Western to conduct work for the interconnection.

Response: This is addressed in the section entitled "Compliance with Applicable LORS" on pages 16 and 17.

Comment: BEP II has provided a letter from the City of Blythe stating that they are not requiring work outside of the project area. Without ground disturbance outside of the project area staff should provide conclusions and recommendations.

Response: This is addressed in the section entitled "Project Specific Impacts" on page15.

Comment: The BEP I project has placed a great deal of fill material over the BEP II site, raising the grade by about 5 feet. Given previous cultural resource surveys and the large amount of fill on the construction site, BEP II feels that there is no need for a CRS or CRM.

Response: The conditions of certification have been changed to minimize the requirements of the Cultural Resources Monitoring and Mitigation Plan. Cultural resource monitoring is limited to undisturbed sediments.

Comment: The City of Blythe Project Review Committee has provided a letter with the final conditions. BEP II contends that there are no "off-site" improvements or requirements imposed by the City of Blythe.

Response: This is addressed in the section entitled "Project Specific Impacts" on page 15.

RESPONSE TO INTERVENER'S COMMENT REGARDING CULTURAL RESOURCES

Comment: Additional information regarding cultural resources was provided by the CAlifornians for Renewable Energy, Inc. (CARE) on April 4, 2005. The information refers to at least four adobe buildings and a pyramid in the Lower Colorado River Valley. The description indicates that the adobe buildings and

the pyramid are now ruins, if portions of the structures still exist. Attached are a graphic image of intaglios (earth figures) from the Blythe area and a photograph of a feature referred to as "the Throne of Quetzalcoatl." The "Throne of Quetzalcoatl" is noted as a "sacred native cultural resource."

Response: None of the resources referred to in the submittal are described as being within the project site. Cultural resource inventories conducted on the project site did not identify any resources like those described in the intervener's submittal. The nearest structural ruin described in the submittal is about nine miles south of the project area. Since the remains that are described are a ruin, the proposed BEP II project would not materially impair the eligibility of the ruin if it met the eligibility requirements for the CRHR and NRHP.

The graphic image of the intaglios appears to be a composite of aerial images imposed over a background. Information about the locations of the intaglios was not provided in the submittal. Intaglios are known to the local Native American Tribes and are considered extremely sensitive (BEP II 2003u; von Werloff 2004).

Fences can be seen in the images around most of the intaglios. There are some intaglios north of the City of Blythe on property administered by the Bureau of Land Management (BLM). The intaglios on BLM land are fenced to restrict pedestrian and vehicular traffic to limit deterioration of the designs. The proposed facility is at least ten miles from the intaglios that are north of Blythe and the facility is not visible from the intaglios.

The record search for the BEP I and II project sites did not identify intaglios within one mile of the project area. The ethnographic study for the BEP I plant indicated that there are sensitive resources that would be impacted by the construction of the proposed project. These sensitive resources could be intaglios and mitigation measures were provided in the ethnographic report (BEP II 2003u). No impact analysis or mitigation measures were provided in the intervener's submittal and the information provided was not sufficient to determine that the project impacts were different from the analysis in the previous section of this document. Considering the other recent developments near the BEP II site (Interstate 10, BEP I, the Blythe Municipal Airport, Nicholls Warm Springs and the City of Blythe), any changes in setting and feeling of intaglios within the view of the proposed project would be not be sufficient to materially impair the eligibility of the resource if it meets the eligibility criteria for the CRHR and NRHP.

The "Throne of Quetzalcoatl" is about four miles from the proposed project site. Interstate 10 is just to the south of the "Throne of Quetzalcoatl". To the east is the Blythe Municipal Airport, Nicholls Warm Springs and the BEP I project site. The addition of the BEP II project would change the setting to a small degree. However, the setting to the east of the "Throne of Quetzalcoatl" has been significantly changed. The change in setting to the "Throne of Quetzalcoatl" would not be changed sufficiently to materially impair the eligibility of the resource if it meets the eligibility criteria for the CRHR and NRHP.

CONCLUSIONS AND RECOMMENDATION

If a resource meets the eligibility requirements, then mitigation measures would be developed to reduce the impacts. Staff's proposed Conditions of Certification **Cul-1** through **Cul-7** would reduce the impacts to buried archeological resources to less than significant if any are discovered during construction.

In the event previously unknown cultural resource sites or materials are encountered, or if known resources may be impacted in a previously unanticipated manner, then the project owner would notify the Energy Commission in accordance with **Cul-7**. Mitigation measures required under **Cul-7** would reduce the impacts to less than significant and ensure compliance with applicable laws, ordinances, regulations, and standards.

Cul-8 restricts activities within an identified archeological site unless specifically allowed by the CPM so that impacts to the portion of the deposit within the project area would be less than significant.

Native American tribes have identified significant cultural resources that would be impacted by the BEP II project. **Cul-9** is a measure proposed by the tribes to mitigate the impact.

Cul-10 requires that the Energy Commission be informed of the compliance with federal laws. Although the federal agency is responsible for this compliance, the condition allows the Energy Commission to ensure that the project is in conformance with federal regulations.

Resources in the area of the WCOP have not been identified. The plan is not sufficiently defined to assess potential impacts to cultural resources. If the WCOP or associated mitigation results in the disturbance of previously undisturbed land, then there is a potential for impacts to cultural (archeological or culturally important) resources. A record search of the proposed area of the WCOP and consultation with Native American groups would be required and surveys of specific areas of ground disturbance would be needed to analyze the impacts.

PROPOSED CONDITIONS OF CERTIFICATION

CUL-1 Prior to the start of ground disturbance, the project owner shall obtain the services of a **Cultural Resources Specialist (CRS)**, and one or more alternates, if alternates are needed, to manage all monitoring, mitigation and curation activities. The CRS may elect to obtain the services of **Cultural Resource Monitors (CRMs)** and other technical specialists, if needed, to assist in monitoring, mitigation and curation activities. The project owner shall 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) and NRHP. No ground disturbance shall occur prior to CPM approval of the CRS, unless specifically approved by the CPM.

CULTURAL RESOURCES SPECIALIST
The resume for the CRS and alternate(s) shall include information demonstrating that the minimum qualifications specified in the U.S. Secretary of Interior Guidelines, as published in the Code of Federal Regulations, 36 CFR Part 61 are met. In addition, the CRS shall have the following qualifications:

1. The technical specialty of the CRS shall be appropriate to the needs of the project and shall include a background in anthropology, archaeology, history, architectural history or a related field; and

2. At least three years of archaeological or historic, as appropriate, resource mitigation and field experience in California.

The resume of the CRS shall include the names and telephone numbers of contacts familiar with the work of the CRS on referenced projects, and shall demonstrate that the CRS has the appropriate education and experience to accomplish the cultural resource tasks that must be addressed during ground disturbance, grading, construction and operation. In lieu of the above requirements, the resume shall demonstrate to the satisfaction of the CPM and Western that the proposed CRS or alternate has the appropriate training and background to effectively implement the conditions of certification.

CULTURAL RESOURCES MONITOR
CRMs shall have the following qualifications:

1. a BS or BA degree in anthropology, archaeology, historic archaeology or a related field and one year experience monitoring in California; or

2. an AS or AA degree in anthropology, archaeology, historic archaeology or a related field and four years experience monitoring in California; or

3. 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.

CULTURAL RESOURCES TECHNICAL SPECIALISTS
The resume(s) of any additional technical specialists, e.g. historic archeologist, historian, architectural historian, physical anthropologist shall be submitted to the CPM for approval.

The project owner shall submit the resume for the CRS, and alternate(s) if desired, to the CPM for review and approval at least 45 days prior to the start of ground disturbance.

Verification: The project owner shall submit the resume for the CRS, and alternate(s) if desired, to the CPM for review and approval and to Western at least 45 days prior to the start of ground disturbance.

At least 10 days prior to a 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 and to Western.

At least 20 days prior to ground disturbance, the CRS shall provide a letter naming anticipated CRMs for the project and stating that the identified CRMs meet the minimum qualifications for cultural resource monitoring required by this condition. If additional CRMs are obtained during the project, the CRS shall provide additional letters to the CPM and Western identifying the CRMs and attesting to the qualifications of the CRM, at least five days prior to the CRM beginning on-site duties. At least 10 days prior to beginning tasks, the resume(s) of any additional technical specialists shall be provided to the CPM for review and approval and to Western.

At least 10 days prior to the start of ground disturbance, the project owner shall confirm in writing to the CPM and to Western that the approved CRS will be available for on-site work and is prepared to implement the cultural resources conditions of certification.

CUL-2 Prior to the start of ground disturbance, the project owner shall provide the CRS, the CPM and Western 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 requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the CRS and CPM. The CPM shall review submittals and in consultation with the CRS approve those that are appropriate for use in cultural resources planning activities.

If construction of the project would proceed in phases, maps and drawings not previously provided shall be submitted prior to the start of each phase. Written notification identifying the proposed schedule of each project phase shall be provided to the CRS and CPM and Western.

At a minimum, the CRS shall consult weekly with the project construction manager to confirm area(s) to be worked during the next week, until ground disturbance is completed.

The project owner shall notify the CRS and CPM and Western of any changes to the scheduling of the construction phases. No ground disturbance shall occur prior to CPM approval of maps and drawings, unless specifically approved by the CPM.

Verification:

1. The project owner shall submit the subject maps and drawings at least 40 days prior to the start of ground disturbance to the CPM and Western. The CPM will

review submittals in consultation with the CRS and approve maps and drawings suitable for cultural resources planning activities.

2. If there are changes to any project related footprint, revised maps and drawings shall be provided to the CPM and Western at least 15 days prior to start of ground disturbance for those changes.
3. If project construction is phased owner shall submit the subject maps and drawings, if not previously provided, 15 days prior to each phase to the CPM and Western.
4. A current schedule of anticipated project activity shall be provided to the CRS on a weekly basis during ground disturbance and also provided in each Monthly Compliance Report (MCR).
5. The project owner shall provide written notice of any changes to scheduling of construction phases within five days of identifying the changes to the CPM and Western.

CUL-3 Prior to the start of ground disturbance, the project owner shall submit the Cultural Resources Monitoring and Mitigation Plan (CRMMP), as prepared by the CRS, to the CPM for approval and to Western. The CRMMP shall identify general and specific measures to minimize potential impacts to sensitive cultural resources. Copies of the CRMMP shall reside with the CRS, alternate CRS, each monitor, and the project owner's on-site manager. No ground disturbance shall occur prior to CPM approval of the CRMMP, unless specifically approved by the CPM.

The CRMMP shall include, but not be limited to, the following elements and measures.

1. A proposed general research design for buried Native American deposits that includes a discussion of research questions and testable hypotheses applicable to the project area. A refined research design will be prepared for any resource where data recovery is required.
2. The following statement shall be added to the Introduction: Any discussion, summary, or paraphrasing of the conditions in this CRMMP is intended as general guidance and as an aid to the user in understanding the conditions and their implementation. If there appears to be a discrepancy between the conditions and the way in which they have been summarized, described, or interpreted in the CRMMP, the conditions, as written in the Final Decision, supercede any interpretation of the conditions in the CRMMP. (The Cultural Resources Conditions of Certification are attached as an appendix to this CRMMP.)
3. A discussion of the requirement that all cultural resources encountered shall 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 as specified in the research design 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 Federal Code of Regulations, Part 79.

4. 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.

Verification: The project owner shall submit the subject CRMMP at least 30 days prior to the start of ground disturbance to the CPM and Western. Per ARMR Guidelines the author's name shall appear on the title page of the CRMMP. Ground disturbance activities may not commence until the CRMMP is approved, unless specifically approved by the CPM. A letter shall be provided to the CPM indicating that the project owner would pay curation fees for any materials collected as a result of the archaeological investigations (survey, testing, data recovery).

CUL-4 The project owner shall submit the Cultural Resources Report (CRR) to the CPM for approval and to Western. The CRR shall be written by the CRS and shall be provided in the ARMR format. The CRR shall report on all field activities including dates, times and locations, findings, samplings and analysis. All survey reports, Department of Parks and Recreation (DPR) 523 forms and additional research reports not previously submitted to the California Historic Resource Information System (CHRIS) and the State Historic Preservation Officer (SHPO) shall be included as an appendix to the CRR.

Verification: The project owner shall submit the subject CRR within 90 days after completion of ground disturbance (including landscaping) to the CPM and Western. Within 10 days after CPM approval, the project owner shall provide documentation to the CPM that copies of the CRR have been provided to the SHPO, the CHRIS and the curating institution (if archaeological materials were collected).

CUL-5 Prior to and for the duration of ground disturbance, the project owner shall provide Worker Environmental Awareness Program (WEAP) training to all new workers within their first week of employment. The training may be presented in the form of a video. The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Samples or visuals of artifacts that might be found in the project vicinity;
3. Information that the CRS, alternate CRS, and CRMs have the authority to halt construction to the degree necessary, as determined by the CRS, in the event of a discovery or unanticipated impact to a cultural resource;
4. Instruction that employees are to halt work on their own in the vicinity of a potential cultural resources discovery, and shall contact their supervisor and the CRS or CRM; and that redirection of work would be determined by the construction supervisor and the CRS;

5. An informational brochure that identifies reporting procedures in the event of a discovery;
6. An acknowledgement 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.

No ground disturbance shall occur prior to implementation of the WEAP program, unless specifically approved by the CPM.

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-6 The project owner shall ensure that the CRS, alternate CRS, or CRMs shall monitor ground disturbance of previously undisturbed sediments full time in the vicinity of the project site, linears and ground disturbance at laydown areas or other ancillary areas to ensure there are no impacts to undiscovered resources and to ensure that known resources are not impacted in an unanticipated manner. In the event that the CRS determines that full-time monitoring 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.

CRMs 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. The CRS may informally discuss cultural resource monitoring and mitigation activities with Energy Commission technical staff.

The CRS and the project owner shall notify the CPM and Western by telephone or e-mail of any incidents of non-compliance with the conditions of certification and/or applicable LORS upon becoming aware of the situation. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the conditions of certification.

Cultural resources monitoring activities are the responsibility of the CRS. Any interference with monitoring activities, removal of a monitor from duties assigned by the CRS or direction to a monitor to relocate monitoring activities by anyone other than the CRS shall be considered non-compliance with these conditions of certification.

A Native American monitor shall be obtained to monitor excavations in undisturbed sediments in areas where Native American artifacts are discovered. Informational lists of concerned Native Americans and Guidelines for monitoring shall be obtained from the Native American Heritage Commission. Preference in selecting a monitor shall be given to Native Americans with traditional ties to the area that shall be monitored.

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 or e-mail 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 and to Western. Documentation justifying a reduced level of monitoring shall be submitted to the CPM and Western at least 24 hours prior to the date of planned reduction in monitoring.

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. Copies of daily logs shall be retained and made available for audit by the CPM and Western.

Within 24 hours of recognition of a non-compliance issue with the conditions of certification and/or applicable LORS, the CRS and the project owner shall notify the CPM and Western by telephone of the problem and of steps being taken to resolve the problem. The telephone call shall be followed by an e-mail or fax detailing the non-compliance issue and the measures necessary to achieve resolution of the issue. Daily logs shall include forms detailing any instances of non-compliance. In the event of any non-compliance issue, a report written no sooner than two weeks after resolution of the issue that describes the issue, resolution of the issue and the effectiveness or the resolution measures, shall be provided in the next MCR.

If Native American artifacts are discovered in undisturbed sediments, the project owner shall send notification within one week to the CPM and Western identifying the person(s) retained to conduct Native American monitoring. The project owner shall also provide a plan identifying the proposed monitoring schedule and information explaining how Native Americans who wish to provide comments will be allowed to comment. If efforts to obtain the services of a qualified Native American monitor are unsuccessful, the project owner shall immediately inform the CPM. The CPM will either identify potential monitors or will allow ground disturbance to proceed without a Native American monitor.

CUL-7 The project owner shall grant authority to halt construction to the CRS, alternate CRS and the CRMs in the event previously unknown cultural resource sites or materials are encountered, or if known resources may be impacted in a previously unanticipated manner (discovery). Redirection of ground disturbance shall be accomplished under the direction of the construction supervisor in consultation with the CRS.

In the event cultural resources are found or impacts can be anticipated, the halting or redirection of construction shall remain in effect until all of the following have occurred:

1. The CRS has notified the project owner, and the CPM and Western have been notified within 24 hours of the discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning, including a description of the discovery (or changes in character or attributes), the action taken (i.e. work stoppage or

redirection), a recommendation of eligibility and recommendations for mitigation of any cultural resources discoveries whether or not a determination of significance has been made.

2. The CRS and the project owner have consulted with the CPM and Western, and the CPM and Western have concurred with the recommended eligibility of the discovery and proposed data recovery or other mitigation; and

3. Any necessary data recovery and mitigation has been completed.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM, Western and CRS with a letter confirming that the CRS, alternate CRS and CRMs have the authority to halt construction activities in the vicinity of a cultural resource discovery, and that the project owner shall ensure that the CRS notifies the CPM and Western within 24 hours of a discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning.

Cul-8 The project owner or its agents shall not conduct any activities within the fenced portion of CA-RIV-6370H or remove any portion of the fence without approval of the CPM. Any contract or agreement to purchase any interest in the project (or land identified in the AFC as the project area) must include a clause obligating the successor in interest to the terms of the Memorandum of Agreement between Western and the CA SHPO.

Verification: The project owner shall make a statement in each Monthly Compliance Report during construction and in each Annual Compliance Report during operation regarding the condition of the fence surrounding CA-RIV-6370H, the condition of the site and the project's compliance with this condition.

Cul-9 The project owner shall invite tribal leaders, elders and/or representatives of the Salt River Pima-Maricopa Indian Community, the Fort Yuma Quechan Tribe, the Chemehuevi Indian Tribe and the Fort Mojave Indian Tribe to bless the project area and conduct other appropriate ceremonies. As recommended in "Blythe Energy Projects American Indian Ethnographic Assessment Study, Final Report," participants shall be provided with adequate compensation in the form of a consulting fee and reimbursement for travel, meal and lodging costs, if lodging is necessary. Members of the Tukic-speaking Cahuilla groups, Yuman-speaking Cocopah, Kumeyaay, Pai, and Yavapai tribes, the Twenty-nine Palms Band of Mission Indians (Chemehuevi) and Maricopa members of the Gila River and Ak-Chin Pima-Maricopa Indian Community shall also be notified of the site visit and invited to attend and conduct appropriate ceremonies. The project owner shall also invite Western's Historic Preservation Officer, the CPM and City of Blythe officials to the blessing. The date(s) for the blessing and ceremonies shall be within 30 days of certification or at a time mutually convenient to the tribes, project owner, Western's Historic Preservation Officer, the CPM and the City of Blythe officials.

Verification: Within 30 days of the certification, the project owner shall provide copies of the invitation letters to the CPM. If additional time and correspondence is

required to arrive at a mutually convenient time, copies of all correspondence to finalize the blessing/ceremonies date shall be provided to the CPM. Within 10 days of the blessing ceremony, the project owner shall provide a list of attendees to the CPM.

Cul-10 The project owner shall provide copies to the CPM of documents submitted to Western for compliance with Section 106 of the National Historic Preservation Act. If the project owner becomes a signatory to the Memorandum of Agreement (MOA) for the BEP I project, then correspondence regarding compliance with the stipulations of that agreement shall be provided to the CPM.

Verification: Within 15 days after documents are provided to Western for their compliance with the NHPA, the project owner shall provide copies of the correspondence to the CPM. If the project owner becomes a signatory to the MOA for the BEP I project, correspondence regarding compliance with the stipulation shall be provided in the next Monthly Compliance Report.

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HAZARDOUS MATERIALS MANAGEMENT

Testimony of Alvin J. Greenberg, Ph.D. and Rick Tyler

INTRODUCTION

The purpose of this Hazardous Materials Management analysis is to determine if the proposed Blythe Energy Project Phase II (BEP II) has the potential to cause 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 provide employees with special protective equipment and training to reduce the potential for health impacts associated with the handling of hazardous materials. The **Worker Safety and Fire Protection** section of this document describes the requirements applicable to the protection of workers from such risks.

Aqueous ammonia (19.5 to 30 percent ammonia in aqueous solution) and anhydrous ammonia are the only acutely hazardous material proposed to be used or stored at the BEP II in quantities exceeding the reportable amounts defined in the California Health and Safety Code, section 25532 (j) (BEP II 2003f, Table 7.9-2). Aqueous ammonia would be used for controlling oxides of nitrogen (NO_x) emissions through selective catalytic reduction and for condensate pH control. Anhydrous ammonia will be used in the inlet chilling system.

BEP II has proposed to use anhydrous ammonia as a refrigerant for an inlet chilling system. This system would use approximately 5,400 pounds of anhydrous ammonia circulating in a closed loop system. The use of a closed system would avoid refrigerant exposure to atmospheric conditions and would obviate the need for routine deliveries because losses would be minimal (BEP II 2003f). Anhydrous ammonia is stored as a liquefied gas at elevated pressure and high internal energy that can act as a driving force in an accidental release thus rapidly introducing large quantities of the material to the ambient air and resulting in high down-wind concentrations.

Other hazardous materials, 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 as a result of the quantities on-site, their relative toxicity, their physical state, and/or their environmental mobility. Although no natural gas is stored, the project will also involve the handling of large amounts of natural gas. Natural gas poses some risk of fire. BEP II will tap into the natural gas line constructed for the existing BEP I and therefore would not require the construction of a new gas pipeline (BEP II 2002d Section 2.2.7). This line supplies natural gas from the El Paso Natural Gas Terminal on the Arizona side of the Colorado River.

The BEP II will also require the transportation of aqueous ammonia, and initially 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 (42 USC §9601 et seq.), contains the Emergency Planning and Community Right To Know Act (also known as SARA Title III). The Clean Air Act (CAA) of 1990 (42 USC 7401 et seq. as amended) established a nationwide emergency planning and response program and imposed reporting requirements for businesses which store, handle, or produce significant quantities of extremely hazardous materials. The CAA section on Risk Management Plans (42 USC §112(r)) requires the 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 both SARA Title III and the CAA are reflected in the California Health and Safety Code, section 25531, et seq. Suppliers of hazardous materials must adhere to the U.S. Department of Transportation (DOT) requirements for Hazardous Materials vendors to prepare and implement security plans per 49 CFR 172.800; and ensure that all their hazardous materials drivers are in compliance with personnel background security checks per 49 CFR Part 1572, Subparts A and B.

STATE

The California Health and Safety Code, section 25534, 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 Riverside County Hazardous Materials Division. This Business Plan is required to contain information on the business activity, the owner, a hazardous materials management plan and 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 insure 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 to 515, set forth requirements for design, construction and operation of vessels and equipment used to store and transfer ammonia. These sections generally codify the requirements of several industry codes, including the American Society of Mechanical Engineers (ASME) Pressure Vessel Code, the American National Standards Institute (ANSI) K61.1 and the National Boiler and Pressure Vessel Inspection Code. These codes apply to anhydrous ammonia but are also used to design storage facilities for aqueous ammonia.

California Health and Safety Code, section 41700, requires that "No person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."

LOCAL

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 published in 1997 (Uniform Fire Code, 1997) and includes minimum setback requirements for outdoor storage of ammonia. The administering agency for this authority is the City of Blythe.

The Certified Unified Program Authority (CUPA) with responsibility to review RMPs and Hazardous Materials Business Plans is the Riverside County Hazardous Materials Division.

SETTING

The proposed BEP II would be located on the western portion of a 152-acre parcel of land, which includes the existing BEP I site. This site is located east of the Blythe Airport, approximately 5 miles west of the center of the City of Blythe, bordering Hobsonway on the south and Buck Boulevard on the east. Buck Boulevard was paved as part of the approved BEP, and would be the main access to the site. The site topography is flat, with an elevation of 335 feet above mean sea level. The nearest residence is approximately 2,750 feet southwest of the site. The closest schools are located approximately 4.5 miles east of the proposed BEP II site, in the City of Blythe.

The proposed project will be a combined-cycle electric generating facility consisting of two Siemens Westinghouse V84.3a F-Class combustion turbine generators (CTG), two heat recovery steam generators (HRSG), and a steam turbine generator (STG), along

with accompanying auxiliary systems and equipment. Natural gas-fuel will be supplied by the pipeline constructed as part of the approved BEP I.

Several factors associated with the area in which a project is to be located affect its potential to cause public health impacts from an accidental release of a hazardous material. These include:

- local meteorology;
- terrain characteristics; and
- location of population centers and sensitive receptors relative to the project.

METEOROLOGICAL CONDITIONS

Meteorological conditions, including wind speed, wind direction and air temperature, affect the extent to which accidentally released hazardous materials would be dispersed into the air and the direction in which they would be transported. This affects the potential magnitude and extent of public exposure to such materials, as well as the associated health risks. When wind speeds are low and the atmosphere is 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 (7.7) and Appendix 7.9 of the AFC (BEP II 2002d). Staff agrees with the applicant that use of F stability (stagnated air, very little mixing) and 1.0 meter per second wind speed is appropriate for conducting the Offsite Consequence Analysis. Staff believes these represent a reasonably conservative scenario and thus reflects worst case atmospheric conditions.

TERRAIN CHARACTERISTICS

The location of elevated terrain (terrain above the power plant stack height) is often an important factor to be considered in assessing potential exposure. An emission plume resulting from an accidental release may impact high elevations before impacting lower elevations. The BEP site is approximately 70 feet above and west of the Colorado River Valley and the City of Blythe, and about 60 feet below the elevation and east of the Blythe Airport. Terrain above the stack height (130 feet) within a 10-mile radius exists approximately 4 miles to the east of the proposed site (BEP II 2002d Figure 7.8-1).

LOCATION OF EXPOSED POPULATIONS AND SENSITIVE RECEPTORS

The general population includes many sensitive subgroups that may be at greater risk from exposure to emitted pollutants. These sensitive subgroups include the very young, the elderly, and those with existing illnesses. In addition, the location of the population in the area surrounding a project site may have a large bearing on health risk. Figure 7.9-1 in the AFC (BEP II 2002d) shows the location of sensitive receptors in the project vicinity. The nearest sensitive receptors are approximately 4.5 miles away in the City of Blythe.

IMPACTS AND ANALYSIS

Staff reviewed and assessed the potential for the transportation, handling, and use of hazardous materials to impact the surrounding community. All chemicals and natural gas were evaluated.

METHODOLOGY

In order to assess the potential for released hazardous materials to travel off-site and affect the public, staff analyzed several aspects of the proposed use of these materials at the facility. Staff recognizes that some hazardous materials must be used at power plants. Therefore, staff conducted its analysis by examining the choice and amount of chemicals to be used, the manner in which the applicant will use the chemicals, the manner it will be transported to the facility and transferred to facility storage tanks, and the way the applicant plans to store the materials on-site.

Staff reviewed the applicant's proposed engineering 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, that 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 the public.

Staff reviewed and evaluated the applicant's proposed use of hazardous materials as described by the applicant (BEP II 2003f, AFC Section 7.9). 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 Table 7.9-2 of the Supplement to Revision I of the AFC and determined the need and appropriateness of their use.
- Step 2: Those chemicals, proposed for use in small amounts or whose physical state is such that there is virtually no chance that a spill would migrate off 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 theoretical impacts on the public of a worst-case spill of hazardous materials even with the mitigation measures proposed by the applicant. When mitigation methods proposed by the applicant are sufficient, no further mitigation is recommended. If the proposed mitigation is not sufficient to reduce

the potential for adverse impacts to an insignificant level, staff will propose additional prevention and response controls until the potential for causing harm to the public is reduced to an insignificant level. It is only at this point that staff can recommend that the facility be allowed to use hazardous materials.

PROJECT IMPACTS

Small Quantity Hazardous Materials

In conducting the analysis, staff determined in Steps 1 and 2 that some materials, although present at the proposed facility, pose a minimal potential for off-site impacts as they will be stored in a solid form or in smaller quantities, have low mobility, or have low levels of toxicity. These hazardous materials, which were eliminated from further consideration, are discussed briefly below.

During the construction phase of the project, the only hazardous materials proposed for use include paint, paint thinner, cleaners, solvents, sealants, gasoline, diesel fuel, motor oil, hydraulic fluid, lubricants, welding flux and compressed gases. In addition to these materials, hydroxyacetic acid (approximately 1,000 pounds) and formic acid (approximately 600 pounds) will be used by a contractor to clean the Heat Recovery Steam Generators feedwater system prior to start up. Additionally, the applicant has indicated that the HRSG cleaning contractor may use an alternative compound – an EDTA-based system - instead of hydroxyacetic acid and formic acid. EDTA, which is usually in the form of a sodium or calcium salt, is a solid material dissolved in water and while toxic if ingested in large amounts, does not present a risk of off-site impacts due to almost no volatility. Any impact of spills or other releases of any of these three materials will be limited to the site due to the small quantities involved, the infrequent use and hence reduced chances of release, and/or the temporary containment berms used by contractors. Petroleum hydrocarbon-based motor fuels, mineral oil, lube oil, and diesel fuel are all of very low volatility and represent limited off-site hazard even in larger quantities.

During operations, acutely hazardous chemicals such as cyclohexylamine, morpholine, ethanolamine, methoxypropylamine, and other various chemicals (see Appendix C of this document for a list of all chemicals proposed to be used and stored at BEP II), would be used and stored in relatively small amounts and represent limited off-site hazard due to their small quantities, low volatility, and/or low toxicity.

After removing from consideration those chemicals that pose no risk of off-site impact in Steps 1 and 2, staff continued with Steps 3, 4, and 5 to review the remaining hazardous materials: sodium hypochlorite, sodium hydroxide, hydrochloric acid, sulfuric acid, natural gas, aqueous ammonia, anhydrous ammonia, and R-123.

Large Quantity Hazardous Materials

Sodium hypochlorite, sodium hydroxide, and sulfuric acid will be stored on-site but do not pose a risk of off-site impacts because they have relatively low vapor pressures and thus spills would be confined to the site. Because of 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 due to the extremely low volatility of this aqueous solution of sulfuric acid. However, in order to protect against risk of fire, staff proposes Condition of Certification **HAZ-5** which will require that no combustible or flammable material is stored within 50 feet of the sulfuric acid tank.

Anhydrous Ammonia

Anhydrous ammonia is proposed to be used by the Applicant as a refrigerant in the inlet air chiller system. 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 in the closed loop cooling system. Anhydrous ammonia is a gas at ambient temperature but in many parts of the refrigerating system would exist as a liquid under high pressure. The rupture of a pipe or valve in the chilling system would likely result in a release of a mixture of ammonia vapor and very fine liquid droplets. The result of such a release would be a denser-than-air mixture that would create a vapor cloud. If a release occurred in other parts of the refrigerating system where ammonia is in the pure vapor phase, the ammonia would be less dense than air, would release at a faster rate, and would not form a vapor cloud.

The anhydrous ammonia will be kept in a closed loop system that will have no contact with the outside atmosphere. More importantly, the applicant is proposing to use an indirect anhydrous ammonia chiller system that uses only about 15% of the normal volume of anhydrous ammonia such as that currently used at the BEP I power plant. This significantly lower volume reduces the risk of using this acutely hazardous material. Piping of the chilling system will be welded construction with minimal flanged connections to minimize the potential for spills. Safety controls such as ammonia detection equipment, alarms and an automatic shutdown system would be installed in the equipment enclosures. Additionally, an automatic fire suppression system would be installed to minimize the chances that a fire may cause an accidental release from the system (BEP II 2003f Page 7.9-29). The refrigeration system would not require routine deliveries of anhydrous ammonia, but may require small quantities from time to time to keep the system charged (BEP 2003a, Page 78). According to the applicant, this occasional recharge would require only approximately 300 pounds of additional refrigerant every four to five years, delivered by tanker truck with varying degrees of load as part of routine deliveries to other recipients (Gavahan 2003). Additionally, it may be necessary to drain and recharge the entire system during the life of the plant.

The Supplement to Revision 1 of the AFC (BEP 2003b, section 7.9) discusses 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 at the location of the high pressure receiver where all 5400 pounds could be emitted. The rate of release through an assumed hole of inch in diameter was calculated using the Bernoulli's Formula to be 3.13 kg/sec and 1.74 kg/sec for the high and low pressure of the system respectively. The U.S. EPA DEGADIS air dispersion model was used to estimate airborne concentrations of ammonia. Two atmospheric conditions were used to model the worst-case scenario under high and low pressure: stability class F with wind speed of 1 m/s, and stability class D with wind speed of 3 m/s.

The results of the low pressure modeling (60 psig) with stability class F predicted concentration of 100 ppm at 2.4 miles from the source. Concentrations of greater than 1000 ppm were predicted out to a distance of 0.3 miles from the source. For stability class D this scenario predicted concentrations greater than 1000 ppm out to 0.1 mile from the source, and 100 ppm at 0.53 miles. The results of the high pressure modeling (195 psig) with stability class F predicted concentration of 100 ppm at 2.9 miles from the source, and concentrations greater than 1000 out to 0.2 miles. For stability class D this scenario predicted concentrations greater than 1000 ppm out to 0.11 miles from the source, and 100 ppm at 0.66 miles from the facility.

According to the AFC, the nearest residence to the BEP II facility is approximately 0.75 miles southwest. The community of Mesa Verde (Nicholls Warm Springs) is about 2.2 miles southwest of the anhydrous ammonia refrigerating system. About 5 to 6 isolated residences are also located on the elevated Palo Verde Mesa near the BEP II site (BEP II 2003f Page 7.9-26). According to the modeling results for worst-case scenario with stability class F, the nearest residence may experience ammonia concentrations slightly over 400 ppm while the surrounding population could be impacted by concentrations greater than 100 ppm. With stability class D, an ammonia concentration of approximately 100 ppm is estimated to occur at the nearest residence.

To assess the potential impacts associated with an accidental release of either anhydrous or aqueous ammonia, staff typically evaluates where four “bench mark” exposure levels of ammonia gas occur off-site. These include:

1. the lowest concentration posing a risk of lethality, 2,000 ppm;
2. the Immediately Dangerous to Life and Health (IDLH) level of 300 ppm;
3. the Emergency Response Planning Guideline Level 2 (ERPG-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: 75 ppm.

Because members of the off-site public would be exposed to airborne concentrations considerably in excess of staff’s 75 ppm, and some off-site public would even experience airborne concentrations in excess of the ERPG-2 and the IDLH level, staff found it necessary to conduct further review and evaluation of this option for the inlet chiller. To do this, staff reviewed the accident frequency for releases from ammonia refrigeration units. This review also included an assessment staff conducted for the BEP I facility as found in the Final Staff Assessment for that project. For that project, staff had requested that the applicant provide an analysis of the potential for a release of anhydrous ammonia from the refrigeration unit. The applicant provided results which indicated a probability of accidental release ranging between 7.2 in 10,000 and 3.6 in 100,000 plant years of operation. Further evaluation by staff indicated that historically serious releases involving refrigeration plants occur at a frequency of about 1 in 100,000 per plant year of operation (Baldcock, 1980) and that more recently, both serious and non-serious accidental releases from ammonia refrigeration systems have occurred at an even greater frequency in certain parts of the country (EPA 1998).

Staff also evaluated the potential for impacts on three specific receptor locations including Mesa Verde, the Blythe Airport and on Interstate 10. The modeling results indicate that significant impacts would occur at Mesa Verde, about 2 miles from the project, with winds from the east and north east direction with E or F stability. Staff's analysis indicates that winds in the direction of Mesa Verde with E or F stability occur with a frequency of about 0.021 (about two percent of the time)(BEP, 1999a). Thus, significant impacts on Mesa Verde would have a probability of occurrence of about 2 in 10,000,000 per year. Staff's analysis of the Blythe Airport, about 1.5 miles from the project, indicates the probability of impact with winds from the south east and with D, E and F stability. These meteorological conditions occur with a frequency of about 0.011 (about one percent of the time). Thus, the risk of significant impact at the Blythe Airport is about 1 in 10,000,000. The modeling results indicate that impacts on Interstate 10, about 0.25 miles from the project, could be associated with winds from the north, north by north east, north east, east by north east, west by north west, north west and north by north west with D, E or F stability. These meteorological conditions occur with a frequency of about 0.203 (about 20 percent of the time). Thus, the risk of significant impact on Interstate 10 is about 2 in 1,000,000. In general, staff considers a risk above 1 in 1,000,000 per year significant with the potential of more than 100 serious injuries and or fatalities. Staff could not quantify the potential number of injuries or fatalities that could result from a release affecting Interstate 10. However, staff does believe that such an event has the potential to cause more than 100 injuries and or fatalities on Interstate 10. While this level of risk cannot be considered insignificant, it is close to an insignificant level of risk. It is typical regulatory practice in such cases to impose mitigation to reduce risk to the lowest level that is reasonably practical.

After review of the accident release data and frequency of occurrence at ammonia refrigeration units, staff has concluded that the accident release frequency and the resultant impacts can be significant. Indeed, the U.S. EPA issued a Safety Alert on Ammonia Used as a Refrigerant in 1998 (EPA 1998) and published a Chemical Safety Alert on ammonia releases from refrigeration facilities in 2001 (EPA 2001). This document also recommends the adoption and implementation of a hazard reduction plan at facilities that use anhydrous ammonia for refrigeration. Staff also investigated the leak of anhydrous ammonia at the BEP I power plant in September 2004. Staff found that the scrubber on the containment building did work but that due to a lack of monitoring capability, power plant personnel were unaware of the efficiency of the scrubber and therefore properly implemented the Emergency Response Plan. Staff has made several recommendations regarding preventing this type of accidental release and resulting disruption of traffic on I-10 from occurring again and will reiterate those recommendations for the BEP II power plant in proposed Condition of Certifications **HAZ-8** and **HAZ-11**.

Staff has also investigated the use of alternative chemicals for use as inlet chillers. One promising alternative currently in use in the United States and Europe is an aqueous lithium bromide absorption chiller. An aqueous solution of lithium bromide is much less toxic and an accidental release would not result in off-site consequences. Staff is asking the applicant to seriously consider this alternative method but due to staff's awareness that the manufacturer of the combustion turbine may not provide a product warranty if a different chiller system is used, staff is not requiring that this alternative be

used. Staff is requiring in proposed condition of certification (COC) **HAZ-12** that this system be evaluated and the results reported to the Energy Commission.

Staff finds that although the chances of accidental release from the proposed BEP II would be small, the impacts of such a release could be quite significant. Therefore, in order to reduce this risk to a level of insignificance, staff proposes Condition of Certification (**HAZ-8**) which would require the Applicant to prepare and implement an Ammonia Refrigeration Hazard Reduction Plan consistent with U.S. EPA guidelines (EPA 2001). Additionally, technical organizations such as the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE), the International Institute of Ammonia Refrigeration (IIAR), and the American National Standards Institute (ANSI), have established codes, standards, and guidelines for the safe use of anhydrous ammonia as a refrigerant. The proposed refrigeration plant will also be subject to regulations requiring participation in the State Risk Management Program (RMP) and Process Safety Management (PSM) program post certification. It is staff's opinion that participation in these programs will result in development and implementation of extensive administrative controls designed to improve the safety of the plant. Staff is also proposing the use of an automatic fire suppression system similar to that required for the BEP I project. Requiring the use of an automatic fire suppression system is supported by the record of past releases from refrigeration plants that suggests a significant causal relationship between fires and accidental releases from such plants. Staff is proposing a condition of certification (**HAZ-10**) requiring installation of an automatic fire suppression system on the refrigeration plant. Staff is also proposing a condition of certification (**HAZ-11**) requiring that certain ammonia monitors and automatic door closures be installed in the anhydrous ammonia containment building and vent scrubber.

Based on the analysis above, staff concludes that the risk associated with the proposed use of anhydrous ammonia as refrigerant are below significant levels if the mitigation measures described above are required.

Aqueous Ammonia

Aqueous ammonia will be used in controlling the emission of oxides of nitrogen (NO_x) from the combustion of natural gas in the facility. The accidental release of aqueous ammonia without proper mitigation can result in very high down-wind concentrations of ammonia gas. Two storage tanks will be used to store the 19 to 30 percent aqueous ammonia with a maximum capacity of 10,000 gallons each.

The use of aqueous ammonia can result in the formation and release of toxic gases in the event of a spill even without interaction with other chemicals. This is a result of its moderate vapor pressure and the large amounts of aqueous ammonia that will be used and stored on-site. However, as with sodium hypochlorite solution, the use of aqueous ammonia instead of the much more hazardous anhydrous ammonia (i.e. ammonia that is not diluted with water) poses far less risk.

To assess the potential impacts associated with an accidental release of aqueous ammonia, staff uses the four "bench mark" exposure levels of ammonia gas described above for anhydrous ammonia. (A detailed discussion of the exposure criteria

considered by staff and their applicability to different populations and exposure-specific conditions is provided in Appendix A of this analysis.) If the potential exposure associated with a potential release exceeds 75 ppm at any public receptor, staff presumes that the potential release poses a risk of significant impact. However, staff also assesses the probability of occurrence of the release and/or the nature of the potentially exposed population in determining whether the likelihood and extent of potential exposure is sufficient to support a finding of potentially significant impact.

Section 7.9.2.2.1 of the AFC (BEP II 2002d) describes the modeling parameters used for the worst case accidental releases of aqueous ammonia in the applicant's Off-site Consequence Analysis (OCA). According to the applicant, the worst-case release is associated with a failure of one of the storage tanks in the containment area, and the second scenario is associated with a spill from a delivery tanker truck during loading operation. The ALOHA program air dispersion model was used for modeling the aqueous ammonia releases. The ALOHA program cannot directly model solutions (like ammonia in water), and assumes that the entire content of an aqueous ammonia release is anhydrous ammonia. Therefore the ALOHA program would significantly over predict the threat zone of an aqueous ammonia release.

The worst-case storage tank spill (scenario #1) assumed a release of aqueous ammonia in a rate of 0.127 kg/s, winds of 1.0 meter per second, ambient temperature of 100°F, and category F stability. The second storage tank spill (scenario #2) used stability class D, a wind speed of 5.0 m/s, and ambient temperature of 100°F. The ammonia delivery truck spill (scenario #3) assumed the tanker would contain 5,000 gallons of aqueous ammonia, the release would last only three to five minutes before being controlled, would be totally contained in a diked area around the loading area, and that the meteorological conditions were winds of 1.0 m/s, ambient temperature of 100°F, and stability class F (BEP II 2002d, AFC Page 7.9-19). The spill rate was calculated to be 3.17 kg/s using the NOAA methodology. The final delivery truck spill (scenario #4) assumed winds of 5.0 m/s, ambient temperature of 100°F, and stability class D.

The results of the applicant's modeling showed that off-site airborne concentrations of ammonia would exceed the level staff uses to establish insignificance (75 ppm) out to a distance of 0.86 miles from the ammonia storage tank for the tank spill scenario modeled with F stability. The maximum concentration at the nearest site boundary (Hobsonway- approximately 0.15 miles or 800 feet south from the tank according to the AFC) was calculated to be approximately 2,000 ppm. For the tank spill scenario modeled with stability class D, results showed a concentration of 75 ppm at 0.24 miles from the ammonia storage tank and approximately 200 ppm at the nearest site boundary (BEP II 2002d, AFC Pages 7.9-18 and 7.9-19 and Figures 7.9-2 and 7.9-3).

For the second scenario involving a spill from a delivery truck, the applicant's modeling using stability class F showed a concentration of 75 ppm at 6.0 miles away from the truck unloading area. Over 2,000 ppm was calculated at the nearest site boundary. The modeling using stability class D showed a concentration of 75 ppm at 1.7 miles, and over 2,000 ppm at the nearest site boundary (BEP II 2002d, AFC Page 7.9-19 and Figures 7.9-4 and 7.9-5).

Staff has reviewed this Off-site Consequence Analysis and found the results to be indicative of significant off-site impacts. Because the applicant used an air dispersion model which significantly over-predicts downwind airborne concentrations, staff conducted SCREEN 3 modeling for two different scenarios associated with a failure of the aqueous ammonia storage tank. Staff assessed the potential for impact from a spill into the secondary containment depicted in Figure 2.0-4 of the AFC. Staff estimated the surface area of the containment area at 1,144 square feet. The applicant is not proposing to install a subsurface sump under the storage tank or under the tanker truck transfer area. Staff evaluated the airborne dispersion of ammonia vapors if the spill occurred at temperatures of 120°F. The US EPA SCREEN3 model was run for rural terrain, and for atmospheric stability class F with a wind speed of 1.0 m/s and for atmospheric stability class D with a wind speed of 5 m/s. Staff also recalculated the distances from the aqueous ammonia storage tank to the nearest fenceline (695 feet) and the nearest residence (3628 feet) using AFC Figures 2.0-4 and 7.9-6. Staff also modeled a spill during transfer from a tanker truck to the storage tank using the same two meteorological scenarios and a spill area of 266 square feet.

The results of staff's modeling show that if an accidental release of aqueous ammonia from the storage tank occurs, airborne concentrations of ammonia are predicted to be 2,558 ppm at the fenceline and 170 ppm at the nearest residence for the worst-case spill (F stability with 1 m/s wind speed). For the other more likely meteorological scenario (D stability with 5 m/s wind speed), the airborne concentrations of ammonia are predicted to be 447 ppm at the fenceline and 26 ppm at the nearest residence. Staff's modeling also found that for a transfer spill, the airborne concentration of ammonia is predicted to be 1,565 at the fenceline and 105 ppm at the nearest residence for the worst-case spill (F stability with 1 m/s wind speed) and 275 ppm at the fenceline and 16 ppm at the nearest residence (D stability with 5 m/s wind speed). The predicted levels of 26 ppm and 16 ppm at the nearest residence for the more likely meteorological scenario do not represent a significant risk to the public.

Therefore, given the results of staff's offsite consequence analysis, the finding that worst-case meteorological conditions are unlikely to occur with any significant frequency, the finding that the sparsely populated area would be very easy to evacuate should a release of aqueous ammonia occur, staff concludes that the use, storage and handling of aqueous ammonia will not cause a significant impact. This conclusion is further supported by the finding that the engineering controls proposed to be implemented by the applicant and those required by staff for the storage and transfer of aqueous ammonia are adequate and appropriate.

Hydrochloric Acid

Hydrochloric acid (HCl) may be used initially for cleaning of the HRSGs, and then once every 3-5 years (unless an EDTA-based system is used). Due to previous concerns expressed by the Energy Commission staff, modeling for an accidental release of hydrochloric acid was performed by the applicant. Two scenarios were assessed for an uncontrolled release from a tank: the worst-case scenario assumed wind speed of 1.0 m/s, ambient temperature of 100°F, and stability class F; and the second scenario assumed wind speed of 5.0 m/s, ambient temperature of 100°F, and stability class D. Both scenarios assumed a loss of 10,000 pounds of hydrochloric acid, the worst case

with a rate of 1.82 kg/s and the second with a rate of 6.35 kg/s as calculated with the NOAA methodology. A surface area of approximately 3,283 square feet and 1 centimeter deep was assumed. The results of the worst-case scenario predicted an airborne concentration of HCl of 50 ppm at 1.5 miles from the HRSGs, and a concentration of approximately 2,000 ppm at the site boundary, and in the range of 250 ppm at the nearest residence. The second scenario modeled predicted a concentration of 50 ppm at 1.2 miles, a concentration of over 2,000 ppm at the site boundary, and approximately 200 ppm at the nearest residence. According to the AFC, the nearest residence to the release point is approximately 0.52 miles southwest (BEP II 2002d, Page 7.9-25).

To assess the potential impacts associated with an accidental release of either anhydrous or aqueous ammonia, staff uses three "bench mark" exposure levels of hydrogen chloride gas. These include:

1. The IDLH level of 50 ppm.
2. The public Emergency Exposure Guidance Level (EEGL) of 20 ppm, developed by the National Research Council for short-term public exposures, and is protective against severe effects.
3. The Cal-EPA 1-hour acute Reference Exposure Level (acute REL) of 1.4 ppm developed by the Office of Environmental Health Hazard Assessment to protect against mild irritative effects on the respiratory system.

Staff considers the NRC EEGL of 20 ppm to be the most useful bench mark in determining the potential for significant risk.

Staff has reviewed the applicant's modeling of an accidental release of hydrochloric acid and determined that all off-site airborne levels predicted by the applicant's modeling under both meteorological scenarios are considerably in excess of all three bench mark levels used by staff to assess impacts to public health. Thus, were staff to accept these modeling results, staff would find that a significant risk of adverse health effects would likely occur with a spill of HCl. However, staff conducted its own modeling using the U.S. EPA SCREEN3 air dispersion model. Staff has traditionally used SCREEN3 to predict the worst-case ground level concentrations and impacts due to hazardous materials releases. Although it tends to over-estimate these levels, it does so to a lesser degree than the ALOHA model which has difficulty assessing the emissions of gases from an aqueous solution.

Staff assumed that 30% HCl in water would be used (this is consistent with other power plant projects) and that an accidental spill would result in a pool with a surface area of 3,283 square feet. (The spill was assumed to be limited to a reasonable size by taking into consideration an assumed location of the temporary HCl storage tank on-site, the slope of the area towards drains or berms, and immediate containment efforts.) Staff found that under F stability with 1 m/s wind speed, the airborne concentration predicted to occur at the fenceline (assumed to be 695 feet from the location of the temporary storage tank based on a review of AFC Figure 2.0-4) would be 1,065 ppm and 81 ppm at the nearest residence (approximately 3,628 feet away). This compares to the

applicant's modeling which predicts 2,000 ppm at the fenceline and approximately 500 ppm at the nearest residence. Staff also found that under D stability with 5 m/s wind speed, the airborne concentration predicted to occur at the fenceline would be 206 ppm and 12 ppm at the nearest residence. This compares to the applicant's modeling which predicts 2,000 ppm at the fenceline and approximately 250 ppm at the nearest residence.

The airborne concentrations predicted by staff's modeling for the worst-case meteorological conditions are in excess of the EEGL of 20 ppm. Staff also found that for more likely meteorological conditions of D stability and winds of 5 m/s, the predicted airborne concentration of HCl at the nearest residence (12 ppm) would be below the EEGL. Furthermore, per staff's usual method of analysis, staff has determined that because HCl would be used only temporarily, infrequently, and not stored on-site continuously, staff finds that the risk of an accident resulting in a spill during worst-case meteorological conditions to be a very remote and insignificant probability. Nevertheless, the airborne concentrations both on and off-site are significant and must be mitigated. Therefore, staff proposes Condition of Certification **HAZ-9** which would require the use of temporary containment berm(s) to limit the size of a spill of any HCl used to clean the HRSG to no more than 500 square feet, a spill size that dispersion modeling predicts would result in airborne concentrations of HCl below the EEGL of 12 ppm at the nearest residence under both meteorological scenarios. This would apply only to the undiluted acid and not the diluted HCl after adding to the water within the HRSGs and water/steam system piping. If this condition is required, staff concludes that the engineering controls proposed to be implemented by the applicant, along with those required by staff, for the storage and transfer of hydrochloric acid, will ensure that any accidental release of hydrochloric acid used for the project will not cause a significant impact.

Natural Gas

Natural gas poses a fire and/or possible explosion risk as a result of its flammability. Natural gas is composed mostly of methane, but also contains ethane, propane, nitrogen, butane, isobutene, and isopentane. It is colorless, odorless, and tasteless and is lighter than air. Natural gas at ninety percent methane can cause asphyxiation. 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 possible explosion if a release were to occur under certain specific conditions. However, it should be noted that, due to its tendency to disperse rapidly (Lees 1998), natural gas is less likely to cause explosions than many other fuel gases, such as propane or liquefied petroleum gas.

While natural gas will be used in significant quantities, it will not be stored on-site. The risk of a fire and/or explosion on-site can be reduced to insignificant levels through adherence to applicable codes and development and implementation of effective safety management practices. In particular, gas explosions can occur in the heat recovery steam generator (HRSG) and during turbine start-up intervals. 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 would 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 would address the handling and use of natural gas and significantly reduce the potential for equipment failure due to improper maintenance or human error.

Since the proposed facility would tap into the gas line constructed as part of the existing BEP I, and will not require the construction of a new gas pipeline off-site, impacts from gas pipelines are not evaluated in this document.

Cooling System Materials

BEP II is proposing to use a wet cooling system with makeup water taken from the raw water storage system. Raw water will be pumped from on-site wells and treated with sodium hypochlorite, sulfuric acid, calcium chloride, an antiscalant, and sodium hydroxide at an on-site treatment plant. The circulating water in the cooling system would be conditioned to minimize corrosion and control for the formation of mineral scale and biofouling. Chemicals added for these purposes will include sulfuric acid, an organic phosphate solution, and a biocide such as sodium hypochlorite (BEP II 2002d, Section 2.2.8.5). Any risks associated with chemical usage in cooling water would be adequately mitigated through compliance with the appropriate federal, state, and local requirements for hazardous materials use, and compliance with staff's proposed conditions of certification.

Transportation of Hazardous Materials

Hazardous materials, including aqueous ammonia, sulfuric acid, and cleaning chemicals, will be transported to the facility via tanker truck. While many types of hazardous materials will be transported to the site, staff believes that transport of aqueous ammonia poses the predominant risk associated with hazardous materials transport due its volatility and frequency of delivery. Anhydrous ammonia will be used as the refrigerant and it will be necessary to transport this hazardous material to the site for initial charging of the refrigeration system, again every four to five years to recharge the system after small losses, and possibly once more to drain and completely refill the system. Although only a very small amount of anhydrous ammonia would be used at BEP II to recharge the system (~300 pounds) every 4 - 5 years, the tanker truck transporting the ammonia to BEP II would be just one of several deliveries to other locations and thus the tanker truck could contain varying amounts of anhydrous ammonia up to the tanker volume of 30,000 pounds.

During the initial charge and the possible drain and recharge, a tanker loaded with approximately 5400 pounds would be required. Thus, during the 30-year life of the project, a total of nine (9) deliveries of anhydrous ammonia could occur. Staff has previously found in other siting cases that this small number of trips would present an insignificant risk of accidental release to the public. Furthermore, the same on-site precautions and training for the use of anhydrous ammonia in the refrigeration system and the same off-site emergency response capabilities would be more than adequate to address and respond to any accidental release from these occasional tanker truck deliveries. Staff therefore finds that the transport of anhydrous ammonia to the facility

for use as a refrigerant would present an insignificant risk, certainly much less than that presented and assessed for the multiple deliveries of aqueous ammonia.

Staff reviewed the Applicant's proposed transportation routes for hazardous materials delivery (BEP II 2002d, AFC Section 7.4.2.2). Ammonia can be released during a transportation accident and the extent of impact in the event of such a release would depend on the location of the accident and on the rate of dispersion of ammonia vapor from the surface of the aqueous ammonia pool. The likelihood of an accidental release during transport is dependent on three factors:

- the skill of the tanker truck driver,
- the type of vehicle used for transport, and
- accident rates.

To address this concern, staff evaluated the risk of an accidental transportation release in the project area. Staff's analysis focused on the project area after the delivery vehicle leaves the main highway (I-10, US-95 or SR-78). 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 USC §5101 et seq, The US Department of Transportation Regulations 49 CFR Subpart H, §172-700, and California DMV Regulations on Hazardous Cargo). These regulations also address the issue of driver competence. See AFC section 7.4 for additional information on regulations governing the transportation of hazardous materials.

To address the issue of tank truck safety, aqueous ammonia will be delivered to the proposed facility in Department of Transportation (DOT) certified vehicles with design capacity of 6,000 gallons. These vehicles will be designed to DOT Code MC-307. These are high integrity vehicles designed for hauling of caustic materials such as ammonia. Staff has, therefore, proposed Condition of Certification **HAZ-8** to ensure that regardless of which vendor supplies the aqueous or anhydrous ammonia, delivery will be made in a tanker which meets or exceeds the specifications described by these regulations.

To address the issue of accident rates, staff reviewed the technical and scientific literature on hazardous materials transportation (including tanker trucks) accident rates in the United States and California. Staff relied on six references and three federal government databases to assess the risks of a hazardous materials transportation accident.

Staff used the data from the Davies and Lees (1992) article which references the 1990 Harwood et al. study, to determine that the frequency of release for transportation of hazardous materials in the U.S. is between 0.06 and 0.19 releases per million miles traveled on well designed roads and highways. The maximum usage of aqueous ammonia each year of operation of the proposed BEP II will require about 9 tanker truck deliveries of aqueous ammonia per month (approximately 108 per year) each delivering about 5,000 gallons. Each delivery will travel approximately 2.5 miles between I-10 and the facility per delivery along Neighbors Boulevard. to Hobsonway to Buck Boulevard. to

the facility (the shortest and most direct way). The result is about 270 miles of delivery tanker truck travel in the project area per year. Staff finds that the risk over this distance is insignificant. Data from the U.S. DOT show that the actual risk of a fatality over the past five years from all modes of hazardous material transportation (rail, air, boat, and truck) is approximately 0.1 in one million.

Staff therefore believes the risk of exposure to significant concentrations of aqueous ammonia during transportation to the facility is insignificant because of the remote possibility of accidental release of a sufficient quantity to present a danger to the public. The transportation of similar volumes of hazardous materials on the nation's highways is not unique nor an infrequent occurrence. Staff's analysis of the transportation of aqueous ammonia to the proposed facility (along with data from the U.S. DOT) demonstrates that the risk of accident and exposure is less than significant.

Based on the environmental mobility, toxicity, quantities present at the site and frequency of delivery, it is staff's opinion that aqueous ammonia poses the predominate risk associated with hazardous materials transportation and use at the proposed facility. Based on this, staff concludes that the risk associated with transportation of other hazardous materials to the proposed facility does not significantly increase the risk of impact beyond that associated with ammonia transportation.

Seismic Issues

The possibility exists that an earthquake would cause the failure of a hazardous materials storage tank. The quake could also cause the failure of the secondary containment system (berms and dikes) as well as electrically controlled valves and pumps. 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, in January 1995, heighten the concern regarding earthquake safety.

Information obtained after the January 1994 Northridge earthquake showed that some damage was caused to several large storage tanks and smaller tanks associated with the water treatment system of a cogeneration facility. Those tanks with the greatest damage, including seam leakage, were older tanks, while the newer tanks sustained displacements and failures of attached lines. Therefore, staff conducted an analysis of the codes and standards, that should be followed in adequately designing and building storage tanks and containment areas to withstand a large earthquake. The proposed facility would be designed and constructed to the applicable standards of the Universal Building Code (UBC) and the California Building Code (CBC) for Seismic Zone 3 (BEP II 2002d Page 7.9-2).

CUMULATIVE IMPACTS

Staff reviewed the potential for the operation of the BEP II combined with existing facilities to result in cumulative impacts on the population within the area. The facility that has the most potential to contribute to cumulative impacts is the existing BEP I facility located adjacent to the proposed project site with about 1,600 feet separating the proposed BEP II ammonia storage area from the existing BEP I ammonia storage area.

In the event of an accidental release of ammonia from both facilities at the same time, cumulative impacts would represent a higher concentration of ammonia in areas where the cloud of gas would overlap and an increase in the impacted zone. However, staff finds that it is unlikely that an accidental release that has very low probability of occurrence (about one in one million per year) would independently occur at the BEP II site and BEP I at the same time. However, the Fire Service Needs Assessment (Hunt Research 2004) pointed out the need for additional HazMat response equipment, training, and personnel. Staff agrees with this needs assessment. Staff also finds that the facility, as proposed by the applicant and with the additional mitigation measures proposed by staff, poses a minimal risk of accidental release that could result in off-site impacts. Therefore, staff concludes that the facility would not contribute to a significant cumulative impact.

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. 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 curbs, berms, and/or catchment basins surrounding each of 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;
- construction of a diked containment area surrounding the truck unloading area; and
- process protective systems including continuous tank level monitors, temperature and pressure monitors, alarms, check valves, emergency block valves, and double-walled piping when needed.

ADMINISTRATIVE CONTROLS

Administrative controls also help to prevent accidents and releases (spills) from moving off-site and impacting the community by establishing worker training programs, process safety management programs and by complying with all applicable health and safety laws, ordinances and standards.

A worker health and safety program will be prepared by the applicant and will include (but is not limited to) the following elements:

- worker training regarding chemical hazards, health and safety issues, and hazard communication;
- procedures to ensure the proper use of personal protective equipment;
- safety operating procedures for operation and maintenance of systems utilizing hazardous materials;
- fire safety and prevention; and
- emergency response actions including facility evacuation, hazardous material spill cleanup, and fire prevention.

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 official will oversee the health and safety program and will have the authority to halt any action or modify any work practice in order to protect the workers, facility, and the surrounding community in the event that the health and safety program is violated.

ON-SITE SPILL RESPONSE

In order to address the issue of spill response, the facility will prepare and implement an Emergency Response Plan which includes information on: hazardous materials contingency and emergency response procedures, spill containment and prevention systems, personnel training, spill notification, on-site spill containment, prevention equipment and capabilities, etc. Emergency procedures will be established which include evacuation, spill cleanup, hazard prevention, and emergency response.

The City of Blythe Fire Department (BFD) fire station located at 201 North Commercial Street approximately 5 miles away is considered first responder for HazMat incidents, with backup service provided by the Riverside County Fire Department (RCFD) Stations 43 and 45. BFD has a response time of 10 minutes (HRC 2000). Currently, the BFD fire station and RCFD Stations 43 and 45 do not have any trained HazMat technicians. Additional response would be provided by the Riverside County HazMat Response Team located in Beaumont, approximately two hours away and manned with 4 HazMat technicians (BEP II 2002d Page 7.6-8, HRC 2000, and RCFD 2003b).

The needs assessment conducted for BEP I and the one conducted for BEP II both indicated that the present HazMat resources will not result in timely response to spills. The needs assessments concluded that “the power plant must build-in all feasible mitigations to reduce the hazardous materials threat, and must provide for the response of trained, private hazardous materials clean-up companies from Los Angeles or Phoenix, to clean up hazardous waste after a release (HRC 2000).” According to the City of Blythe Fire Department (BFD 2003), the mitigation measure chosen by BEP I was to train all personnel at BEP I to the level of Hazmat Technicians, which are capable of complete HazMat response including extraction. The BFD also suggested that BEP II should either pay the BFD and RCFD for training to bring their staff up to the level of Hazmat Technicians, or train their own staff as they did at BEP I (BFD 2003).

Staff understands that the applicant for BEP II has agreed to fund additional resources and training for the BFD and the RCFD to reduce the response time to an adequate one and reduce the potential impacts from a HazMat incident to insignificant.

STAFF'S PROPOSED MITIGATION

Staff proposes eight Conditions of Certification mentioned throughout the text (above) and listed below. **HAZ-1** ensures that no hazardous material would be used at the facility except those listed in the AFC unless there is prior approval by the County and the California Energy Commission Compliance Project Manager (CPM). **HAZ-2** requires that a Risk Management Plan (RMP) be prepared and submitted prior to the delivery of aqueous or anhydrous ammonia.

Staff believes that an accidental release of aqueous ammonia during transfer from the delivery tanker to the storage tank is the most probable accident scenario, and therefore proposes a condition (**HAZ-3**) requiring development of a safety management plan for the delivery of aqueous ammonia. The development of a Safety Management Plan addressing delivery of ammonia will further reduce the risk of any accidental release not addressed by the proposed spill prevention mitigation measures and the required RMP. **HAZ-4** requires that the aqueous ammonia storage tank be designed to certain rigid specifications, **HAZ-5** addresses the storage of sulfuric acid, the transportation of hazardous materials is addressed in **HAZ-6,** & **7**, and **HAZ-8** addresses the use of anhydrous ammonia as a refrigerant for the inlet chiller. **HAZ-9** will reduce the impacts of HCl, should it be used during HRSG cleaning, to an insignificant level. **HAZ-10** will address fire suppression in the anhydrous ammonia refrigeration plant and **HAZ-11** will address anhydrous ammonia leaks by requiring certain sensors and automatic door closures. **HAZ-12** will require that the project owner investigate and consider the use of an aqueous solution of lithium bromide as a refrigerant in the inlet air chiller system and report to the Energy Commission the results of its consideration.

SITE SECURITY

This facility proposes to use hazardous materials that have been identified by the US EPA as materials where special site security measures should be developed and implemented to ensure that unauthorized access is prevented. The EPA published a Chemical Accident Prevention Alert regarding Site Security (EPA 2000a), the US Department of Justice published a special report on Chemical Facility Vulnerability Assessment Methodology (US DOJ 2002), the North American Electric Reliability Council published Security Guidelines for the Electricity Sector in 2002 (NAERC 2002), and the U.S. Department of Energy published a draft Vulnerability Assessment Methodology for Electric Power Infrastructure in 2002 (DOE 2002). In order to ensure that this facility or a shipment of hazardous material is not the target of unauthorized access, staff's proposed General Condition of Certification on Construction and Operations Security Plan **COM-8** (see the **GENERAL CONDITIONS** section of this FSA) will require the preparation of a Vulnerability Assessment and the implementation of Site Security measures consistent with the above-referenced documents and Energy Commission guidelines.

The level of security needed for this power plant is dependent upon the threat imposed, the likelihood of an adversary attack, the likelihood of adversary success in causing a catastrophic event, and the severity of consequences of that event. In order to determine the level of security, the Energy Commission staff will provide guidance in the form of a vulnerability assessment (VA) decision matrix modeled after the U.S. Department of Justice Chemical Vulnerability Assessment Methodology (July 2002) and the U.S. Department of Energy VAM-CF model (DOE 2003). Basic site security measures shall be required at all locations in order to protect the infrastructure and electrical power generation within the state. These measures will include perimeter fencing and detectors, guards, alarms, site access for employees and vendors, site personnel background checks, and law enforcement contact in the event of security breach. Other locations will have additional security measures dependent upon the results of the vulnerability assessment. The vulnerability assessment will be based, in part, on the use and storage of certain quantities of hazardous materials, including acutely hazardous materials as described by the California Accidental Release Prevention Program (Cal-ARP; Health and Safety Code, § 25531), hydrogen gas, Liquified Petroleum Fuels, sulfuric acid in concentrations greater than 90%, and any material poisonous by inhalation as defined in 49 CFR §171.8. The results of the off-site consequence analysis (OCA) prepared as part of the Risk Management Plan (RMP) will be used, among other tools, to determine the severity of consequences of a catastrophic event.

Site access for vendors shall be strictly controlled. Consistent with current state and federal regulations governing the transport of hazardous materials, hazardous materials vendors will have to maintain their transport vehicle fleet and employ only drivers properly licensed and trained. The project owner will be required, through the use of contractual language with vendors, to ensure that vendors supplying hazardous materials strictly adhere to the U.S. Department of Transportation (DOT) requirements for Hazardous Materials vendors to prepare and implement security plans as per 49 CFR 172.800 and to ensure that all hazardous materials drivers are in compliance with personnel background security checks as per 49 CFR Part 1572, Subparts A and B.

The CPM may authorize modifications to these measures, or may require additional measures depending on circumstances unique to the facility, and in response to site operator and/or industry-related security concerns.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than 50 percent within a six-mile radius of the proposed BEP II (please refer to **Socioeconomics Figure 1** in this Staff Assessment, or figure 7.6-7 of the AFC). However, as indicated in **Socioeconomics Figure 1**, there are 2 census blocks with greater than 50 percent minority persons within the six-mile radius; staff considers these to be pockets or clusters. One of these minority pockets (census tract 458) includes both BEP I and BEP II in the eastern portion of the Tract. This Tract includes the Mesa Verde community located approximately 2.25 miles southwest of the BEP II site (BEP II 2002d Section 7.6.3 and Figure 7.6-7). Staff also reviewed Census 1990 information that shows the low-income population is less than fifty percent within the same radius.

Because staff has determined there to be pockets or clusters of minority population within the six-mile radius, staff has conducted a focused environmental justice analysis for **Hazardous Materials Management**.

Based on the analysis presented in this document, staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project, and therefore there are no environmental justice issues from the use or transport of hazardous materials related to this project.

FACILITY CLOSURE

The requirements for handling of hazardous materials remain in effect until such materials are removed from the site regardless of facility closure. Therefore, the facility owners are responsible for continuing to handle such materials in a safe manner, as required by applicable laws. The **General Conditions** section of this report discusses planned, unexpected temporary, and unexpected permanent closure. Staff's General Conditions for Facility Closure require preparation of an on-site contingency plan, which must provide for removal of hazardous wastes and draining of all chemicals from storage tanks and other equipment for temporary closures exceeding 90 days or for unexpected permanent closure. Additionally, if hazardous materials become hazardous wastes by virtue of spillage or non-use, the requirements found in the FSA section on **WASTE MANAGEMENT** must be followed and will be enforced.

For planned permanent closure, BEP II would develop a facility closure plan at least twelve months prior to commencement of closure and is committed to complying with LORS that are applicable at the time of closure.

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, Riverside County Hazardous Materials Division, 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.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

AGENCY COMMENTS

none received

PUBLIC COMMENTS

Mr. Tony C. DeBacca commented that it was unclear that the Hazardous Materials Management Plan was required by a Condition of Certification.

Response: Proposed COC HAZ-2 clearly states that an HMMP is required.

APPLICANT'S COMMENTS

The applicant provided written comments in April 2004 and noted the following:
a. the Section on Setting should refer to 335 feet above seas level, not 390 feet;
b. note that an EDTA-based sytem may be used to clean the HRSG instead of hydroxyacetic acid, formic acid, or HCl; and
c. the proposed staff requirement for a berm to limit any HCl spill to 500 sq. feet should apply only to the undiluted acid, not after being diluted with water in the HRSG or water/steam system piping.

Response:
a. A correction has been made to reflect this level.
b. The staff assessment has been revised to reflect this potential use of EDTA.
c. The staff assessment has been revised to show that the proposed COC for a berm applies only to HCl when undiluted.

Mr. Thomas Cameron, Project Manager, Caithness Blythe II commented at the January 26, 2005 workshop on staff's request that the applicant seriously consider the use of an aqueous solution of lithium bromide as the turbine inlet chiller.

Response: Staff is requesting that the applicant investigate and consider this alternative chiller system. The applicant stated at the January 26, 2005 workshop that it may not be possible to use this alternative for various technical reasons and other reasons relating to the warranty of the combustion turbine. The applicant did, however, conduct an investigation and analysis and reported to staff in a March 1, 2005 letter that for several reasons, the use of a lithium bromide absorption chiller would not be an appropriate choice for inlet chilling for this project. These reasons include operational and economic impacts, steam and hence MW loss for the steam turbine generator, incompatibility with dry cooling in Blythe's climate, higher capital costs than ammonia refrigeration, and higher operating costs. Staff evaluated these reasons and finds them to be accurate and thus the applicant's position appears to be reasonable.

The Applicant has also requested that they be allowed to rely on the HazMat COCs already in-place for BEP I instead of adding new conditions.

Response: It is not appropriate to rely on the COCs for BEP I for several reasons. First, this is a new and separate project and thus reliance on requirements for one power plant may not be adequate in terms of resources, response times, communication, responsibility, and personnel allocation. Second, the accidental release of anhydrous ammonia in September 2004 at the BEP I power plant underscored the need for additional safety measures – both administrative and engineering controls – to be placed at BEP I. These additional measures were not included in the HazMat COCs for BEP I but have been included in the COCs for BEP II (see COCs **HAZ-8** and **HAZ-11**). And third, the presence of BEP II places two power plants in the same fire service jurisdiction and thus, increases impacts on fire services. These impacts were independently assessed by the Fire Service Needs Assessment which addressed

HazMat response, training, and equipment (see section on On-site Spill Resposne, above and staff assessment section on **WORKER SAFETY AND FIRE PROTECTION**).

CONCLUSIONS AND RECOMMENDATIONS

Staff's evaluation of the proposed project (with staff's proposed mitigation measures) indicates that hazardous materials use will not pose a significant risk to 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 US EPA, Riverside County, and Energy Commission staff. In addition, staff's proposed Conditions of Certification require Riverside County's review, and staff review and approval of the RMP prior to delivery of any hazardous materials to the facility. Other proposed Conditions of Certification address the issue of the transportation, storage, and use of aqueous ammonia and the use of anhydrous ammonia as a refrigerant.

Staff recommends the Energy Commission impose 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. If all mitigation proposed by the applicant and by staff are required, the use, storage, and transportation of hazardous materials will not present a significant risk to the public.

PROPOSED CONDITIONS OF CERTIFICATION

HAZ-1 The project owner shall not use any hazardous materials not listed in Appendix B, below, or in greater quantities 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 Compliance Project Manager (CPM), in the Annual Compliance Report, a list of hazardous materials contained at the facility.

HAZ-2 The project owner shall concurrently provide a Business Plan (including a Hazardous Materials Management Plan) and a Risk Management Plan (RMP) to the Certified Unified Program Authority – (CUPA) (Riverside County Hazardous Materials Division) and the CPM for review at the time the RMP is first submitted to the U.S. Environmental Protection Agency (EPA). After receiving comments from the CUPA, the EPA, and the CPM, the project owner shall reflect all recommendations in the final documents. Copies of the final Business Plan and RMP shall then be provided to the CUPA and EPA for information and to the CPM for approval.

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 for approval. At least sixty (60) days prior to delivery of aqueous ammonia to the site, the project owner shall provide the final RMP to the CUPA for information and to the CPM for approval.

HAZ-3 The project owner shall develop and implement a Safety Management Plan for delivery of aqueous ammonia. The plan shall include procedures, protective equipment requirements, training and a checklist. It shall also include a section describing all measures to be implemented to prevent mixing of aqueous ammonia with incompatible hazardous materials.

Verification: At least sixty (60) days prior to the delivery of aqueous ammonia to the facility, the project owner shall provide a safety management plan as described above to the CPM for review and approval.

HAZ-4 The aqueous ammonia storage facility shall be designed to either the ASME Pressure Vessel Code and ANSI K61.6 or to API 620. In either case, the storage tank shall be protected by a secondary containment basin capable of holding 125% of the storage volume or the storage volume 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.

Verification: At least sixty (60) days prior to delivery of aqueous ammonia to the facility, the project owner shall submit final design drawings and specifications for the ammonia storage tank and secondary containment basin to the CPM for review and approval.

HAZ-5 The project owner shall ensure that no flammable material is stored within 50 feet of the sulfuric acid tank.

Verification: At least sixty (60) days prior to receipt of sulfuric acid on-site, the Project Owner shall provide copies of the facility design drawings showing the location of the sulfuric acid storage tank and the location of any tanks, drums, or piping containing any flammable materials

HAZ-6 The project owner shall direct all vendors delivering aqueous ammonia to the site to use only tanker truck transport vehicles which meet or exceed the specifications of DOT Code MC-307 and that all vendors delivering anhydrous ammonia to the site use only tanker truck transport vehicles which meet or exceed the specifications of DOT Code MC-330 or 331.

Verification: At least sixty (60) days prior to receipt of aqueous 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-7 The project owner shall direct all vendors delivering any hazardous material to the site to use only the route approved by the CPM (I-10 to Neighbors Boulevard. to Hobsonway to Buck Boulevard). The project owner shall obtain approval of the CPM if an alternate route is desired.

Verification: At least sixty (60) days prior to receipt of any hazardous materials on site, the project owner shall submit copies of the required transportation route limitation direction to the CPM for review and approval.

HAZ-8 The project owner shall develop and implement an Ammonia Refrigeration Hazard Reduction Plan. This plan shall include procedures, protective equipment requirements, training and a checklist, as described in the August 2001 EPA Chemical Safety Alert. It shall also include a section describing all

measures to be implemented to prevent the leaking of anhydrous ammonia from the refrigeration system. This plan shall also incorporate recommended practices as found in ANSI Standards 15-2001 and 34-2001 and the ASHRAE Position Document on Ammonia As A Refrigerant (January 17, 2002). The applicant shall also include appropriate elements of the Cal-OSHA Process Safety Management standard (8 CCR section 5189).

Verification: At least sixty (60) days prior to the delivery of anhydrous ammonia to the facility, the project owner shall provide a safety management plan as described above to the CPM for review and approval.

HAZ-9 When cleaning the HRSG, the project owner shall provide or contract to provide temporary berm(s) to contain any spill of HCl to no more than 500 square feet in size.

Verification: At least sixty (60) days prior to delivery of the initial HRSG cleaning chemicals to the site, the project owner shall submit final design drawings and specifications for the temporary surface containment berm(s) to the CPM for review and approval.

HAZ-10 The project owner shall install an approved automatic fire suppression system in the ammonia refrigeration plant.

Verification: At least sixty (60) days prior to delivery of anhydrous ammonia to the facility, the project owner shall provide final design drawings and specification for the fire protection system approved by a registered Safety Engineer to the CPM for review and approval.

HAZ-11 The project owner shall install an ammonia sensor on the discharge from the scrubber on the anhydrous ammonia containment building that can be remotely read in the power plant control room. This sensor and all other sensors located inside the containment building shall be able to detect ammonia concentrations within a range of 10 to 800 ppm and shall be reported to the power plant control room on a real-time recordable basis. Additionally, the project owner shall install power overhead doors in the containment building that close via an electronic actuator as well as manually.

Verification: At least sixty (60) days prior to delivery of anhydrous ammonia to the facility, the project owner shall provide final design drawings and specification for the above systems to the CPM for review and approval.

HAZ-12 The project owner shall investigate and consider the use of an aqueous solution of lithium bromide as a refrigerant in the inlet air chiller system.

Verification: At least sixty (60) days prior to delivery of anhydrous ammonia to the facility, the project owner shall provide a report on the possible use of a lithium bromide air chiller system to the CPM for review.

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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.

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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

[AFC Table 7.9-2 from the revised Hazardous Materials Handling section Dated July 2002 Amended April 2004]

Table 7.9-2
BEP II Chemicals

Trade Name	Chemical Name	CAS Number (a)	Maximum Quantity On-Site	Hazardous Character	CERCLA SARA RQ (b)	La Follette Bill TPQ (c)	Prop. 65
Acutely Hazardous Materials							
Aqueous Ammonia (19 to 30% solutions)	Ammonium Hydroxide	1336-21-6 (for NH_3 plus H_20)	20,000 gallons or 120,000 pounds	Corrosive and Volatile	100 pounds	500 pounds	No
NALCO 356 or Equivalent	Cyclohexylamine (20 to 40%) Morpholine (5 to 10%)	108-91-8 110-91-8	2,000 gallons	Corrosive	40,000 pounds	NA	No
TRIACT 1800 or Equivalent	Ethanolamine (10 to 20%) Methoxyropylamine (10 to 20%) Cyclohexylamine (10 to 20%)	141-43-5 5332-73-0 108-91-8	2,000 gallons	Corrosive	100,000 pounds	NA	No
Hazardous Materials							
Sulfuric Acid	Sulfuric Acid	7664-93-0	6,000 and 2,000 gallons	Corrosive	1,000 pounds	NA	No
Aluminum Sulfate	Aluminum Sulfate	10043.01-3		Toxic	5,000 pounds	NA	No
Bleach	Sodium Hypochlorite	7681-52-9	6,000 gallons	Corrosive	100 pounds	NA	No
Sodium Hydroxide	Sodium Hydroxide	1310-73-2	6,000 gallons	Corrosive	1,000 pounds	NA	No
Disodium Phosphate	Sodium Phosphate	7558-79-4	500 pounds	Toxic	(d)	NA	No
Trisodium Phosphate	Tri-Sodium Phosphate	760-54-9	500 pounds	Toxic	(d)	NA	No
Ammonium Bifluoride	Ammonium Bifluoride	N/A	200 pounds	Toxic	(d)	NA	No
Sodium Carbonate	Sodium Carbonate	N/A	500 pounds	Toxic	(d)	NA	No
Hydrochloric Acid	Hydrochloric Acid	7647-01-0	10,000 gallons	Corrosive	5,000 pounds	NA	No
Citric Acid or Equivalent	Hydroxy-propoinic-tricarboxylic Acid	77-7279	500 pounds	Corrosive	(d)	NA	No
Hydroxy Acetic Acid	Gyrolic Acid	N/A	1,000 pounds	Corrosive	(d)	NA	No
Formic Acid	Methanoic Acid	64-18-6	600 pounds	Corrosive	5,000 pounds	NA	
							No

Table 7.9-2
BEP II Chemicals

Trade Name	Chemical Name	CAS Number (a)	Maximum Quantity On-Site	Hazardous Character	CERCLA SARA RQ (b)	La Follette Bill TPQ (c)	Prop. 65
STABREX ST70 or Equivalent	Sodium Hydroxide (1 to 5%) Sodium Hypobromite (10 to 20%)	1310-73-9 13824-96-9	2,000 gallons	Corrosive and Toxic	30,800 pounds	NA	No
NALCO 7280 or Equivalent	Polyacrylic Acid (20 to 40%)	Trade Secret	250 gallons	Toxic	(d)	NA	No
ELIMIN-OX or Equivalent	Carbohydra-zide	497-18-7	2,000 gallons	None		NA	No
NALCO 7408 or Equivalent	Sodium Bisulfite (40 to 70%)	7631-90-5	250 gallons	Corrosive	12,000 pounds	NA	No
NALCO 22106 NALCO 7213 or Equivalent	Sodium Plyacrylate Aryl Sulfonate Tetrasodium ethylenedia-minetetraace-tate (10 to 20 %)	N/A 64-02-8	2,000 gallons	Toxic Corrosive	(d) (d)	NA	No No
Mineral Insulating Oil	Oil	None	25,000 to 40,000 gallons	Combustible	42 gallons (e)	NA	Yes
Lubrication Oil	Oil	None	12,000 gallons	Flammable	42 gallons (e)	NA	Yes
Hydraulic Oil	Oil	None	600 gallons	Flammable	42 gallons (e)	NA	Yes
Various Detergents	Various	None	100 gallons	Toxic	(c)	NA	No
Laboratory Reagents	Various	None	Small Quantities	Toxic	(c)	NA	No
Laboratory Reagents (Solids)	Various	None	Small Quantities	Toxic	(c)	NA	No

CAS = Chemical Abstract Service
Reportable quantity per CERCLA. Release equal to or greater than RQ must be reported. Under California law, any amount that has a realistic potential to adversely affect the environment or human health or safety must be reported.
Threshold Planning Quantity (TPQ). If quantities of acutely hazardous materials equal to or greater than TPQ is handled or stored, they must be registered with the local Administering Agency (AA). For hazardous materials, the TPQ is 10,000 pounds.
No reporting requirements.
Must be reported if it does or will reach California State waters or if the quantity released is a "harmful quantity".

LAND USE

Testimony of David Flores

INTRODUCTION

The land use analysis of the Blythe Energy Project Phase II (BEP II) focuses on two main issues: (1) project consistency with the land use laws, ordinances, regulations standards, plans and policies, and (2) project 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.

The major concerns with BEP II land use compatibility are the project's potential for direct and indirect impacts on agricultural uses, conflict with airport operations at the Blythe Airport located approximately one mile to the west of the project site, and cumulative impact in combination with other planned projects. Additional details regarding potential impacts on airport safety are provided in the **TRAFFIC AND TRANSPORTATION** section of the Final Staff Assessment (FSA).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

This section describes federal, State, regional, and local land use laws, ordinances, regulations, and standards (LORS) applicable to the proposed project.

FEDERAL

There are no federal land use LORS that affect BEP II. The applicable federal aviation regulations are summarized in the **TRAFFIC and TRANSPORTATION** section.

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. This Act vests regulation and control of the design and improvement of subdivisions in local municipalities. Each local municipality 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.

LOCAL

County

Land Use Element

The Riverside County Comprehensive General Plan (RCCGP) Land Use Element is the primary policy statement for implementing the development and conservation goals of the County's General Plan. The Countywide policies for land use compatibility, population levels, public facility levels, environmental constraints and community policies are also contained within the General Plan. The County continuously updates the Land Use Element using data on current conditions to revise the General Plan's maps and diagrams.

The Land Use Element contains policies specific to the Palo Verde Valley Area. The overall policy for future land uses in this area is for continued agricultural land uses, with urban uses directed to the City of Blythe's Sphere of Influence. The Element states that industrial development should occur within this sphere of influence, south of Blythe along the Arizona and California Railroad line (formerly AT&SF) and adjacent to the Blythe Airport (RCCGP, p. 99).

Environmental Hazards and Resources Element

The Environmental Hazards and Resources Element contains an open space and conservation inventory and related map, which delineate those areas that have significant open space or conservation value. These areas may include agricultural lands, parks and recreation areas, vegetation resources, wildlife resources, scenic highways, historic resources, energy resources, fire hazard areas, seismic/geologic hazard areas, slope areas, flood hazard areas, noise impacted areas and other natural resources and hazards. Mapped land uses include open space, recreation, agriculture, mining, research and related compatible land uses (RCCGP, p. 368).

The Open Space and Conservation land use standards include the following: "The open space characteristics of the County, including the rivers, the mountains, the deserts, and the productive agricultural lands shall be protected." (RCCGP, p. 376)

Agriculture objectives include: "1. Agriculturally productive lands shall be encouraged to remain in agricultural uses." (RCCGP, p. 377) Riverside County participates in the Williamson Act Program. Lands placed in agricultural preserve are restricted to agriculture and compatible uses (RCCGP 1984 p. 378) such as electric transmission lines, gas pipelines, low density residential, and flood control structures.

CITY OF BLYTHE 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.

In September of 1989, the City of Blythe approved a comprehensive general plan for the incorporated City and the City's Sphere of Influence. A much larger study area covering 63 square miles was addressed, but is not under the jurisdiction of the City. The City General Plan applies only to those areas within the City's incorporated boundary and Sphere of Influence.

City of Blythe Land Use Element

The City General Plan designation for the power plant site is Heavy Industrial (I-H) (See **LAND USE Figure 1, City of Blythe General Plan Designations**). According to the General Plan, the Heavy Industrial designation provides for the most intense industrial development to be contemplated in the City. Uses associated with this designation may include power plants, slaughterhouses, rendering plants, metals smelting and/or manufacturing, refining oils and other flammable or hazardous materials, and other uses which may require extensive outdoor storage areas or materials handling.

The City General Plan land use categories are described below (Blythe1989, p. III-2):

Agricultural Reserve consists of land in active or potentially active cultivation and sufficiently removed from urban development to warrant protection.

Residential Reserve serves as an intermediate land use designation buffering agricultural lands from urban residential development. This category precludes premature expansion of urban development.

Urban Reserve consists of land in the sphere of influence and outlying planning areas planned for future urban core development. This category requires a specific plan.

Heavy Industrial provides for industrial uses which are relatively intense and which may also include extensive outdoor storage.

Agricultural Land Use Goals and Policies

The project site has both a General Plan designation and zoning classification for industrial use. However, this LORS section also discusses the agricultural land use goals and policies of the City General Plan in the LORS section because the site is adjacent to agricultural lands, and the applicant's Water Conservation Offset Program (WCOP) (discussed later in this analysis) may have an impact on the implementation of agricultural goals and policies.

The Agricultural Reserve designation is assigned to lands which are in active or potentially active cultivation, and which are sufficiently removed from urban development to warrant protection and preservation. These lands are generally composed of larger holdings, which make ongoing cultivation viable. This designation also may be assigned to areas where farm structures and residences occur, but is not applicable to agriculture-related industrial land uses (Blythe 1989, p. III-26). Agricultural goals and policies contained in the City Land Use Element encourage the retention of agricultural lands in agricultural use (Blythe 1989, pp. III-25-26). Agricultural Reserve goals relevant to the project are as follows (Blythe 1989, pp. III-25):

- To preserve and protect agricultural lands from premature or inappropriate intrusion of urban or other adverse land uses, which threaten the long-term viability of agricultural activities.
- Assure the thoughtful integration of agricultural lands with other land uses, assuring that these lands will continue to provide open space relief from the urban development of the City.

Agricultural Reserve Policies relevant to the project are as follows (Blythe 1989, p. III-26).

- The City shall protect agricultural lands from premature development by assuring the logical and coherent expansion of urban development in the City.
- The City shall encourage the continuation of agricultural activity on undeveloped land as a method of assuring their on-going use and function as rural open space areas.
- Preservation of agricultural lands and prime soils in non-urban areas shall be fostered in order to retain the viability of the groundwater aquifer, which serves the City.

Agricultural Resources Element

The City Agricultural Resources Element contains the following goal which is relevant to the project (Blythe 1989, p. IV-29):

- Maintain, protect and enhance the viability of the agricultural resources of the Palo Verde valley, while providing for increasing urbanization within the City, Sphere and Study Area.

City of Blythe Zoning Ordinance

The City of Blythe Zoning Ordinance establishes land use (zone) districts in the City's incorporated 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 City, protecting existing development, encouraging beneficial new development, and preventing overcrowding and congestion.

The City has zoned the power plant site General Industrial (I-G). The General Industrial zone allows a variety of manufacturing uses by right including public maintenance services, utility operations facilities, custom manufacturing, general manufacturing, and heavy industrial uses and warehousing in accordance with §17.08 010 of the City Zoning Ordinance. City zoning designations for lands within one mile of the power plant site are Agriculture (A) to the east, and Service Industrial (I-S) to the south between I-10 and Hobsonway. See **LAND USE Figure 2**, **City of Blythe Zoning.**

RIVERSIDE COUNTY AIRPORT LAND USE COMMISSION

The Comprehensive Land Use Plan

The *Comprehensive Land Use Plan for Blythe Airport, Riverside County, California (CLUP)* was adopted by the Riverside County Airport Land Use Commission (ALUC) in August of 1992. The purpose of the CLUP is to protect and promote safety and welfare

of residents of the airport vicinity and users of the airport while ensuring the continued operation of the airport. Where local general plans or specific plans are not consistent with the CLUP, State law enables the ALUC to require the local agencies to submit all development actions, regulations, and permits to the ALUC for review.

The ALUC is established under the authority of California Government Code Sections 21670 et. seq. and is charged with formulating a comprehensive land use plan for the area surrounding each public use airport in its jurisdiction. The ALUC, appointed by the County Board of Supervisors, makes determinations of consistency of proposed development projects on an advisory basis for the permitting jurisdiction. The local permitting agency can overrule a determination by the ALUC by a two-thirds vote of its governing body. However, in the case of certification of energy projects over 50 megawatts, the Energy Commission's certifying power takes precedence over local government (Public Resources Code Par. 25505). The Energy Commission staff puts great weight on comments and recommendations of local governmental agencies in its review process. (Cal. Code Regs,. Tit. 20, §1714.5)

SETTING

SITE AND VICINITY DESCRIPTION

The BEP II site is located about 5 miles west of downtown Blythe in eastern Riverside County, in a recently-annexed portion of the City of Blythe and about one mile east of the Blythe Airport. The site is located approximately 1,000 feet north of Interstate 10 (I-10), a major regional transportation corridor extending east-west through the area. **See LAND USE Figure 3**, **Regional Location of the Proposed Project**.

The BEP II power plant site is located within a 1,253-acre area recently annexed to the City, which extends from the City's previous western boundary to the eastern boundary of the Blythe Airport property. The annexation became final on November 28, 2000. The BEP II site is located in an area called Mesa Verde (the Mesa), above the Palo Verde Valley floor.

The project site is located in the Palo Verde Valley area of the County, which is an intensive agricultural region. Commodities grown in the area include citrus, melon, vegetable, and field crops such as alfalfa. Nearly all of the cultivated areas are irrigated with water from the Colorado River aquifer, supplied from the Palo Verde Irrigation District or from domestic wells.

BEP II would be built on the 76-acre expansion portion of the original 76-acre Blythe Energy Project Phase I (BEP I) site, on the west side of the original site. The entire BEP I/BEP II 152-acre site is to the north of and adjacent to Hobsonway, a two-lane arterial road oriented East-West, and to the west and adjacent to Buck Boulevard. Hobsonway is a four-lane local arterial road that connects the Blythe Airport with the City of Blythe. The construction of BEP I has recently been completed on the original site, and the expansion site has been used for storage of approximately 200,000 cubic yards of excess soils from construction of the BEP I evaporation ponds and retention basin. This soil has been graded, compacted and stabilized on the BEP II site.

SURROUNDING LAND USE

Land uses surrounding the site include: the Blythe Airport facilities, large parcel agriculture, electric utilities, highways, and residential and industrial structures. Specific surrounding uses are described as follows with the approximate distances from the project site:

- the Blythe Substation located about 2,000 feet to the east;
- the Blythe Airport located approximately one mile to the west;
- an unincorporated residential community within the Mesa Verde area, located approximately 2 miles southwest;
- isolated farm and other residences near the project site, primarily located south and east;
- a small industrial area to the north;
- a small sewage treatment facility about 0.25 mile to the west;
- Interstate 10 corridor approximately 0.25 mile to the south;
- a U.S. Border Patrol facility over one mile to the west; and
- the Blythe Trap Shooting Club and the Riverside County Animal Shelter, both about one mile to the west.

Properties immediately adjacent and to the west, north and south (across Hobsonway) are undeveloped. The property to the immediate east is a declining lemon grove. Western Area Power Administration (Western) owns the Blythe Substation. The Substation occupies a site approximately 12 acres in size, surrounded on three sides by the lemon grove. The Blythe Substation connects five existing 161-kV transmission lines serving the region.

Except for agriculture and some scattered residences and industrial uses, the properties within one mile of the power plant site are largely undeveloped. Highway-serving commercial uses are located on the north side of Interstate 10 (I-10) at the interchange south of the Blythe Airport. The Blythe Airport is described in detail below.

Blythe is the only incorporated city within the Palo Verde Valley planning area. Unincorporated communities in the Palo Verde Valley Area include Mesa Verde (Nicholls Warm Springs), located approximately 2 miles southwest of the project site; and Ripley, located approximately 6 miles to the south of the City and the project site. The predominant land use in the area is irrigated agriculture and related enterprises. Other land uses include residential, and recreational development mainly focused on the Colorado River, which borders the City of Blythe on the east. Commercial land uses serve the needs of agriculture, local residents, pass-through travelers, and recreational visitors. I-10 is a major interstate and regional transportation corridor, which extends east-west through the area.

Mesa Verde is the largest concentration of residential land uses in the proximity of the project. The major residential portion of the City of Blythe is located about five miles to the east. There are small numbers of farm and other residents near the site, mostly

located south and east of the project site. The nearest residence is located 0.75 mile southwest of the power plant site (BEP II 2002a, p. 7.2-4).

Blythe Airport

The Blythe Airport is located approximately one mile west of the proposed BEP II power plant site. The Blythe Airport is the largest airport serving eastern Riverside County and serves primarily general aviation demand in the Blythe area. The Airport is classified in the National Plan of Integrated Airport Systems as a general aviation transport airport, designed to accommodate business jets, cargo type aircraft, light private planes, and flight school training activities. The Blythe Airport currently has two runways. The primary runway is Runway 8-26, which is oriented generally east-west. The BEP II power plant stacks would be located approximately 4,450 feet southeast of this runway, which is situated at an elevation of 393 feet mean sea level (MSL). The elevation of the BEP II site is about 335 feet MSL (BEP II 2002a, 7.4-8). Therefore, the 130-foot heat recovery stream generator (HRSG) stacks would be about 72 feet higher than the end of the runway. The project's on-site transmission towers are single circuited, and will be approximately 125 feet tall. Please refer to the **TRAFFIC AND TRANSPORTATION** section of the FSA for details regarding Blythe Airport operations and facilities.

The Blythe Airport has been designated as a County redevelopment area. The intent is to encourage expansion of airport facilities and commercial and industrial development at the airport. The County's redevelopment plans are described in the Riverside County *Redevelopment Plan for Redevelopment Project Airports*, County of Riverside Economic Development Agency 1988 (Coffman, p. 2-18).

Agriculture

The BEP II power plant site is not currently used for agricultural production, nor does it appear to have been cultivated in the past. The site is classified as Farmland of Local Importance[1]. Similar soil types occur on the irrigated lands immediately adjacent, to the east of the site, which are designated Prime Farmlands[2], and contains a declining lemon grove.

PROJECT FEATURES

The project site consists of four parcels with a total area of 152 acres. BEP I construction has been completed on the original 76-acre site, parcels 34 and 35. BEP II would be constructed on the adjacent 76-acre extension site to the west, parcels 36 and 37.

The project would consist of a 520 MW combined cycle power plant, to be interconnected to the Buck Boulevard Substation in the northeast corner of the BEP I site.

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[1] Farmland of Local Importance is land of importance to the local agricultural economy as determined by each County's board of supervisors and local advisory committees, and noted on the California Department of Conservation Important Farmland Map" for Riverside County (DOC).

[2] Prime Farmland is land that has the best combination of physical and chemical characteristics for the production of crops. It has the soil quality, growing season, and moisture supply needed to produce sustained yields of crops when treated and managed, including water management, according to current farming methods. Prime farmlands must have been in production of irrigated crops at some time during the update cycles prior to the California Department of Conservation's (DOC) Important Farmland mapping date.

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 the 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 an established community;
- Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance, as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to a non-agricultural use;
- Conflict with existing zoning for agricultural use, or a Williamson Act contract; or
- Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland to non-agricultural uses.

A project may also have a significant impact on land use if it will create unmitigated noise, dust, public health hazard or nuisance, traffic, or visual impacts, or when it precludes or unduly restricts existing or planned future uses.

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 LORS and policies applicable to the project have been analyzed below to determine the extent to which BEP II is consistent with each requirement or standard.

State

Subdivision Map Act, 1972

BEP II would be located entirely within the BEP I site's expanded boundaries. The site is located in the eastern half of the NW1/4, Section 33, T6S, R22E. The site is comprised of four parcels. BEP I has been constructed on Parcels 34 and 35; a lot line adjustment was recorded with Parcel 34 to create a separate Parcel "B" for the Buck Boulevard Substation. BEP II would be located on the expansion portion of the site, parcels 36 and 37 and is not owned by the same entity as BEP I. The BEP II facilities would occupy approximately 10.45 acres of the property excluding the evaporation ponds and the cultural resources avoidance area which consist of approximately 7.5 acres (BEP II 2003a, p. 27). Condition **LAND-5** would require a lot line adjustment creating one parcel accommodating or containing all project facilities, except for linear facilities.

Local

Riverside County

If the applicant's implementation of its WCOP includes the permanent retirement of irrigated lands, the WCOP could be inconsistent with the County General Plan policies in the Land Use Element and the Environmental Hazards and Resources Element related to preservation of agricultural land noted above. See the "Water Conservation Offset Program" section found later in this report for a further discussion on the applicant's proposal for implementing the WCOP.

City of Blythe General Plan

The City General Plan designates the BEP II site as Heavy Industrial (I-H). The project is consistent with this designation, and the City's goals for new additional industrial development.

The proposed project is generally compatible with land uses immediately adjacent to the site, which consist of an orchard on the east side and vacant land on the remaining areas. In general, the City's agricultural goals and policies encourage the continuation of agricultural use in the incorporated area. However, BEP II is potentially in conflict with these goals and policies if the proposed WCOP includes permanent retirement of irrigated land. In this case implementation of the WCOP would reduce prime farmland acreage, and without mitigation, would be a significant impact. (see the discussion on the WCOP below under "Compatibility with Existing and Planned Land Uses"). The project's compatibility with the Blythe Airport is discussed under the "Compatibility with Existing and Planned Land Uses" heading also.

City of Blythe Zoning Regulations

The General Industrial Zone allows a variety of manufacturing uses by right including public maintenance services, utility operations facilities, custom manufacturing, general manufacturing, and warehousing in accordance with §17.08 010 of the City of Blythe Zoning Ordinance. The proposed power plant would be considered a Utility Operations Facility as defined in §17.08.710 of the City of Blythe Zoning Ordinance and allowed by

right in the Heavy Industrial zone (Petritz 2002a). This zone, however, does contain a maximum height restriction of thirty-four (34) feet (§17.10.040 of the City of Blythe Zoning Ordinance). The heights of structures included in the design of the proposed power plant that may exceed the zoning district height limitations are listed below. Some of these structures may fall within the definitions included in City Zoning Ordinance Par. 17.10.041, "Commercial broadcast antennas, communications towers and microwave masts", and would be within the maximum height identified in this paragraph of 109 feet (Petritz 2002b).

Generation Building	60 feet
Heat Recovery Steam Generator (HRSG) Stack	130 feet
Heat Recovery Steam Generator	93 feet
Cooling Tower	40 feet
Raw Water Supply Tank	43 feet
Demineralized Water Storage Tank	43 feet
Brine Concentrator	98 feet
Transmission Lines	95 feet (or 145 feet if double-circuited)

On March 8, 2004, the City of Blythe Planning Department approved a height variance request for three, 125-foot transmission towers, two, 130-foot high exhaust stacks, and one, 99-foot high brine concentrator. In addition, the City's Project Review Committee (PRC) reviewed the project and recommended conditions of approval to the City for review and approval. On March 23, 2004, the City Council, by Minute Order approved the recommended conditions which were forwarded to the applicant and the Energy Commission for inclusion in the Conditions of Certification for each responsible section.

No conditions were identified by the PRC for land use issues, although a site development plan will be required by Energy Commission staff, and the project must comply with the applicable design criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance. The site development plan must contain the following features:

a. Setbacks (i.e. yard area requirements) for structures;

b. Building elevations;

c. Temporary and permanent signs for project identification (permanent and construction phase signs);

d. Permanent parking lot design, showing the quantity and dimension of spaces;

e. Parcel lot lines; and

f. Landscaping

See the **VISUAL RESOURCES** section of this FSA for a discussion of landscaping requirements.

LAND-1 would require that the applicant submit evidence of City review during project construction demonstrating compliance with the approved site plan. **LAND-2** would

require that the applicant submit to the City of Blythe descriptions of the final laydown/staging areas for the City's review and comment.

Blythe Airport Comprehensive Land Use Plan

As described in the *CLUP,* five safety zones are defined around airports to promote the safety of persons on the ground while reducing risks of serious harm to crews and passengers of aircraft making forced landings in the immediate environs of the airport. The CLUP provides land use compatibility guidelines that apply to each of these zones. These zones are the:

- Inner Safety Zone (ISZ);
- Outer Safety Zone (OSZ;);
- Emergency Touchdown Zone (ETZ);
- Traffic Pattern Zone (TPZ); and the
- Extended Runway Centerline (ERC).

As shown in **LAND USE FIGURE 4, Blythe Airport Safety Zones**, the 152-acre power plant site is within four of these safety zones: the OSZ, the ETZ, the TPZ, and the ERC. The BEP II project structures within the site, which would occupy approximately 10 acres, are entirely in the TPZ. The adjacent, existing BEP I structures also occupy about 10-acres, which are within the ERC and TPZ zones. The CLUP's descriptions and land use compatibility guidelines for these latter four zones and the ISZ are as follows (Coffman, pp. 3-4 - 3-6):

- The ISZ is an area immediately off the runway end, 1,500 feet wide and from 1,320 to 2,500 feet long, depending on the type of runway approach and the type of aircraft using the runway. An area of significant accident risk, no structures should be permitted in this zone.
- The OSZ is an area along the ERC immediately beyond the ISZ, which is 1,500 feet wide and ranges from 2,180 to 2,500 feet long. Structures should not cover more than 25% of the lot. The OSZ should contain no public utility stations or plants, and no uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials.
- The ETZ is a 500-foot wide area extending from the primary surface of the airport runway to the end of the OSZ and is intended as an emergency landing area. This area has the greatest accident risk, so no structures or significant obstructions should be permitted.
- The TPZ is the area around the airport that is most frequently flown over by aircraft and within which the local traffic pattern is located. This zone extends approximately 10,000 feet off the ends and sides of runways. Structures should occupy no more than 50 percent of the gross development area or 65 percent of the net lot area, whichever is greater. There should be no uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials."
- The ERC is 1,000 feet wide and extends 5,000 feet off of the end of the OSZ. Structures should occupy no more than 50 percent of the gross development area or 65 percent of the net lot area, whichever is greater. There should be no land uses

involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials.

The CLUP states that any uses posing the following risks to aircraft in flight shall be prohibited within all safety zones (Coffman, p. 7-6):

- light and reflection interference;
- smoke, or water vapor;
- gathering of birds; and
- electrical interference.

The CLUP includes from the State Airport Land Use Planning Handbook (Caltrans, 2002) detailed descriptions of these risks, including any use "which may otherwise affect safe air navigation within this area." (Coffman, p. 3-7)

Regarding these risks, the CLUP states (Coffman, p. 7-6):

- Only a few kinds of land uses have inherent attributes that would make them necessarily violate these standards. (Landfills and power generating plants are examples.)

The CLUP did not elaborate on the inherent attributes which cause power plants to trigger these risks and/or standard violations. Although, based on the ALUC staff report dated July 18, 2002, that addresses the proposed project, water vapor can attract large concentrations of birds, which may affect safe air navigation within the area.

The key power plant structures comprising BEP II would occupy approximately 10.45 acres of the 76 acre expansion site (BEP II 2003a, p. 27). Thus, structures would occupy less than 50 percent of the gross lot area of the site and the project is consistent with the development area provisions of the safety zones.

The applicant states that all project features located in the safety zones are consistent with the CLUP (BEP II 2002b, p. Land-6). However, the July 18, 2002 report by the ALUC made an advisory determination that the project would be inconsistent with the CLUP (ALUC 2002a). The ALUC staff report for the project considered a number of issues related to land use in making its recommendation of inconsistency including the project's capacity to attract wildlife, the need for legal easements and project signs, lighting, sun reflection, smoke and water vapor generation, and electrical interference. The staff report noted the inherent incompatibility of power plants with the Blythe Airport if located in any of the safety zones (ALUC 2002b, p. 2), such as the BEP II's location within the airport's TPZ.

However, the ALUC staff report does not note as a safety issue the possibility of danger to air traffic from thermal plumes generated by the project, which is discussed in detail in the **TRAFFIC AND TRANSPORTATION** section of this FSA. In the case of BEP II, pursuant to the Warren-Alquist Act the Energy Commission is the permitting agency and has the jurisdiction to concur with or overrule the ALUC's determination. If the Energy Commission overrules this determination and decides to certify this project, the ALUC has recommended mitigating conditions (ALUC 2002a). However, ALUC staff has stated that even with the implementation of the conditions, the project would still be

inconsistent with the CLUP (Downs). On July 26, 2004, the City of Blythe, which has a contract with Riverside County to operate the Airport, unanimously approved Resolution No. 04-897 overriding the negative advisory vote of the ALUC. Staff does not believe that the City of Blythe's Findings support the override of the ALUC's determination and concurs with the ALUC that the project is in violation of the CLUP. Energy Commission staff believes that the land use issues noted by the ALUC staff report could be adequately mitigated through implementation of the conditions included in this FSA. However, the issue of thermal plumes, which is not included in the ALUC's staff report, would fall under the CLUP's admonition against any use "… which may otherwise affect safe air navigation…."

The thermal and visual plume studies are discussed in the **TRAFFIC AND TRANSPORTATION** section of this FSA. Condition **LAND-4** would require the applicant to comply with the ALUC's proposed conditions relevant to land use.

The CLUP also contains airport vicinity height guidelines. These guidelines are based on standards developed by the FAA for determining obstructions in the navigable airspace (See the **TRAFFIC AND TRANSPORTATION** section of the FSA). The proposed BEP II site is located below the Federal Aviation Administration (FAA) Horizontal Surface, which covers generally the same area as the TPZ. The boundaries of the Horizontal Surface are set at a radius of 10,000 feet from Runway 8-26. The elevation of the Horizontal Surface height limitation is 150 feet above the airport elevation, at an elevation of 547 feet mean sea level (MSL) (Coffman, p. 6-2). Refer to the **TRAFFIC AND TRANSPORTATION, VISUAL RESOURCES,** and **PUBLIC HEALTH** sections of this FSA for other conditions related to the ALUC recommendations.

Additional details regarding potential impacts on Airport operations are provided in the **TRAFFIC AND TRANSPORTATION** section of the FSA.

COMPATIBILITY WITH EXISTING AND PLANNED LAND USES

Power Plant Site

The proposed power plant**,** located in a largely nonurbanized area, will not physically divide an established community.

Compatibility with Airport Operations

BEP II would be located approximately one mile from the end of Blythe Airport's primary runway. Local pilots and an aviation business owner recently raised concerns regarding the hazards to aircraft using Blythe Airport. Their concerns focused on potential hazards caused by thermal and water vapor plumes from both the existing BEP I and proposed BEP II power plants (Wolfe 2003a, & 2003b). The BEP I owners have stated that the thermal and visual plumes caused by BEP I and II will not have an impact on aviation safety (BEP 2003). However, ALUC staff has stated that the effect of visual and thermal plumes could be a danger (Downs). The **TRAFFIC AND TRANSPORTATION** section of the BEP II FSA provides a thorough analysis of the impact of BEP II on airport traffic safety, which includes studies assessing the impact of visual and thermal plumes.

Compatibility with Agriculture

The proposed project would be compatible with nearby agricultural uses. The proposed project would not adversely affect agricultural practices and would not restrict normal operations of citrus orchards in the area. With the implementation of the conditions of certification contained in the **AIR QUALITY** section of the FSA that require control of fugitive dust, the project's construction activities would not adversely affect agricultural crops in the area.

The BEP II site is classified as Farmland of Local Importance. The Farmland of Local Importance designation is applied where soil types would qualify as prime farmland if the land were irrigated.

CUMULATIVE IMPACTS

Imperial Irrigation District Transmission Line

The Imperial Irrigation District (IID) has proposed construction of a new 118-mile transmission line from Buck Boulevard Substation on the BEP I site to the Southern California Edison Company's Devers Substation, approximately 10 miles north of Palm Springs. This is referred to as the Desert Southwest Transmission Line Project (DSWTP). BEP II would connect with The Buck Boulevard Substation, which may connect with the IID transmission line (See the **Transmission Systems Engineering** section (TSE) for a discussion of this proposal and alternative transmission lines under consideration). The IID's DSWTP also includes a new Substation/switching stations on Hobsonway to the west of the BEP I site and on Dillon Road adjacent to the existing transmission line facilities near Indio (BLM/IID p. ES-8).

The DSWTP would be located entirely in a BLM-designated corridor (BLM/IID p. 3.7-16). The project area is generally rural desert land with large amounts of undeveloped open space areas. The DSWTP and two other alternatives travel through or are adjacent to seven incorporated cities and several unincorporated communities in Riverside County (BLM/IID p. 3.7-3). It is not clear from available documentation how many residential units and commercial buildings, and the amount of residentially and commercially-zoned vacant property, would be impacted by the IID project. Therefore it is possible that the IID project could have a significant impact on residential and commercial units and vacant property. However, because BEP II does not have an impact on residential or commercial units and vacant property, any such impact by the DSWTP would not be a cumulative impact in combination with BEP II.

Portions of the DSWTP and all other alternatives (See the **Transmission Systems Engineering** section for a discussion of this proposal and alternative transmission lines under consideration) would travel through irrigated, productive farming areas. However, the available documentation does not specify the amount of Prime and other Important Farmland that would be affected (see BLM/IID pp. 3.7-32 – 3.7-39). Prime and other Important Farmlands impacted by the project could be crossed by transmission lines with periodic transmission tower structures. It is not clear from available documentation how much Prime and other Important Farmland would be affected by the project.

Furthermore, there is no DSWTP documentation regarding the amount of prime and important farmlands impacted by the footprint of the project support towers. Staff assumes that agricultural land covered by support structure footprints and an unknown amount of land around each tower would be impacted. Staff does not have sufficient information to determine that the DSWTP would not have a significant impact on prime and important farmland.

The second major IID project alternative and its minor alternative, labeled options B and B-1, may require an amendment to the BLM's California Desert Conservation Area Plan because these alternatives would not be located entirely within a BLM-designated utility corridor. A general plan amendment and zoning variance from Imperial County would be required for alternatives B and B-1 because the transmission line structures would exceed height limitations. Alternatives B and B-1 may require a consistency review by the Imperial County ALUC. These LORS considerations for the IID project do not constitute a cumulative impact in combination with BEP II, which is entirely within the City of Blythe.

Blythe Energy Project Transmission Line

Blythe Energy, LCC is proposing construction of two electric transmission line components and a new Substation. The project would be located entirely within Riverside County, between Buck Boulevard (Buck Substation) near the City of Blythe and the Julian Hinds Substation near the community of Hayfield.

Along most of the its 67.4 mile length, the proposed Buck to Julian Hinds transmission line component would be located within a 95-foot right-of-way adjacent to and north of Southern California Edison's existing Devers-Palo Verde transmission line. A small portion of the proposed transmission line near the Blythe Airport will require a consistency review by the Riverside County ALUC and FAA.

The 6.7-mile Buck to Devers-Palo Verde transmission line component to the south would be located adjacent to an existing IID 161 kV transmission line. The proposed new Midpoint Substation for interconnection would be adjacent to Southern California Edison's existing Devers-Palo Verde 500 kV transmission line.

The LORS considerations for the Blythe Energy transmission line do not constitute a cumulative impact in combination with Blythe II, which is entirely within the City of Blythe.

Blythe Energy Plant Phase One

As discussed above under Compatibility with Existing and Planned Land Uses, concerns regarding the impact of BEP I and BEP II visual water vapor plumes and thermal plumes on air traffic safety are discussed further in the **TRAFFIC AND TRANSPORTATION** section of this FSA. It is possible that the combined impact of visual and thermal plumes from the two plants would create a cumulative effect on air traffic safety that would be greater than the separate impact of the plumes from each plant (Downs).

GROWTH INDUCING IMPACTS

The region in which the BEP II site is located is sparsely populated and exhibits fairly low growth potential compared to the rest of Riverside County. There is continued potential for tourist trade and recreation/destination traffic associated with the Colorado River; active freight rail service, and possible expansion of the Blythe Airport.

In general, power plants do not, in and of themselves, induce growth in the area where they are built. In the case of BEP II, the project may: 1) displace imported electricity, thereby not resulting in any additional electricity or growth effects in Blythe, and /or 2) send any surplus electricity outside of Blythe if there is not enough demand within Blythe. In the second instance, it is impossible to predict where the electricity will go. Therefore, an analysis of the potential for regional growth inducement would be speculative.

Under CEQA, staff need not analyze the growth-inducing effects of a project if that project is already analyzed in local planning documents, and if those documents also discuss growth targets and limits. [City of Carmel-by-the-Sea v. U.S. Dept. of Transportation 123 F.3d 1142 (9th Cir. 1997)].

The project as a whole is consistent with the City of Blythe General Plan (General Plan), for which a Final Environmental Impact Report (FEIR) has been certified. The FEIR analyzes the growth in population, jobs and housing that would be attributable to a build-out of the City of Blythe. The General Plan proposes, and the FEIR analyzes 181 acres as having Heavy Industrial development potential (Blythe 1989). Since BEP II would be an industrial use within the plan area and conforms to the General Plan's Heavy Industrial designation, any growth-inducing impacts associated with BEP II as part of the industrial build-out have been analyzed by the General Plan. Staff does not foresee any growth-inducing impacts specifically from BEP II that go beyond what has already been discussed in the General Plan or FEIR.

RESPONSE TO APPLICANT'S COMMENTS ON BEP II PRELIMINARY STAFF REPORT

Item 1: The applicant requested clarification in the setting section as to the existing condition of the project site. Staff has addressed their concern with clarifying that 200,000 cubic feet of excess soils has been placed on the site.

Item 2: The applicant requested clarification as to proposed height of the 500 kV towers on site. Staff has addressed this concern within the report stating that BEP II intends to use single circuit 500 kV towers that are approximately 125 feet tall.

Item 3: Under the heading "City of Blythe Zoning Regulations", the applicant indicated the City approved the height variance for the HRSG stacks, brine concentrator, and the 500 kV transmission tower. Staff has made the necessary corrections addressing these areas of concern.

Item 4: Under the heading "City of Blythe Zoning Regulations", the applicant indicated the City of Blythe submitted their site plan to the City of Blythe for their review, and

comments by the review committee are attached for our incorporation into our analyses. Comments related to land use were incorporated into the analysis.

Item 5: The applicant discusses the issue of the WCOP and staff's request to identify parcels intended to be fallowed. The applicant has not provided additional information as to parcels of land to be fallowed or the approach to be taken to secure lands under the WCOP criterion, therefore staff was unable to fully analyze the voluntary proposal and approach the applicant is proposing to take. Staff has proposed conditions of certification (**LAND-3**) if the applicant should proceed with implementing the WCOP.

WATER CONSERVATION OFFSET PROGRAM

The applicant considers the WCOP to be voluntary; however, the applicant would not implement the WCOP if BEP II is not developed. With the limited information that has been provided by the applicant, and the unsuccessful attempt to receive additional information as to how they plan to implement this program, staff is unable to determine whether the WCOP would have an impact on County agricultural land and conflict with any Williamson Act designated agricultural land. While the WCOP's 786 acres of irrigated agricultural lands represent only 0.7 percent of the total irrigated lands in the Palo Verde Valley agricultural district, loss of agricultural land is a regional and statewide concern. Loss of agricultural production is an incremental process, which eventually has an effect on the ability of a region to sustain agriculture and the agriculturally related service economy.

The applicant has stated its intent to implement a WCOP in exchange for project water use. The WCOP as described by the applicant (BEP II 2002a, p. 7.2-6) proposes to retire irrigated lands permanently or fallow lands on a rotating basis to reduce demand for agricultural irrigation. Acquisition of lands and/or irrigation rights would be accomplished through purchase or lease by BEP II. The WCOP would include the permanent retirement or rotational fallowing of lands within Palo Verde Irrigation District (PVID) boundaries on the Mesa or the Palo Verde Valley (BEP II 2002a, p. 7.13-3). If the land retirement option is chosen, the applicant has stated that the land to be retired would not result in a Williamson Act contract[3] violation (BEP II 2003b, pp. 12-13). This option would result in the permanent loss of prime farmland, which would be a significant impact. An estimated total of up to 786 acres would be retired (BEP II 2002a, p. 7.2-6) based on an assumed consumptive water use rate of 4.2 acre-feet per acre (BEP II 2002a, p. 7.13-3). This equates to approximately 0.7 percent of total irrigated farmland in the PVID.

If the WCOP utilizes full or partial rotational fallowing, the amount of land in the WCOP could be greater in order to allow for the necessary transition of acreage at any one time. If the applicant proceeds with the WCOP option of retiring land from irrigated production, **Land-3** would require the applicant to mitigate for the loss of prime agricultural land by means of a mitigation fee to the City of Blythe or Riverside County

[3] The California Land Conservation Act, also known as the Williamson Act, allows owners of agricultural land to have their properties assessed for tax purposes on the basis of agricultural production rather than the current market value in exchange for contractual acceptance of restriction of use to agricultural and compatible uses. Individual counties and cities administer this program. Contracts run for 10 to 20 years, depending on the administering entity.

agricultural land trust or securing the acquisition of agricultural easements. On a general basis, staff believes that there would not be a significant impact if the rotational land fallowing option is chosen. The land would not be permanently converted to non-agricultural uses under this option.

Much of the lands on the Mesa that are in agricultural production are citrus orchards. Citrus represents one of the highest value crops in the area (7.43 percent of the total 2001 value) but represents only 2.53 percent of the total 2001 acreage in the Palo Verde Valley agriculture district. The investment required to get a citrus orchard to the production stage is substantial (Rethswitch). Retirement of currently active citrus producing lands could be a substantial economic impact to agriculture in the area. Citrus crops are among the highest value crops in the area, comprising approximately 3 percent of the harvested acreage in the agricultural district but contributing approximately 7 percent to the gross crop value (See Agricultural Commissioner reference for acreage and value summary).

Because specific lands for retirement or rational fallowing have not been identified, it is not known if this program would have a significant adverse impact on Prime Farmland or Farmland of Statewide Importance, as shown on the Department of Conservation (DOC) Important Farmland Map for eastern Riverside County. Similarly, the potential impact on any Williamson Act contract lands is unknown at this time. The applicant has stated that Prime Farmlands, Farmlands of Statewide Importance[4], and lands included in a Williamson Act Preserve would not be included in the WCOP (BEP II 2002a, p. 7.2-8). However, if this were to be the case, staff is unclear as to how the WCOP would conserve water, since irrigated farmland in the Palo Verde valley area is typically classified as the above Important Farmland Map categories, and is often under Williamson Act contract. (See **SOILS AND WATER** section for additional discussion on potential water impacts).

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the population of people of color is greater than fifty percent within a six-mile radius of the proposed BEP II power plant (please refer to **Socioeconomics Figure 1** in this Staff Assessment), and the low-income population is less than fifty percent within the same radius. Based on the land use analysis, staff has determined that all significant direct or cumulative impacts resulting from the construction or operation of the project will be mitigated, 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.

[4] Farmland of Statewide Importance is similar to Prime Farmland but with minor shortcomings, such as greater slope or less capacity to hold and store moisture. Lands of Statewide Importance must have been in production of irrigated crops at some time during the update cycles prior to the mapping date.

Closure of a facility like BEP II can be temporary or permanent. Temporary closure is defined as a shutdown for a period exceeding the time required for normal maintenance, including for overhaul or replacement of the combustion turbines. Causes for temporary closure include a disruption in the supply of natural gas or damage to the plant from earthquake, fire, storm, or other natural acts. Permanent closure is defined as a cessation in operation with no intent to restart operations because of plant age, damage to the plant beyond repair, economic conditions, or other reasons.

For a temporary closure where there is no release of hazardous materials, security of the facility will be maintained on a 24-hour basis, and the Energy Commission and other responsible agencies will be notified. Depending on the length of shutdown necessary, a contingency plan for the temporary cessation of operations will be implemented.

The planned lifetime of BEP II is estimated at 30 years. However, if the generation facility were still economically viable, it could be operated longer. It is also possible that the facility could become economically noncompetitive earlier than 30 years, forcing early decommissioning. Whenever the facility is to be closed permanently, the closure procedure will follow a plan that is subject to Energy Commission review and approval.

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. At the time of permanent closure, all applicable LORS would be identified and the closure plan would discuss conformance of decommissioning activities with these LORS.

The information provided in the AFC did not specifically address the effects of project closure on land use issues and concerns. 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 BEP II.

CONCLUSIONS AND RECOMMENDATIONS

1. The project is consistent with the City's General Plan and generally consistent with the City's zoning. However, the project exceeded the City's 34-foot height restriction in the Heavy Industrial Zone. As discussed earlier in this report, the City's Planning Department approved the variance request.

2. As indicated in the analysis, the City unanimously approved Resolution No. 04-897 overriding the negative advisory vote of the ALUC. Staff concurs with the ALUC

that the project is in violation of the CLUP. If the Energy Commission certifies the project the ALUC recommended mitigating conditions for land use issues. However, the ALUC stated that even with the implementation of these conditions, the project would still be inconsistent with the CLUP, specifically the requirement that the storage or distribution of explosives or flammable materials is prohibited in the ERC zone. Staff has proposed condition **LAND-4** to satisfy this mitigation requirement. Furthermore, the argument to override the ALUC recommendation is not persuasive because City staff did not discuss the cumulative benefits of alternate sites. It is staff's opinion that the City based their decision in part on a "Findings" determination that "the BEP II will not create adverse environmental impacts (e.g., noise, cultural, biological, air pollution) for the Blythe Airport or the Palo Verde Valley." Since the environmental review for BEP II is still underway, a determination has not yet been made on the environmental effects of the project to the Blythe Airport and the Palo Verde Valley.

3. The potential for visual water vapor plumes and thermal plumes caused by the project and their effect to air safety are discussed further in the **TRAFFIC AND TRANSPORTATION** section of the FSA.

4. If implemented, the WCOP has the potential to cause significant adverse impacts to agricultural resources in the area and therefore could be in conflict with County and City goals and policies that encourage retention of agricultural land. The WCOP would affect agricultural land or land that can be used for agriculture, either on the Mesa or in the Palo Verde Valley. Condition of certification **LAND-3** is recommended to address these concerns, and will reduce the potential impacts of the loss of prime agricultural land to less than significant.

PROPOSED CONDITIONS OF CERTIFICATION

If the Energy Commission certifies BEP II, staff recommends that the Commission adopt the following proposed conditions of certification:

LAND-1 The project owner shall prepare a site development plan that complies with the applicable design criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance. The site development plan must contain the following features:

- Setbacks (i.e. yard area requirements) for structures;
- Building elevations;
- Landscaping requirements;
- Temporary and permanent signs for project identification; permanent and construction phase signs; and
- Permanent parking lot design, showing the quantity and dimension of spaces.

Following preparation of the above site development plan, the project owner shall design and construct the project consistent with the applicable design

criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance.

Verification: At least 60 days prior to the start of construction, the project owner shall concurrently submit the site development plan to the CPM and the City of Blythe. The material submitted to the CPM must include documentation that the City of Blythe has been given the opportunity to review and comment on the plan and its compliance or conformance with the above-referenced requirements.

LAND-2 The project owner shall provide descriptions of the final laydown/staging areas identified for project construction to the Director of the City of Blythe Development Services Department for review and comment, and the CPM for review and approval. 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).

Verification: The project owner shall provide the specified documents to the CPM at least 30 days prior to the start of any ground disturbance activities.

LAND-3 If the WCOP involves permanent transfer of irrigation water previously used for productive irrigated farmland, the project owner shall mitigate at a one-to-one acre ratio for the conversion of productive farmland in the fulfillment of the WCOP through permanent retirement (time of the expected life of the project or greater) by implementing one or more of the following strategies:

1) a mitigation fee payment to the Riverside County agricultural land trust or the American Farmland Trust consistent with a prepared Farmlands Mitigation Agreement. The payment amount shall be determined by contacting the local assessor's office to determine the assessed value for the acreage of productive agricultural land retired by the WCOP, or by a real estate appraiser selected by the project owner and approved by the CPM.

2) securing the acquisition of an agricultural easement for other farmland (retired or fallow land that has been actively irrigated within the past five years within the Palo Verde Irrigation District Service area). Farmlands shall include areas of row crops and non-citrus producing orchards that depend upon Colorado River groundwater. Easements for irrigated farmland would be acquired based on the California Department of Conservation's Important Farmland Classification Map, but in no case shall be less than a 1:1 ratio. The program will involve approximately 726

acres assuming an accounting basis of consumptive water use of 4.2 acre-feet per acre.

Verification: Thirty (30) days prior to start of construction, 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 the same acreage of productive farmland as retired by the WCOP and/or easements within one year of start of construction as compensation for the acreage of productive farmland to be converted by the WCOP.

LAND-4 The project owner shall comply with the Riverside County Airport Land Use Commission conditions related to land use conveyance of an avigation easement to the Blythe Airport for all portions of the project including offsite power lines and pipelines within the Airport Influence Area.

Verification: At least 60 days prior to the start of construction of the power plant or any other facilities associated with the project, the project owner shall submit to the CPM a copy of the avigation easement showing proof of recordation with the Riverside County Recorder.

LAND-5 The project owner shall obtain the necessary approval(s) from the City and complete any lot merger or lot line adjustments necessary to ensure that the proposed project, including associated facilities and improvements, but excluding linear facilities, will be located on a single legal lot and owned by one entity. The BEP II facilities shall be constructed substantially as shown on the drawings submitted to and approved by the City of Blythe. It shall remain a single lot for the life of the power plant.

Verification: At least 30 days prior to the start of construction, the Project Owner shall provide the CPM with proof of completion of the above adjustments or satisfactory evidence that no such adjustments are necessary. Prior to submitting an application to the City, the project owner shall submit the proposed lot configuration to the CPM for review and approval.

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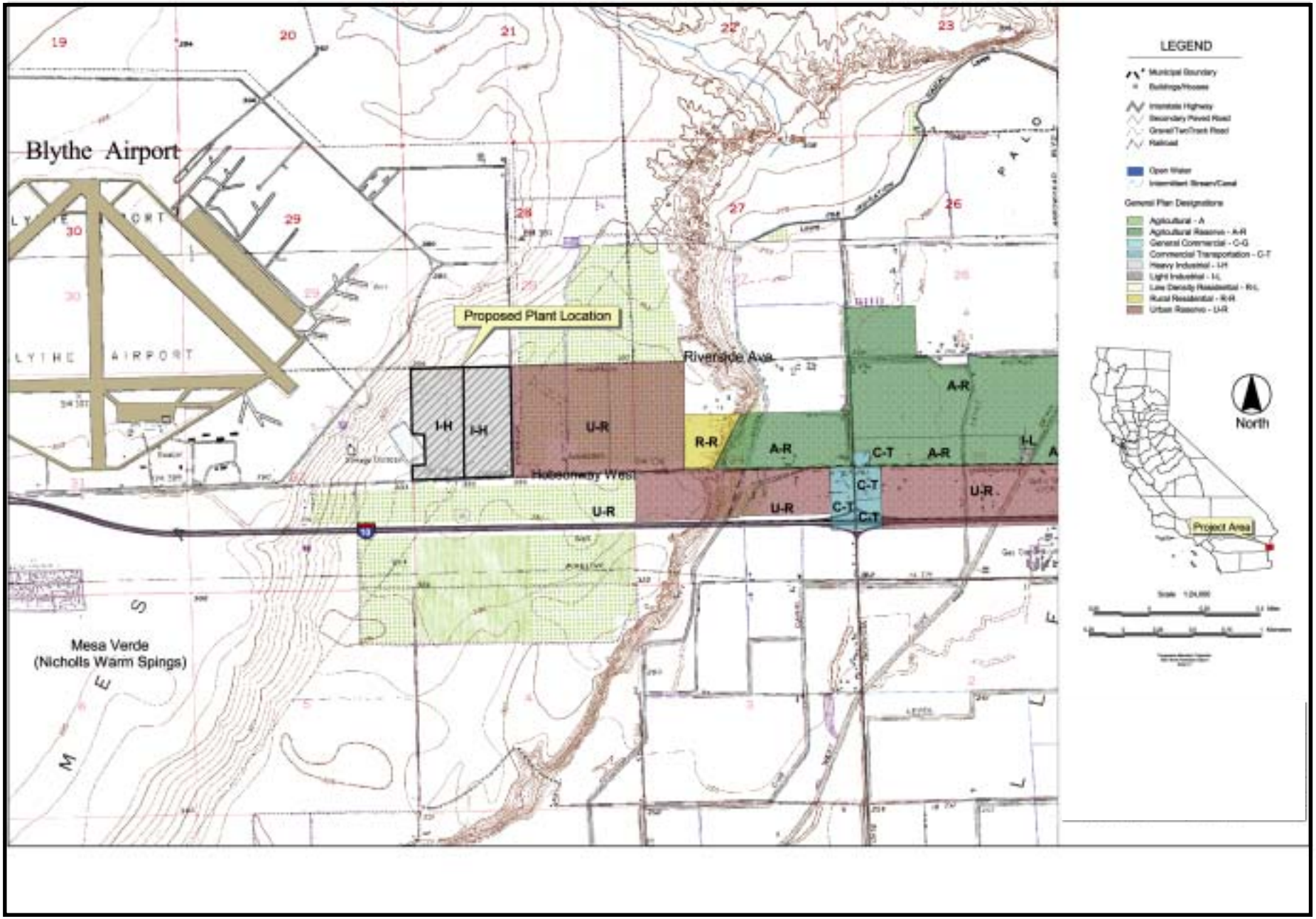
Wolfe, Pat. 2003b. Letter to Steve Munro, staff, California Energy Commission. June 20, 2003.

LAND USE - FIGURE 1

Blythe Energy Project Phase II - City of Blythe General Plan Designations

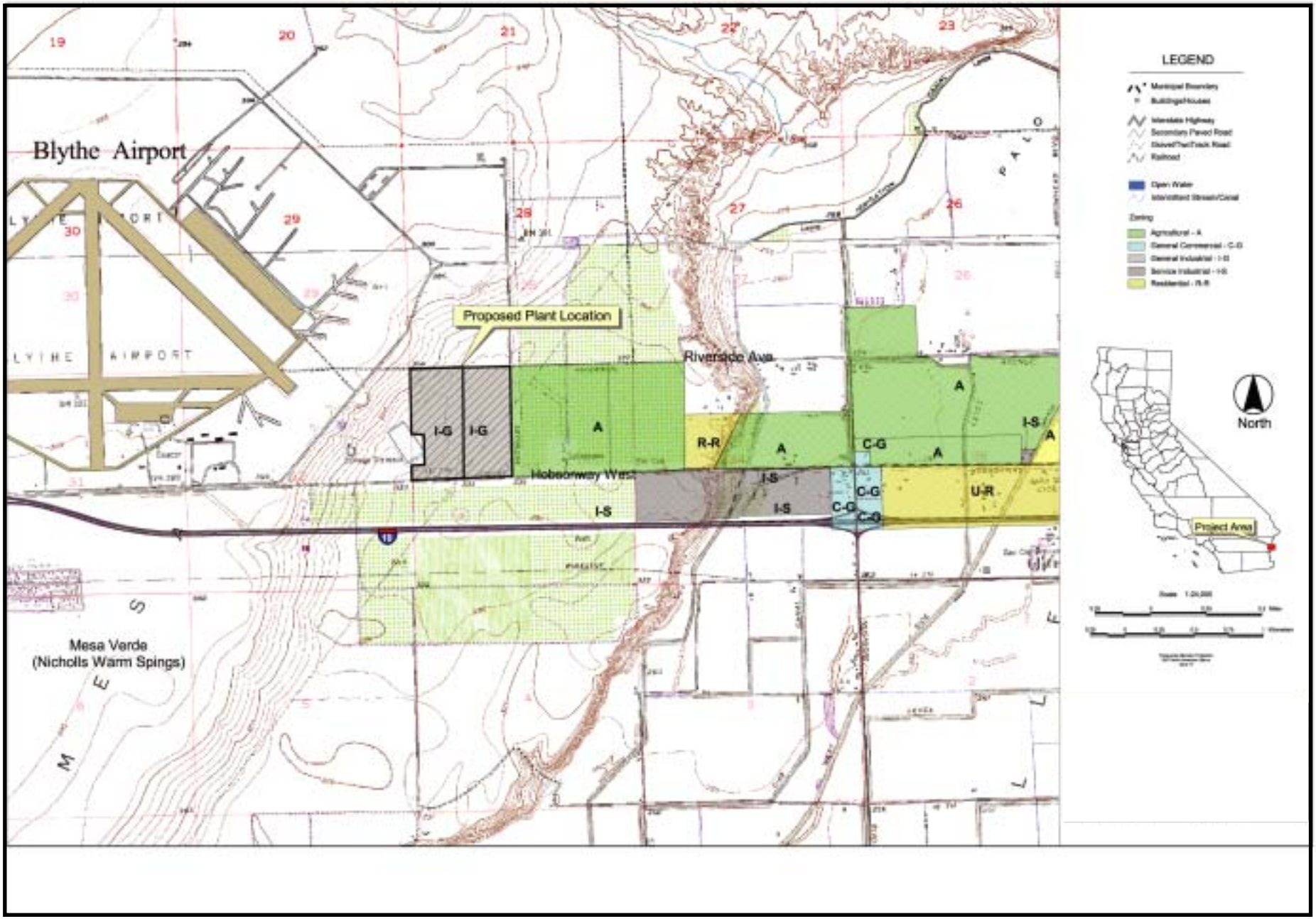


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: BEP II 2002a, Figure 7.2-1

LAND USE - FIGURE 2

Blythe Energy Project Phase II - City of Blythe Zoning

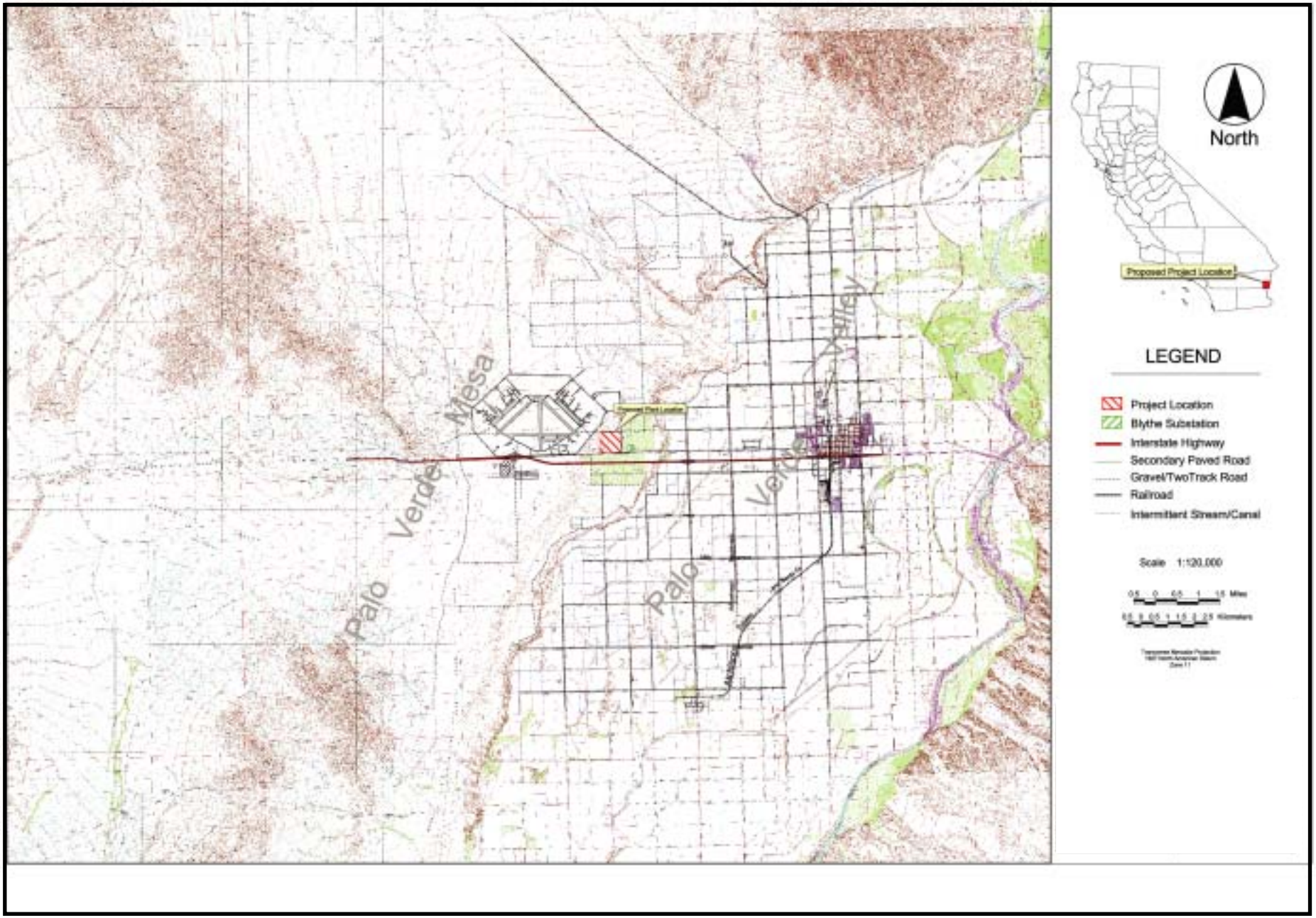


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: BEP II 2002a, Figure 7.2-2

LAND USE - FIGURE 3

Blythe Energy Project Phase II - Regional Location of the Proposed Project

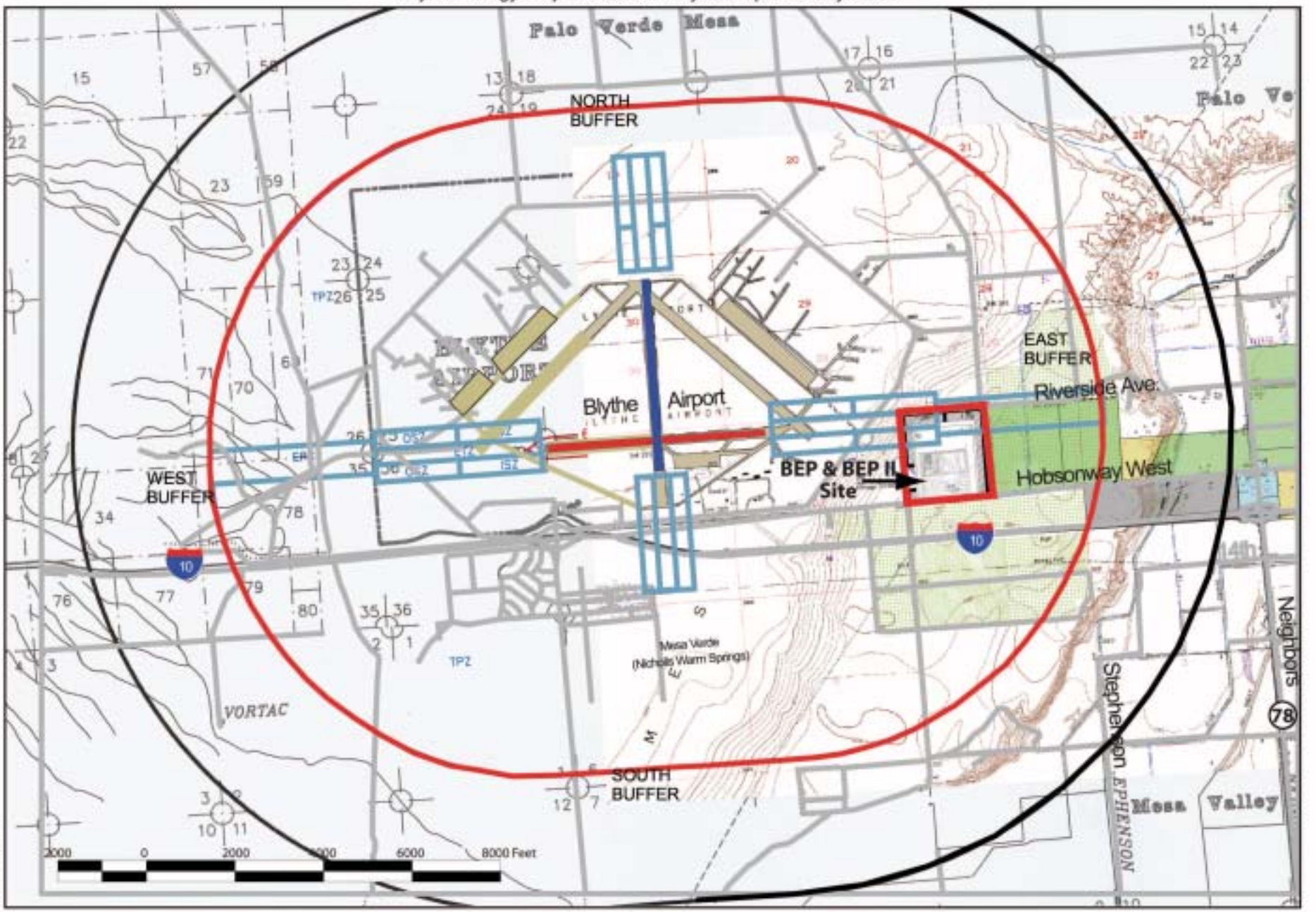


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: BEP II 2002a, Figure 2.0-1

LAND USE - FIGURE 4

Blythe Energy Project Phase II - Blythe Airport Safety Zones



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCES: BEP II 2002a - Figure 7.2-2, BEP II 2002b - Figure 36-1, Coffman - Exhibit 7a

NOISE AND VIBRATION

Testimony of Jim Buntin

INTRODUCTION

The construction and operation of any power plant creates noise or unwanted sound. The character and loudness of this noise, the times of day or night that it is produced, and the proximity of the facility to sensitive receptors combine to determine whether the facility would meet applicable noise control laws and ordinances, and whether it would cause significant adverse environmental impacts. In some cases, vibration may be produced as a result of power plant construction practices, such as pile driving. The ground-borne energy of vibration has the potential to cause structural damage and annoyance.

The purpose of this analysis is to identify and examine the likely noise and vibration impacts from the construction and operation of the Blythe Energy Project Phase II (BEP II), and to recommend procedures to ensure that the resulting noise and vibration impacts would be adequately mitigated, and would comply with applicable laws, ordinances, regulations, and standards (LORS).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

FEDERAL

Under the Occupational Safety and Health Act of 1970 (OSHA) (29 U.S.C. § 651 et seq.), the Department of Labor, Occupational Safety and Health Administration (OSHA) has adopted regulations (29 C.F.R. § 1910.95) designed to protect workers against the effects of occupational noise exposure. These regulations list permissible noise exposure levels as a function of the amount of time to which the worker is exposed (see **Noise Appendix A, Table A4** immediately following this section). The regulations further specify a hearing conservation program that involves monitoring the noise to which workers are exposed, assuring that workers are made aware of overexposure to noise, and periodically testing the workers' hearing to detect any degradation.

There are no federal laws governing off-site (community) noise.

The Federal Transit Administration (FTA) has published guidelines for assessing the impacts of ground-borne vibration associated with construction of rail projects, which have been applied by other jurisdictions to other types of projects. The FTA-recommended vibration standards are expressed in terms of the "vibration level," which is calculated from the peak particle velocity measured from ground-borne vibration. The FTA measure of the threshold of vibration perception is 65 decibels (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 & Vibration Table 1**. Refer to **Noise Appendix A** for definitions of the terms used in this table and subsequent sections.

Noise & Vibration Table 1 - Land Use Compatibility for Community Noise Environment

LAND USE CATEGORY	COMMUNITY NOISE EXPOSURE - Ldn or CNEL (db)													
	50		55		60		65		70		75		80	
Residential - Low Density Single Family, Duplex, Mobile Home														
Residential - Multi-Family														
Transient Lodging – Motel, Hotel														
Schools, Libraries, Churches, Hospitals, Nursing Homes														
Auditorium, Concert Hall, Amphitheaters														
Sports Arena, Outdoor Spectator Sports														
Playgrounds, Neighborhood Parks														
Golf Courses, Riding Stables, Water Recreation, Cemeteries														
Office Buildings, Business Commercial and Professional														
Industrial, Manufacturing, Utilities, Agriculture														

	Normally Acceptable	Specified land use is satisfactory, based upon the assumption that any buildings involved are of normal conventional construction, without any special noise insulation requirements.
	Conditionally Acceptable	New construction or development should be undertaken only after a detailed analysis of the noise reduction requirements is made and needed noise insulation features are included in the design.
	Normally Unacceptable	New construction or development should be discouraged. If new construction or development does proceed, a detailed analysis of the noise reduction requirement must be made and needed noise insulation features included in the design.
	Clearly Unacceptable	New construction or development generally should not be undertaken.

Source: State of California General Plan Guidelines, Office of Planning and Research, June 1990.

The State of California, Office of Noise Control, prepared a Model Community Noise Control Ordinance, which provides guidance for acceptable noise levels in the absence of local noise standards. The Model also contains a definition of a simple tone, or "pure tone," in terms of one-third octave band sound pressure levels that can be used to determine whether a noise source contains annoying tonal components. The Model Community Noise Control Ordinance further recommends that, when a pure tone is present, the applicable noise standard should be lowered (made more stringent) by 5 dBA.

Other State LORS include the California Occupational Safety and Health Administration (Cal-OSHA) regulations.

California Environmental Quality Act

CEQA requires that significant environmental impacts be identified, and that such impacts be eliminated or mitigated to the extent feasible. Section XI of Appendix G of CEQA Guidelines (Cal. Code Regs., tit. 14, App. G) sets forth some characteristics that may signify a potentially significant impact. Specifically, a significant effect from noise may exist if a project would result in:

a) exposure of persons to, or generation of, noise levels in excess of standards established in the local General Plan or noise ordinance, or applicable standards of other agencies;

b) exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels;

c) a substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project; or

d) a substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project.

The Energy Commission staff, in applying Item c) above to the analysis of this and other projects, has concluded that a potential for a significant noise impact exists where the noise of the project plus the background exceeds the background by 5 dBA L_{90} or more at the nearest noise 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];

[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.

2. the duration and frequency of the noise;
3. the number of people affected; and
4. the land use designation of the affected receptor sites.

Staff usually considers noise due to construction activities to be insignificant if:

1. The construction activity is temporary,
2. Use of heavy equipment and noisy activities is limited to daytime hours, and
3. All feasible noise abatement measures are implemented for noise-producing equipment.

Cal-OSHA

Cal-OSHA has promulgated Occupational Noise Exposure Regulations (Cal. Code Regs., tit. 8, §§ 5095-5099) that set employee noise exposure limits. These standards are equivalent to the federal OSHA standards (see **Noise Appendix A, Table A4**).

LOCAL

Riverside County General Plan Noise Element

The Noise Element of the Riverside County General Plan contains standards, policies and procedures that are intended to minimize noise impacts to the community. The noise level standards for new projects, including non-transportation noise sources, employ the Community Noise Equivalent Level (CNEL) or Day-Night Level (Ldn), and are similar to those shown by **Noise and Vibration Table 1**. Specifically, the County Noise Element standards for residential land uses are: Normally Acceptable: CNEL or Ldn up to 60 dB; Conditionally Acceptable: up to 70 dB CNEL or Ldn.

Riverside County Code

Riverside County has adopted restrictions affecting construction noise sources in Chapter 15.04 of the Riverside County Code. Construction within one-quarter mile of an occupied residence is prohibited between the hours of 6 p.m. and 6 a.m., except as allowed with the written consent of the building official.

City of Blythe General Plan Noise Element

The City of Blythe is currently applying a draft Noise Element of the General Plan; the draft provided to Energy Commission staff in March 2002 (affirmed in September 2003) applies noise standards using a table similar to **Noise & Vibration Table 1**. The draft policy for new development of industrial or other noise-generating land uses prohibits development if resulting noise levels would exceed 60 dB Ldn or CNEL at the boundary of areas containing or planned and zoned for residential or other noise-sensitive land uses.

SETTING

PROJECT BACKGROUND

The BEP II project involves the construction and operation of a nominal 520-megawatt (MW) combined cycle power plant, which is proposed to be adjacent to the existing Blythe Energy Project (BEP I) described by 99-AFC-8, in the City of Blythe. The project is comprised of two natural gas combustion turbines with electrical inlet chillers or evaporative inlet air coolers, two heat recovery steam generators, and a condensing steam turbine. Mechanical draft cooling towers would be employed. As stated in the AFC, the BEP II would be connected to the Buck Blvd. substation. At this time, it is not clear how BEP II will ultimately connect to the grid. The BEP II would connect to the BEP I natural gas supply line.

The equipment that has the greatest potential to generate significant noise levels includes the gas and steam turbines, steam generators, pumps, motors, main transformers, and the mechanical draft evaporative cooling towers.

Power Plant Site

This site is located within the City of Blythe. Land uses in the project vicinity include agricultural, industrial (BEP I), and residential uses.

The BEP II would be constructed on currently vacant land west of the BEP I power plant site. The nearest noise sensitive use is a home at 16531 Hobsonway, about 2,728 feet from the site boundary. This residence is located outside of the Blythe city limits, in Riverside County.

Linear Facilities

The AFC states that the BEP II would connect with the Western electrical transmission system via the existing Devers substation, which will require a 118-mile off-site transmission line. The transmission line would be part of the proposed Imperial Irrigation District Desert Southwest Transmission Project. At this time, it is not clear how BEP II will ultimately connect to the grid.

EXISTING NOISE LEVELS

In order to predict the likely noise effects of the project on adjacent sensitive receptors, the applicant commissioned two ambient noise surveys in the area (BEP II 2002a and BEP II 2004e). The first survey was conducted November 2-3, 1999 as part of the environmental study for the BEP I AFC (99-AFC-8). The noise survey was conducted using a Metrosonics dB308 data logger meeting the requirements of the American National Standards Institute (ANSI) for Type 1 sound level measurement systems. The applicant's noise survey monitored existing noise levels at the commercial/industrial building at 16275 Hobsonway, which is about 1,425 feet from the project boundary, and about 600 feet north of I-10. The nearest house is located farther from the project boundary, and closer to I-10, than the measurement site.

Noise & Vibration Table 2 summarizes the ambient noise measurement results (BEP II 2002d).

Noise & Vibration Table 2 - Measured Noise Levels at 16275 Hobsonway: November 2-3, 1999

Time of Day	Noise Level, dBA			
	Leq	L10*	L50*	L90*
1400	51.3	55	50	44
1500	51.0	54	49	44
1600	52.3	56	51	46
1700	56.5	59	55	51
1800	56.5	59	56	52
1900	58.2	61	57	52
2000	58.5	62	58	53
2100	56.6	60	55	50
2200	55.2	58	54	50
2300	52.7	55	52	49
0000	57.4	62	56	50
0100	55.9	60	54	48
0200	55.4	59	54	49
0300	54.5	58	53	48
0400	54.7	59	52	45
0500	57.3	61	55	49
0600	56.0	59	54	49
0700	53.3	57	52	47
0800	52.9	57	51	45
0900	50.6	54	49	44
1000	50.6	54	49	44
1100	49.4	52	48	43
1200	48.0	51	47	42
1300	51.4	55	50	44
1400	51.0	54	50	45
25-hr. average	54.8	57	52	47

* See Noise Table A1 for definitions of these terms.

The calculated Ldn was 61.9 dB, and the calculated CNEL was 62.3 dB. In general, the environment in the immediate vicinity of the project site could be described as relatively quiet. The dominant background noise source was traffic on I-10, and the quietest period of the 24-hour day was during daytime hours (8 a.m. to 3 p.m.). The quietest period was also a period with low wind velocities. The average L90 during the quietest contiguous 4-hour period of the day was 43 dBA.

The second ambient noise survey was conducted over two periods in December 2003 and January 2004. This survey was performed at the nearest residence, at 16531 West Hobsonway.

During the noise measurements on January 19-21, 2004, the BEP I facility was not in operation. The lowest average background noise level over any four-hour period during that sample was 46 dBA (L90). During the noise measurements on December 19-23, 2003, BEP I was in operation, and the lowest average background noise level over any

four-hour period was 47 dBA (L90). The operation of BEP I therefore does not appear to cause a significant change in ambient noise levels at the nearest residence. The dominant background noise source at this residence was traffic on I-10. Since the residence is closer to I-10 than the measurement site employed in 1999, the background noise levels at the residence are slightly higher than at the 1999 measurement site.

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. Sensitive receptors near the plant site could be affected by noise from these activities. 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. Riverside County regulates the permissible hours of construction, but does not have any specific noise limits during those hours.

The applicant has prepared an analysis of construction noise impacts, listing predicted noise levels due to specific types of equipment and of generalized construction activities (BEP II 2002d). No pile driving would be required (BEP II 2002g). The construction noise analysis for the worst-case noise sources indicated that the maximum noise level predicted at the nearest residence would be about 56 dBA, including ambient noise. The applicant opined that, since this level of noise is close to the maximum average noise level at the nearest residence, the construction noise would likely be audible during traffic lull periods.

There are no other noise-sensitive receptors within the range of distances where construction noise would be expected to be audible.

The changes in ambient noise levels would be of a temporary nature. The unmitigated increases in ambient noise levels due to construction are expected to be insignificant.

Based upon the potential noise impacts of construction, the Energy Commission staff recommends 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 would be limited by the proposed Condition of Certification **NOISE-8**, and would be of limited duration, potential construction noise impacts to receptors in the BEP II project area are considered to be less than significant.

Steam Blows

Typically, the steam blows during construction and start-up create the loudest noise encountered during the construction phase. Steam blows are necessary after erection and assembly of the feedwater and steam systems because the piping and tubing that comprises the steam path accumulate dirt, rust, scale, and construction debris such as weld spatter, dropped welding rods, and the like. If the plant were to start up without thoroughly cleaning out the piping and tubing, all this debris would find its way into the steam turbine, quickly destroying the machine.

To prevent this damage, before the steam system is connected to the turbine, the steam line is temporarily routed to the atmosphere. High-pressure steam is then raised in the heat recovery steam generator (HRSG) or a temporary boiler and allowed to escape to the atmosphere through the steam piping. This flushing action, referred to as a steam blow, effectively cleans out the steam system. A series of short steam blows, lasting two or three minutes each, is performed several times daily over a period of two or three weeks. At the end of this procedure, the steam line is connected to the steam turbine, which is then ready for operation.

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 daytime 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, a low-pressure high velocity cleaning method has been considered that would produce noise levels ranging from 75 to 80 dBA at 100 feet from the outlet, or about 39 to 44 dBA at the nearest residence, after accounting for atmospheric absorption (BEP II 2002g). The resulting noise levels would be below ambient noise levels. The predicted low-pressure steam blow noise levels would not interfere with speech outdoors.

It appears that the applicant plans to use the high-pressure steam blow process. The applicant notes that no noise complaints have been received for BEP I (BEP II 2004e). Energy Commission staff has proposed Condition of Certification **NOISE-4** to mitigate steam blow noise levels.

Energy Commission staff further proposes a notification process to make neighbors aware of scheduled steam blows (see proposed Condition of Certification **NOISE-5** below).

Linear Facilities

A new natural gas line would be installed from the project site to the existing line serving the BEP I.

Trenching for the proposed pipeline would involve use of diesel-powered equipment. Noise produced by this equipment could be annoying to nearby residents. To ensure that trench construction noise would not be significant, staff has recommended Condition of Certification **NOISE-8**.

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 (BEP II 2002a). To ensure that construction workers are, in fact, adequately protected, Energy Commission staff proposes Condition of Certification **NOISE-3**.

PROJECT SPECIFIC IMPACTS — OPERATION

Community Effects

The applicant has incorporated noise reduction measures into the design of the project. The applicant intends to achieve noise level standards that would prevent a significant noise impact as defined by staff; the allowable noise levels under LORS could be substantially higher than existing background noise levels.

Power Plant Operation

During its operating life, the BEP II represents essentially a steady, continuous noise source day and night. Occasional brief increases in noise levels would occur as steam relief valves open to vent pressure, or during startup or shutdown as the plant transitions to and from steady-state operation. At other times, such as when the plant is shut down for lack of dispatch or for maintenance, noise levels would decrease.
The primary noise sources anticipated from the 520 MW facility include the combustion turbines, steam turbine generators, relief valves, circulating water pumps, HRSG exhaust stacks, and cooling towers. The noise emitted by power plants during normal operations is generally broadband, steady state in nature (BEP II 2002g), as demonstrated by the applicant's noise level data. The resulting hourly average noise levels are typically dominated by the steady-state noise sources.

The applicant conducted noise measurements at BEP I in March 2003 (BEP II 2004e), and performed acoustical calculations to describe typical facility noise emissions. The modeling assumed that the noise levels and frequency content of BEP I would be representative of the noise produced by the BEP II. The reference noise level assumed for BEP II was 61.5 dBA at a distance of 400 feet.

Specific noise mitigation measures evaluated by the applicant (BEP II 2004e) included:

- An acoustically treated turbine hall,

- Standard power plant noise control features for HRSG units, including thermally insulated casings and inlet ductwork, but without exhaust stack silencing baffles or acoustical insulation.

Noise & Vibration Table 3 lists the predicted project noise levels at the nearest sensitive receptor in terms of the background noise level (L_{90}). The predicted noise levels include the applicant's assumptions listed above. It is assumed that the noise levels experienced at more distant receivers would be lower than those shown by **Noise & Vibration Table 3.**

The applicant has also described the potential noise effects of replacing the electrical inlet chillers with mechanical refrigeration chillers, assuming that the near-field sound pressure levels would be limited to 85 dBA (BEP II 2002f). The applicant concluded that the proposed inlet chilling equipment would not produce noise that is significantly different from the noise produced during steady-state plant operation.

Noise & Vibration Table 3 – Summary of Predicted Operational Noise Levels

Sensitive Receptor Site	Background Noise Level (L90), dBA						
	Ambient (2003-2004)*	BEP I	Ambient plus BEP I	BEP II	Cumulative	Change re: Ambient (2003-2004)	Change re: Ambient plus BEP I
16531 Hobsonway	46	40	47	45	49	+3	+2
Source: BEP II 2004e * Average of L90 values for the four quietest contiguous hours.							

The predicted BEP II power plant noise level would exceed the ambient noise level measured in 2003-2004 by about 3 dB. It would also exceed the estimated current ambient noise level (2003-2004 plus BEP I) by 2 dB.

The proposed Condition of Certification **NOISE-6** would require that the noise level produced by the BEP II plant operation not exceed 49 dBA L_{eq} at the nearest residence, which is the level predicted by the applicant's consultant. The resulting increase over ambient noise levels with and without operation of BEP I would be barely perceptible, and would not be expected to be annoying. Noise due to the BEP II operations would not exceed the standards of the LORS at any sensitive receptor.

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 would be generated during the operation of the project.

Noise levels generated during system start-up and shutdown may be elevated compared to steady-state operations, as steam relief valves may be employed for short periods under those conditions. The applicant has indicated that the duration of start-up periods could be approximately three hours (BEP II 2002g). The potentially significant noise sources during start-up would be the start-up steam system and the high-pressure steam bypass station. Based on the system design specifications, the predicted start-up steam vent noise levels would be in the range of 50 to 55 dBA at the nearest residence. The applicant's data does not describe the durations of these steam releases, but such releases are typically relatively short, in the range of a few minutes per occurrence. The predicted steam bypass station noise level would be about 39 to 44 dBA at the nearest residence; the event duration could be in the range of 30 minutes to one hour or more.

To ensure that no strong tonal noises are present and that intermittent noises are mitigated, Energy Commission staff proposes Condition of Certification **NOISE-6**, below, which requires the applicant to ensure that there are no pure tones, and to mitigate the noise from steam relief valves.

Linear Facilities

The electrical output of the plant would be connected to the Buck Blvd. substation, which is located at the northeastern corner of the BEP I site. Connections between the power plant and the substation would be contained within the BEP I and BEP II property boundaries. Since there are no sensitive receivers in proximity to these connections, no noise impacts are expected.

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 (BEP II 2002a). 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 proposes Conditions of Certification **NOISE-3** and **NOISE-7**, below.

CUMULATIVE IMPACTS

Section 15130 of the *CEQA Guidelines* (Cal. Code Regs., tit. 14) requires a discussion of cumulative environmental impacts. 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 that the BEP II could contribute to cumulative noise impacts in the project study area (BEP II 2002d), and staff agrees this is the case. To ensure that the cumulative effect of the two noise sources would be insignificant, Energy Commission staff has proposed Condition of Certification **NOISE-6**.

At this time, it is not certain how the BEP II will ultimately connect to the grid. The electrical output of the plant may be connected to the Buck Blvd. substation, which in turn would be connected to the proposed Imperial Irrigation District Desert Southwest Transmission Project transmission lines. This would be a 118-mile off-site transmission line, and its environmental noise effects are addressed by an EIR/EIS prepared by the District (BEP II 2002h). According to the draft EIR/EIS, the transmission line project could result in noise impacts due to construction, blasting, and noise due to corona discharge hum and onsite maintenance.

Construction noise impacts would be mitigated in the draft EIR/EIS by limits on the time of day for construction, and by requirements for adequate mufflers. Blasting impacts would be mitigated in the draft EIR/EIS by establishing limits on the time of day of blasting, by requiring notice to sensitive receptors when blasting is planned, and by requiring a blasting plan approved by the BLM.

Since corona discharge hum is predicted to be 44 dBA directly under the transmission lines during inclement weather, and 20 dBA in dry weather, it was not considered significant. Other operational noise such as vehicle traffic was also considered insignificant. No additional mitigation would be required.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the population of people of color is greater than fifty percent within a six-mile radius of the proposed BEP II power plant (please refer to **Socioeconomics Figure 1** in this Staff Assessment), and the low-income population is less than fifty percent within the same radius.

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, the impact would be reduced to less than significant. Therefore, there is no potential disparate impact on the minority population, and there are no noise environmental justice issues related to this project.

FACILITY CLOSURE

In the future, upon closure of the BEP II, all operational noise from the entire BEP II site would cease, and no further adverse noise impacts from operation of the BEP II 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 BEP II, 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 THE APPLICANT'S COMMENTS

The applicant submitted several comments regarding noise and vibration as described by the Preliminary Staff Assessment (BEP II2004e). Staff has reviewed those comments and incorporated appropriate revisions. The following text summarizes the staff response to comments:

Numbered Comments:

1. The incorrect reference to use of an auxiliary boiler was removed from the FSA.
2. The more recent ambient noise level measurements have been reported in the FSA.
3. The text has been revised to reflect current operation of BEP I.
4. The section dealing with steam blows has been revised.
5. NOISE-8 has been revised as requested.
6. (No comment was received with this number.)
7. The text has been revised to incorporate the more recent noise measurement data.
8. The text has been revised to incorporate the more recent noise measurement and prediction data. Staff did not agree with the applicant's proposed noise standard, relying instead upon the noise level prediction for BEP II that was supplied by the applicant's consultants. The difference is that the proposed noise standard is 2 dB lower than requested by the applicant.

Comments regarding the proposed Conditions of Certification:

NOISE-1 has been revised by eliminating the reference to linear facilities.

NOISE-2 was not revised; the recommended text is consistent with current Energy Commission practices, which have been standardized over the past 4-5 years. The revised time lines for notification are necessary to allow prompt Energy Commission response to legitimate noise complaints.

NOISE-4 has been revised to allow high-pressure steam blows.

NOISE-5 was not revised; the recommended text is consistent with current Energy Commission practices, which require that time frames be incorporated into the Verification section of the conditions of certification. This practice allows minor adjustments of time frames by Energy Commission staff as needed to respond to specific concerns, without requiring action by the Commission at a publicly noticed meeting.

NOISE-6 has been revised to reflect the more recent ambient and BEP I noise measurement data. The proposed noise standard is based upon the noise levels described by the Noise Report submitted with the comments (BEP II2004e).

NOISE-7 was not revised; the recommended text is consistent with current Energy Commission practices, which require that time frames be incorporated into the Verification section of the conditions of certification. This practice allows minor adjustments of time frames by Energy Commission staff as needed to respond to specific concerns, without requiring action by the Commission at a publicly noticed meeting.

NOISE-8 has been revised as requested by the applicant, except that the citation to the Riverside County Ordinance section was updated.

CONCLUSIONS AND RECOMMENDATIONS

Energy Commission staff concludes that BEP II, with the recommended mitigation, could be built and operated to comply with all applicable noise laws, ordinances, regulations, and standards. Energy Commission staff further concludes that if the BEP II facility were designed as described above, and further mitigated as described below in the proposed Conditions of Certification, it would not be expected to produce significant adverse noise impacts. The following proposed Conditions of Certification will ensure compliance with all applicable noise LORS, and ensure that the project would not result in a significant increase in ambient noise levels.

PROPOSED CONDITIONS OF CERTIFICATION

NOISE-1 At least 15 days prior to the start of project related ground disturbance, the project owner shall notify by mail all residents within one-half mile of the site 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: Prior to ground disturbance, the project owner shall transmit to the CPM 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 (below), 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 business days of receiving a noise complaint, the project owner shall file with the City of Blythe Development Services Department, the Riverside County Planning Department, and the CPM a copy of the Noise Complaint Resolution Form, documenting the resolution of the complaint. If mitigation is required to resolve a complaint, and the complaint is not resolved within a 3-business day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is implemented.

NOISE-3 The project owner shall submit to the CPM for review and approval an employee construction noise exposure control program. The noise control program shall be used to reduce employee exposure to high noise levels during construction and also to comply with applicable OSHA and Cal-OSHA standards.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall submit to the CPM the noise control program. The project owner shall make the program available to Cal-OSHA upon request.

NOISE-4 If a traditional high-pressure steam blow process is employed during construction, the project owner shall equip steam blow piping with a temporary silencer that quiets the noise of steam blows to no greater than 100 dBA measured at a distance of 100 feet. The project owner shall conduct steam blows only between the hours of 8 a.m. to 5 p.m., unless the CPM agrees to longer hours based on a demonstration by the project owner that offsite noise impacts will not cause annoyance. If a low-pressure continuous steam blow process is employed, the project owner shall submit a description of this process, with expected noise levels and projected hours of operation, to 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 blow(s), the project owner shall notify all residents or business owners within one mile of the site of the planned steam blow activity, and shall make the notification available to other area residents in an appropriate manner.
The notification may be in the form of letters to the area residences, telephone calls, fliers or other effective means. The notification shall include a description of the purpose and nature of the steam blow(s), the proposed schedule, the expected sound levels, and the explanation that it is a one-time operation and not a part of normal plant operations.

Verification: The project owner shall notify residents and businesses at least 15 days prior to the first 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 noise level (L_{eq}) of more than 49 dBA, measured at any residence.

No new pure tone components may be introduced. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints. Steam relief valves shall be adequately muffled to preclude noise that draws legitimate complaints.

A. Within 30 days of the project first achieving a sustained output of 80 percent or greater of rated capacity, the project owner shall conduct a 25-hour community noise survey at or near the residence at 16531 Hobsonway. The noise survey shall also include short-term measurement of one-third octave band sound pressure levels to ensure that no new pure-tone noise components have been introduced.

B. If the results from the noise survey indicate that the noise level due to the plant operations exceeds the noise standard listed above for any given hour during the 25-hour period, mitigation measures shall be implemented to reduce noise to a level of compliance with these limits.

C. If the results from the noise survey indicates that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

Verification: Within 30 days after completing the community noise survey, the project owner shall submit a summary report of the survey to the City of Blythe Development Services Department, to the Riverside County Planning Department, and to the CPM. Included in the post-construction survey report will be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limits, and a schedule, subject to CPM approval, for implementing these measures. Within 30 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 measures that will be employed to comply with the applicable California and federal regulations.

Verification: Within 30 days after completing the survey, the project owner shall submit the noise survey report to the CPM. The project owner shall make the report available to OSHA and Cal-OSHA upon request.

NOISE-8 Noisy construction or demolition work (that which causes off-site annoyance, as evidenced by the filing of a legitimate noise complaint) shall be restricted to the times of day delineated below:
High-pressure steam blows 8 a.m. to 5 p.m.

Other noisy work::

According to City of Blythe regulations and Riverside County Ordinance Chapter 15.04

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.

EXHIBIT 1 - NOISE COMPLAINT RESOLUTION FORM

Blythe Energy Project II
(02-AFC-1)

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 Riverside. Noise Element of the Sacramento County General Plan.

County of Riverside. Chapter 15.04 of the Riverside County Code.

City of Blythe. 2003. Draft Noise Element of the City of Blythe General Plan.

Federal Transit Administration. 1995. *Transit Noise and Vibration Impact Assessment*. DOT-T-95-16. Harris, Miller, Miller and Hanson, Inc. Burlington, Massachusetts.

State of California. 1990. General Plan Guidelines, Office of Planning and Research, June 1990.

State of California. 1977. Model Community Noise Control Ordinance, Office of Noise Control, April 1977.

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BEP II (Blythe Energy Project Phase II). 2003h. Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR). 03/25/2003 (tn: 29717)

BEP II (Blythe Energy Project Phase II). 2004e. Caithness Blythe II Responses to the Blythe II Phase II Preliminary Staff Assessment. 04/28/2004. (tn: 31327)

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 (Effects of Noise on People, U.S. Environmental Protection Agency, December 31, 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: Guidelines for the Preparation and Content of Noise Elements of the General Plan, Model Community Noise Control Ordinance, California Department of Health Services 1976, 1977.

Noise Table A2 Typical Environmental and Industry Sound Levels			
Noise Source (at distance)	A-Weighted Sound Level in Decibels (dBA)	Noise Environment	Subjective Impression
Civil Defense Siren (100')	140-130		Pain Threshold
Jet Takeoff (200')	120		Very Loud
Very Loud Music	110	Rock Music Concert	
Pile Driver (50')	100		
Ambulance Siren (100')	90	Boiler Room	
Freight Cars (50')	85		
Pneumatic Drill (50')	80	Printing Press Kitchen with Garbage Disposal Running	Loud
Freeway (100')	70		Moderately Loud
Vacuum Cleaner (100')	60	Data Processing Center Department Store/Office	
Light Traffic (100')	50	Private Business Office	
Large Transformer (200')	40		Quiet
Soft Whisper (5')	30	Quiet Bedroom	
	20	Recording Studio	
	10		Threshold of Hearing

Source: Handbook of Noise Measurement, Arnold P.G. Peterson, 1980

SUBJECTIVE RESPONSE TO NOISE

The adverse effects of noise on people can be classified into three general categories:

- Subjective effects of annoyance, nuisance, dissatisfaction.
- Interference with activities such as speech, sleep, and learning.
- Physiological effects such as anxiety or hearing loss.

The sound levels associated with environmental noise, in almost every case, produce effects only in the first two categories. Workers in industrial plants can experience noise effects in the last category. There is no completely satisfactory way to measure the subjective effects of noise, or of the corresponding reactions of annoyance and dissatisfaction, primarily because of the wide variation in individual tolerance of noise.

One way to determine a person's subjective reaction to a new noise is to compare the level of the existing (background) noise, to which one has become accustomed, with the level of the new noise. In general, the more the level or the tonal variations of a new noise exceed the previously existing ambient noise level or tonal quality, the less acceptable the new noise will be, as judged by the exposed individual.

With regard to increases in A-weighted noise levels, knowledge of the following relationships (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: Architectural Acoustics, M. David Egan, 1988

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 C.F.R. § 1910.95

PUBLIC HEALTH

Testimony of Ramesh Sundareswaran

INTRODUCTION

The purpose of staff's public health analysis is to determine if toxic air contaminants released from the proposed Blythe Energy Project II (BEP II) will have the potential to cause significant adverse public health impacts or to violate standards for public health protection. If potentially significant health impacts are identified, staff will evaluate mitigation measures to reduce such impacts to insignificant levels.

Staff addresses potential impacts of regulated or criteria air pollutants in the **Air Quality** section (please see **Public Health** Attachment A for a discussion of the health effects of criteria pollutants). Impacts on public and worker health from accidental releases of hazardous materials are examined in the **Hazardous Materials Management** section. Health effects from electromagnetic fields are discussed in the **Transmission Line Safety and Nuisance** section. Pollutants released from the project in wastewater streams are discussed in the **Soils and Water Resources** section. Past spills that may have occurred at the site are described in the **Waste Management** section.

METHOD OF ANALYSIS

Public health staff is concerned about toxic air contaminants to which the public could be exposed during project construction and routine operation. Following the release of toxic air contaminants into the air or water, people could come into contact with them through inhalation, dermal contact, or ingestion via contaminated food or water.

Air pollutants for which no air quality standards have been set are called noncriteria pollutants. Unlike criteria pollutants such as ozone, carbon monoxide, sulfur dioxide, or nitrogen dioxide, noncriteria pollutants have no state or national ambient (outdoor) air quality standards that specify levels considered safe for everyone.

Since noncriteria pollutants do not have such standards, a process known as health risk assessment is used to determine if people might be exposed to those types of pollutants at unhealthy levels. The risk assessment procedure consists of the following steps:

1. Identify the types and amounts of hazardous substances that BEP II could emit to the environment;
2. Estimate worst-case concentrations of project emissions in the environment using dispersion modeling;
3. Estimate amounts of pollutants to which people could be exposed through inhalation, ingestion, and dermal contact; and
4. Characterize potential health risks by comparing worst-case exposure to safe standards based on known health effects.

Initially, a screening level risk assessment is performed using generic assumptions that are intentionally biased toward protection of public health. That is, a study is done that is designed to overestimate or maximize public potential health impacts from exposure to project emissions. In reality, it is likely that the actual risks from the power plant will be much lower than the risks which are estimated by the assessment. This is accomplished by examining conditions that would lead to the highest, or worst-case, risks and then using those in the study. Such conditions include:

- using the highest levels of pollutants that could be emitted from the plant;
- assuming weather conditions that would lead to the highest ambient concentration of pollutants;
- using the type of air quality computer model which predicts the highest plausible impacts;
- calculating health risks at the location where the pollutant concentrations are calculated to be the highest;
- using health-based standards designed to protect the most sensitive members of the population (i.e., the young, elderly, and those with respiratory illnesses); and
- assuming that an individual's exposure to cancer-causing agents occurs for 70 years.

A screening level risk assessment will, at a minimum, include the potential health effects from inhaling hazardous substances. Some facilities may also emit certain substances which could present a health hazard from noninhalation pathways of exposure (OEHHA 2003, Tables 5.1, 6.3, 7.1). When these substances are present in facility emissions, the screening level analysis includes the following additional exposure pathways: soil ingestion, dermal (i.e., skin) exposure, and mother's milk (OEHHA 2003, p. 5-3).

The risk assessment process addresses three categories of health impacts: acute (short-term) health effects, chronic (long-term) noncancer effects, and cancer risk (also long-term).

Acute health effects result from short-term (1-hour) exposure to relatively high concentrations of pollutants. Acute effects are temporary in nature, and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic health effects are those which arise as a result of long term exposure to lower concentrations of pollutants. The exposure period is considered to be approximately from 12 to 100 percent of a lifetime, or from eight to 70 years (OEHHA 2003, p. 6-5). Chronic health effects include diseases such as emphysema and heart disease.

The analysis for noncancer health effects compares the maximum project contaminant levels to safe levels called "reference exposure levels" or RELs (OEHHA 2003, p. 6-2). RELs are amounts of toxic substances to which people can be exposed and suffer no adverse health effects. These exposure levels are designed to protect the most sensitive individuals in the population, such as infants, the aged, and people suffering from illness or disease which makes them more sensitive to the effects of toxic substance exposure. RELs are based on the most sensitive adverse health effect

reported in the medical and toxicological literature, and include margins of safety. The margin of safety addresses uncertainties associated with inconclusive scientific and technical information available at the time of standard setting and is meant to provide a reasonable degree of protection against hazards that research has not yet identified. The margin of safety is designed to prevent pollution levels that have been demonstrated to be harmful, as well as to prevent lower pollutant levels that may pose an unacceptable risk of harm, even if the risk is not precisely identified as to nature or degree. Health protection is achieved if the estimated worst-case exposure is below the relevant reference exposure level. In such a case, an adequate margin of safety exists between the predicted exposure and the estimated threshold dose for toxicity.

Exposure to multiple toxic substances may result in health effects that are equal to, less than, or greater than effects resulting from exposure to the individual chemicals. Only a small fraction of the thousands of potential combinations of chemicals have been tested for the health effects of combined exposures. The health risk assessment assumes that the effects of each substance are additive for a given organ system (OEHHA 2003, pp. 1-5, 8-12). Other possible mechanisms due to multiple exposure include those cases where the actions may be synergistic or antagonistic (where the effects are greater or less than the sum, respectively) (Id). For these types of substances, the health risk assessment could underestimate or overestimate the risks.

For carcinogenic substances, the health assessment considers the risk (expressed in chances per million) of developing cancer and assumes that continuous exposure to the cancer-causing substance occurs over a 70-year lifetime. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound number based on worst-case assumptions. In reality, the risk is generally too small to actually be measured. For example, the ten in one million risk level represents a ten in one million increase in the normal risk of developing cancer over a lifetime, at the geographic location estimated to have the worst-case risk.

Cancer risk is a function of the maximum expected pollutant concentration, the probability that a particular pollutant will cause cancer (called a “potency factor” and established by the California Office of Environmental Health Hazard Assessment - OEHHA), and the length of the exposure period. Cancer risks for each carcinogen are added to yield total cancer risk. The conservative nature of the screening assumptions used means that actual cancer risks are likely to be lower or even considerably lower than those estimated.

Failure to pass the initial screening analysis does not automatically indicate that the project would pose a significant risk to public health, but that a more detailed assessment, using more realistic project-specific assumptions, is necessary to more accurately determine potential public health risks.

SIGNIFICANCE CRITERIA

Commission staff determines the health effects of exposure to toxic emissions based on impacts to the maximum exposed individual. This is a person hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using worst-case assumptions, as described above.

As described earlier, non-criteria pollutants are evaluated for short-term (acute) and long-term (chronic) noncancer health effects, as well as cancer (long-term) health effects. Significance of project health impacts is determined separately for each of the three categories.

Acute and Chronic Noncancer Health Effects

Staff assesses the significance of non-cancer health effects by calculating a "hazard index". A hazard index is a ratio comparing exposure from facility emissions to the reference (safe) exposure level. A ratio of less than one signifies that the worst-case exposure is below the safe level. The hazard index for every toxic substance which has the same type of health effect is added to yield a total hazard index. The total hazard index is calculated separately for acute and chronic effects. A total hazard index of less than one indicates that cumulative worst-case exposures are less than the reference exposure levels (safe levels). Under these conditions, health protection is likely to be achieved, even for sensitive members of the population. In such a case, staff presumes that there would be no significant non-cancer project-related public health impacts.

Cancer Risk

Staff relied upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986 (Health & Safety Code, §§ 25249.5 et seq.) for guidance to determine a cancer risk significance level. Title 22, California Code of Regulations, section 12703(b) states that "the risk level which represents no significant risk shall be one which is calculated to result in one excess case of cancer in an exposed population of 100,000, assuming lifetime exposure." This level of risk is equivalent to a cancer risk of ten in one million, or 10×10^{-6}. An important distinction is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the total risk from all cancer-causing chemicals. Thus, the manner in which the significance level is applied by staff is more conservative (health-protective) than that which applies to Proposition 65.

The significant risk level of ten in one million is consistent with the level of significance adopted by the Mojave Desert Air Quality Management District pursuant to Health and Safety Code section 44362(b), which requires notification of nearby residents when an air district determines that there is a significant health risk from a facility.

As noted earlier, the initial risk analysis for a project is typically performed at a screening level that is designed to overstate actual risks, so that health protection can be ensured. When a screening analysis shows cancer risks to be above the significance level, refined assumptions would likely result in a lower, more realistic risk estimate. If project risk, based on refined assumptions, exceeds the significance level of ten in one million, staff would require appropriate measures to reduce risk to insignificance. If, after all risk reduction measures had been considered, a refined analysis identifies a cancer risk greater than ten in one million, staff would deem such risk to be significant, and would not recommend project approval.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The following state LORS generally apply to the protection of public health. These provisions have established the basis for Energy Commission staff's determination regarding the significance and acceptability of project-related impacts on public health. There are no federal or local LORS that apply directly to the public health analysis of this project.

STATE

California Health and Safety Code sections 39650 et seq.

These sections mandate the Air Resources Board and the Department of Health Services to establish safe exposure limits for toxic air pollutants and identify pertinent best available control technologies. They also require that the new source review rule for each air pollution control district include regulations that require new or modified procedures for controlling the emission of toxic air contaminants.

California Health and Safety Code section 41700

This section states that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."

SETTING

This section describes the environment in the vicinity of the proposed project site from the public health perspective. Features of the natural environment, such as meteorology and terrain, affect the project's potential for causing impacts on public health. An emissions plume from a facility may affect elevated areas before lower terrain areas, due to a reduced opportunity for atmospheric mixing. Consequently, areas of elevated terrain can often be subjected to increased pollutant impacts. Also, the types of land use near a site influence the surrounding population distribution and density which, in turn, affect public exposure to project emissions. Additional factors affecting potential public health impact include existing air quality and environmental site contamination.

SITE AND VICINITY DESCRIPTION

The proposed site is located about five miles west of Blythe in an area that has been designated for industrial development.

The proposed project would occupy parcels of predominantly unimproved land. In the vicinity of the project, land use is primarily agricultural. Directly east and south of the project site, almost 500 acres of lemons are cultivated, and citrus orchards dominate the area. The Blythe airport is about one mile to the west, and the Interstate 10 corridor is

about one-quarter mile to the south. The proposed project would be located southwest of the existing Blythe Energy Project (BEP I).

As mentioned above, the location of sensitive receptors near the proposed site is an important factor in considering potential public health impacts. The nearest residence is about three-quarters of a mile to the southwest, north of Interstate 10 and south of Hobson Way. There are a few farm residences, primarily to the east and south, more than one mile from the site. The nearest residential area is an unincorporated area, called Nicholls Warm Springs (also known as Mesa Verde), located about 2.5 miles to the southwest. There are no sensitive receptor facilities such as schools, hospitals, daycare facilities, or convalescent centers within three miles of the site.

METEOROLOGY

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into ambient air as well as the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants and associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced and localized exposure may be increased.

The locale is a desert climate with low precipitation (less than four inches annually), high temperatures with a wide daily range, and low relative humidity. About 42 percent of precipitation occurs from December through March, and is associated with winter storms from the Pacific Ocean. About 25 percent of precipitation occurs in July and August, and is associated with a monsoonal flow of moisture from the Pacific Ocean and the Gulf of California. Wind directions are predominantly from the southwest from April through September, and from the northeast the remainder of the year. This pattern is highly seasonable and is influenced by the southwest-northeast orientation of the Palo Verde Valley.

Atmospheric stability is a measure related to turbulence, or the ability of the atmosphere to disperse pollutants due to convective air movement. Average monthly mixing heights (the height above ground level through which the air is well mixed and in which pollutants can disperse) range from 800 meters above ground level during winter to near 3000 meters in the summer. Winds are calm approximately 15 percent of the time. Staff's **Air Quality** section presents more detailed meteorological data.

EXISTING AIR QUALITY

Ambient air quality data have not been measured in the Blythe area since 1992 (BEP 2002d, p. 7.7-40). The air quality monitoring data selected as most representative of the Blythe area was collected at Twentynine Palms, located 90 miles west-northwest of Blythe. There are very few sources of industrial pollutants in the Blythe area. No large stationary sources, other than the immediately adjacent BEP I, located approximately 1100 feet northeast and a Southern California Gas compressor facility located about 1.5 miles east-southeast, are sited within a three mile radius of the proposed site.

SITE CONTAMINATION

Site disturbances will occur during facility construction from excavation, grading, and earth moving. Such activities have the potential to adversely affect public health through various mechanisms, such as the creation of airborne dust, material being carried off-site through soil erosion, and uncovering buried hazardous substances.

A Phase I Environmental Site Assessment (ESA) found that the site is not associated with any adverse health effects as a result of onsite historical activities.

IMPACTS

PROJECT SPECIFIC IMPACTS

Potential risks to public health may occur during both project construction and operation.

Construction Impacts

Potential risks to public health during construction may be associated with exposure to toxic substances in contaminated soil disturbed during site preparation, as well as from heavy equipment operation. Criteria pollutant impacts from the operation of heavy equipment and particulate matter from earth moving are examined in staff's **Air Quality** analysis.

As described above and in the **Waste Management** section, the Phase I ESA reported no evidence of widespread site contamination. Therefore, no significant toxics-related public health impacts are anticipated from earth moving due to project construction.

The operation of heavy construction equipment will result in toxic emissions from diesel-fueled engines. Diesel exhaust is a complex mixture of many constituents that could cause adverse health impacts. However, the area of potential impact tends to be very close to the sources, due to the low height of the exhaust stacks. As noted above, the nearest residence is about three-quarters of a mile to the southwest, with a few farm residences located more than one mile from the site. The nearest residential area is located about 2.5 miles to the southwest. Thus, staff does not expect there to be any impact to members of the public from the toxic constituents of diesel equipment exhaust.

Operation Impacts

Emissions Sources

The emissions sources at the proposed BEP II include two combustion turbine generators, two supplementally fired heat recovery steam generators that supply steam to a steam turbine generator, a main cooling tower and an evaporative condenser or cooling tower for inlet chilling (BEP II 2002d, 2002g). During operation, potential public health risks are related to natural gas combustion emissions from the gas turbines and duct burners and noncombustion emissions from the cooling tower.

As noted earlier, the first step in a health risk assessment is to identify potentially toxic compounds that may be emitted from the facility. PUBLIC HEALTH Table 1 lists combustion-related toxic emissions from the turbines and supplementally-fired steam generators and shows how each contributes to the health risk analysis. For example, the first row shows that acetaldehyde may have cancer and chronic (long-term) noncancer health effects, but not acute (short-term) effects.

Noncriteria emissions from the cooling tower originate from contaminants in the cooling source water that become entrained in liquid water droplets emitted as cooling tower drift. PUBLIC HEALTH Table 2 lists these substances and shows how each contributes to the health risk analysis.

PUBLIC HEALTH Table 1
Natural Gas Combustion Emissions and Associated Potential Health Impacts

Substance	Cancer	Chronic Noncancer	Acute Noncancer
Acetaldehyde	3	3	
Ammonia		3	3
Benzene	3	3	3
1,3-Butadiene	3		
Formaldehyde	3	3	3
Napthalene		3	
Polyaromatic Hydrocarbons	3		
Propylene oxide	3	3	3
Toluene		3	
Xylene		3	3

Source: AFC Table 7.8-3, using reference exposure levels and cancer potency factors from OEHHA 2003

The BEP II will use high efficiency drift eliminators which limit the amount of drift loss to approximately 0.0006 percent of the circulating water rate, resulting in a drift rate of about 0.9 gallon per minute (BEP 2002d, page 7.7-11). This amount of water lost as liquid from the cooling towers is in contrast to the amount of water evaporated as steam, estimated to be around 1860 gallons per minute (gpm) for the main cooling tower and about 160 gpm for the inlet chilling cooling tower, depending on ambient temperatures (BEP 2002d, Appendix 7.7-C). Steam emitted from the cooling towers is distilled water, and will not contain contaminants. Similarly, drift eliminators on the inlet air chiller cooling tower will reduce the cooling tower mist to approximately 0.2 gallons per minute based on a loss of 0.001 percent.

PUBLIC HEALTH TABLE 2

Cooling Tower Emissions and Associated Potential Health Impacts

Substance	Cancer	Chronic Noncancer	Acute Noncancer
Arsenic	3	3	3
Cadmium	3	3	
Copper		3	3
Lead	3	3	
Manganese		3	
Mercury		3	3
Nickel	3	3	3
Selenium		3	3
Zinc		3	

Source: AFC Table 7.8-3, using reference exposure levels and cancer potency factors from OEHHA 2003

The drift eliminators must be properly installed and maintained in order to achieve efficient operation over the life of the facility. Following installation, proper maintenance includes periodic inspection and repair or replacement of any components found to be broken or missing. Staff has proposed Condition of Certification **PH–1** to ensure the inspection and maintenance of drift eliminators.

Emissions Levels and Concentrations

Once potential emissions are identified, the next step is to quantify them by conducting a “worst case” analysis.

Estimates of emissions on an hourly and annual basis are required to calculate acute (short-term) and cancer and chronic (long-term) noncancer health effects. BEP II Table 7.7-3 shows maximum fuel use for the gas turbines and duct burners (BEP 2002d, p. 7.7-4). The maximum fuel use is combined with the emission factor for each toxic air contaminant to estimate maximum hourly and annual emissions. Emission factors are estimates of the amounts of toxic substances released per unit of fuel burned from data in the California Air Toxic Emission Factors database maintained by the California Air Resources Board as well as from the U.S. Environmental Protection Agency (U.S. EPA 2000). Emission factors for metals from the cooling tower are derived from analyses of metals concentrations in the water used for cooling.

The next step in the health risk assessment process is to estimate the maximum ambient concentrations of toxic substances. This is accomplished by estimating the maximum impact under a variety of operating conditions and using a screening air dispersion model that assumes conditions resulting in maximum impacts. The screening analysis uses U.S. EPA approved ISCST3 dispersion modeling program (please see staff’s **Air Quality** section for a detailed discussion of the modeling methodology).

Finally, ambient concentrations are combined with RELs and cancer unit risk factors to estimate health effects which might occur from exposure to facility emissions. Exposure pathways, or ways in which people might come into contact with toxic substances, include inhalation, dermal (through the skin) absorption, soil ingestion, and mother's milk.

The above method of assessing health effects is described in OEHHA's Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments (August 2003) and results in the following health risk estimates.

Acute and Chronic Noncancer Hazard

The acute hazard index at the point of maximum impact for substances that could cause short-term health effects is 0.013 (PUBLIC HEALTH Table 3). This means that the air concentration to which the public is exposed is about 77 times lower than an air concentration that is considered safe for all parts of the population, including sensitive subgroups. With the acute hazard index well under the significance level of 1.0, no short-term health effects are expected from routine plant operation.

The chronic hazard index at the point of maximum impact for substances that could cause long-term health effects is 0.002 (PUBLIC HEALTH Table 3) which means that the air concentration to which people are exposed is about 455 times lower than the "safe" level for all parts of the population. The chronic hazard index is well under the safe level of 1.0, culminating in no chronic health effects. Further, all maximum hazard locations are in undeveloped areas, distant from sensitive receptors.

PUBLIC HEALTH Table 3
Facility Hazard/Risk

Type of Hazard/Risk	Hazard Index/Risk	Significance (Safe) Level
ACUTE NONCANCER	0.013	1.0
CHRONIC NONCANCER	0.002	1.0
INDIVIDUAL CANCER	0.298×10^{-6}	10.0×10^{-6}

Source: BEP 2002a AFC

Cancer Risk

As shown in PUBLIC HEALTH Table 3, total worst-case individual cancer risk is estimated to be 0.298 in one million. This is the risk at the location where long-term pollutant concentrations are calculated to be the highest and is thirty-three times lower than the significance level of ten in one million.

Cooling Tower

In addition to being a source of potential toxic air contaminants, the possibility exists for bacterial growth to occur in the cooling tower, including Legionella. Legionella is a bacterium that is ubiquitous in natural aquatic environments and is also widely distributed in man-made water systems. It is the principal cause of legionellosis, otherwise known as legionnaires' disease, which is similar to pneumonia. Transmission to people results mainly from inhalation or aspiration of aerosolized contaminated water.

Untreated or inadequately treated cooling systems, such as industrial cooling towers and building heating, ventilating, and air conditioning systems, have been correlated with outbreaks of legionellosis.

Legionella can grow symbiotically with other bacteria and can infect protozoan hosts. This provides Legionella with protection from adverse environmental conditions, including making it more resistant to water treatment with chlorine, biocides, and other disinfectants. Thus, if not properly maintained, cooling water systems and their components can amplify and disseminate aerosols containing Legionella.

The U.S. Environmental Protection Agency (U.S. EPA) published an extensive review of Legionella in a human health criteria document (EPA 1999). The U.S. EPA noted that Legionella may propagate in biofilms (collections of microorganisms surrounded by slime they secrete, attached to either inert or living surfaces) and that aerosol-generating systems such as cooling towers can aid in the transmission of Legionella from water to air. The U.S. EPA has inadequate quantitative data on the infectivity of Legionella in humans to prepare a dose-response evaluation. Therefore, sufficient information is not available to support a quantitative characterization of the threshold infective dose of Legionella. Thus, the presence of even small numbers of Legionella bacteria presents a risk - however small - of disease in humans.

In 2000, the Cooling Technology Institute (CTI) issued its own report and guidelines for the best practices for control of Legionella (CTI 2000). The CTI found that 40-60 percent of industrial cooling towers tested were found to contain Legionella. It estimated that more than 4,000 deaths per year are believed to occur from Legionellosis (from all sources, not limited to industrial cooling towers), but only about 1,000 are reported. The CTI listed no reference or supportive data for this assertion, however.

To minimize the risk from Legionella, the CTI noted that consensus recommendations included minimization of water stagnation, minimization of process leads into the cooling system that provide nutrients for bacteria, maintenance of overall system cleanliness, the application of scale and corrosion inhibitors as appropriate, the use of high-efficiency mist eliminators on cooling towers, and the overall general control of microbiological populations. Good preventive maintenance is very important in the efficient operation of cooling towers and other evaporative equipment (ASHRAE 1998). Preventive maintenance includes having effective drift eliminators, periodically cleaning the system if appropriate, maintaining mechanical components in working order, and maintaining an effective water treatment program with appropriate biocide concentrations. Staff notes that most water treatment programs are designed to minimize scale, corrosion, and biofouling and not to control Legionella.

The efficacy of any biocide in ensuring that bacterial and in particular Legionella growth, is kept to a minimum is contingent upon a number of factors including but not limited to proper dosage amounts, appropriate application procedures and effective monitoring. Staff has proposed Condition of Certification **PH-2** that would require the project owner to prepare and implement a biocide and bacterial control program. The program, which would have to be approved by Staff, would ensure that proper levels of biocide and other agents are maintained within the cooling tower water at all times, that periodic measurements of Legionella levels are conducted, and that periodic cleaning is

conducted to remove bio-film buildup. Staff believes that with the use of an aggressive antibacterial program coupled with routine monitoring and bacteria removal, the chances of Legionella growing and dispersing would be reduced to insignificant.

CUMULATIVE IMPACTS

Elevated concentrations of toxic air contaminants from stationary sources tend to be localized, and cumulative risks are likely to occur only when multiple facilities with substantial low-level emissions are immediately adjacent to, or very close to, one another. The closest major stationary sources are BEP I and the Southern California compressor station.

Conditions are not conducive for the potential mingling of the emissions from the compressor station and BEP II. This is because of the extended distance and differences in elevation between the station and BEP II and the general prevailing wind direction. Consequently, emissions for the compressor station were not included in the cumulative health risk assessment. Instead, the risk assessment was performed using emission calculations from only BEP I and BEP II. The cumulative excess lifetime cancer risk is estimated to be 0.73 in a million and the cumulative chronic and acute noncancer hazard indices are 0.005 and 0.027 respectively. The levels are well below their significance levels and staff does not expect any cumulative health impacts to be significant.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is more than 50 percent within a six-mile radius of the proposed BEP II (please refer to **Socioeconomics Figure 1** in this staff assessment). Staff also reviewed Census 2000 information that shows the low-income population is less than fifty percent within the same radius.

Based on the **Public Health** analysis staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project and, therefore, there are no public health environmental justice issues related to this project.

FACILITY CLOSURE

As noted in the introduction to this section, the scope of staff's public health analysis is limited to routine releases of harmful substances to the environment. During either temporary or permanent facility closure, the major concern would be from accidental or nonroutine releases from either hazardous materials or wastes which may be onsite. These are discussed in the sections on **Hazardous Materials** and **Waste Management**, respectively. During temporary closure (periods greater than those required for normal maintenance), it is unlikely that there would be any routine releases of harmful substances to the environment, since the facility would not be operating. For permanent closure, the only routine emissions would be related to facility demolition or dismantling, such as exhaust from heavy equipment or fugitive dust emissions. These

would be subject to closure conditions adopted by the Energy Commission once a closure plan is received from the project owner.

MITIGATION

Noncriteria emissions from the proposed project are determined by many factors such as mode of facility operation, type of pollution control equipment, and type of fuel used. Please refer to the **Air Quality** section of this document for a detailed description and analysis of air pollution mitigation measures. Additionally, staff has proposed two Conditions of Certification to mitigate potential health impacts from cooling tower drift.

COMPLIANCE WITH APPLICABLE LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Staff concludes that construction and operation of BEP II will be in compliance with all applicable LORS regarding long-term and short-term project impacts.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

No public agency or public comments have been received in connection with the project-related impacts discussed in this analysis.

CONCLUSIONS AND RECOMMENDATIONS

Staff has analyzed potential public health risks associated with construction and operation of the BEP II. With implementation of the conditions of certification included herein, as noted, staff does not expect there to be any significant adverse cancer, or short- or long-term noncancer health effects from project emissions.

CONDITION OF CERTIFICATION

Public Health-1 The project owner shall perform a visual inspection of the cooling tower drift eliminators once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to initial operation of the project, the project owner shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminator and certify that the installation was performed in a satisfactory manner. The CPM may, in years 5 and 15 of project operation, require the project owner to perform a source test of the PM10 emissions rate from the cooling tower to verify continued compliance with the vendor guaranteed drift rate.

Verification: The project owner shall include the results of the annual inspection of the cooling tower drift eliminators and a description of any repairs performed in the next required annual compliance report. The initial compliance report will include a copy of the cooling tower vendor's field representative's inspection report of the drift eliminator installation. If the CPM requires a source test as specified in Public Health-1, the project owner shall submit to the CPM for approval a detailed source test procedure 60

days prior to the test. The project owner shall incorporate the CPM's comments, conduct testing, and submit test results to the CPM within 60 days following the tests.

Public Health-2 The project owner shall develop and implement a Cooling Water Management Plan to ensure that the potential for bacterial growth in cooling water is kept to a minimum. The Plan shall be consistent with either Staff's "Cooling WaterManagement Program Guidelines" or with the Cooling Technology's Institute's "Best Practices for Control of Legionella" guidelines.

Verification: At least 30 days prior to the commencement of cooling tower operations, the Project Owner shall provide the cooling water management plan to the CPM for review and approval.

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ATTACHMENT A - CRITERIA POLLUTANT HEALTH EFFECTS

OZONE (O_3)

Ozone is formed when reactive organic gases are mixed with nitrogen oxides in the presence of sunlight. Heat speeds up the reaction, typically leading to higher concentrations in the summer months. Ozone is a colorless, very reactive gas which oxidizes other materials. Oxidation damages living cells and tissues by altering their protein, lipid, and carbohydrate components or products. Such damage leads to dysfunction and death of cells in the lung and in other internal tissues.

The U.S. EPA revised the federal ozone standard on July 18, 1997 (62 Fed. Reg. 38856), based on new health studies which became available since the standard was last revised in 1979. These new studies showed that adverse health effects occur at lower ambient concentrations over longer exposure times than those reflected in the previous standard, which was based on acute health effects associated with heavy exercise and short-term exposures. The U.S. EPA's proposed ozone rule lists health effects which have been attributed to result from short-term (one to three hours) and prolonged (six to eight hours) exposure to ozone (61 Fed. Reg. 65719). However, a 1999 federal court ruling blocked implementation of the ozone 8-hour standard. EPA has asked the U.S. Supreme Court to reconsider that decision.

Acute health effects induced by short-term exposures include transient reductions 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 associated with short-term or prolonged O_3 exposures include increased airway responsiveness (a predisposition to bronchoconstriction caused by external stimuli such as pollen and dust), susceptibility to respiratory infection by impairing 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 are children and adults engaged in physical exercise. Children are most at risk because they are active outside, playing and exercising, during the summer when ozone levels are at their highest. Adults who are outdoors and engaging in activities involving heavy levels of exertion during the summer months are also among those most at risk. 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, but is 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, 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 produced significant cardiac effects. These included earlier onset of 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, impairment of central nervous system functions, and increased risk to fetuses (Title 17, Cal. Code Regs., §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 (known as 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.

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.

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.

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 it is deposited in the respiratory system. 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. Until recently, PM10 particles had been considered to be the major fraction of airborne particulates responsible for various adverse health effects. The PM10 fraction is known to be capable of penetrating the thoracic and alveolar regions of the human and animal lungs. The PM2.5 fraction, however, was found to pose a significantly higher risk for health. This is due to their size and associated deposition and retention characteristics in the respiratory tract, enabling it to penetrate and deposit within the deeper alveolar regions of the lung. The following aspects of PM2.5 deposition all contribute to the more serious health effects attributed to smaller particles:

- The deposition of PM2.5 favors the periphery of the lungs, which is especially vulnerable to injury for anatomical reasons.

- Clearance of the PM2.5 from within the deeper reaches of the lungs is a much slower process than from the upper regions. Consequently, the residence time is longer, implying longer exposure, and hence greater risk.

- The human anatomy further allows the penetration of the superficial tissues by PM2.5 and entry into the bodily circulation without much effort in the periphery of the lungs.

Many epidemiological studies have shown exposure to particulate matter capable of inducing 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 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, the U.S. 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 also had 24-hour and annual standards for PM10 (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 (Tit. 17, Cal. Code Regs., §70200). These standards were set to be more stringent than the federal standard, which the ARB regarded as inadequate for the protection desired (CARB 1991, p. 26).

On June 20, 2002, the ARB approved the adoption of a lower annual state standard for PM10, as well as a new annual standard for PM2.5 (CARB 2002). The new standards took effect on July 5, 2003. The 24-hour PM10 standard was not changed. The standards were established to prevent excess death, illnesses such as respiratory symptoms, bronchitis, asthma exacerbation, and cardiac disease, and restrictions in activity from short- and long-term exposures (Title 17, Cal. Code Regs., §70200).

NITROGEN DIOXIDE (NO_2)

Nitrogen dioxide is formed either directly or indirectly when oxygen and nitrogen in the air combine during combustion processes. It is a relatively insoluble gas which is able to penetrate deep into the lungs, its principal site of toxicity. Its toxicity is thought to be due to its capacity to initiate free radical reactions and to oxidize cellular proteins and other biomolecules (CARB 1992, Appendix A, p. 4).

Sublethal exposures in animals produce inflammation and various degrees of tissue injury characteristic of oxidant damage (Evans in CARB 1992, Appendix A, p. 5). The changes produced by low-level acute or subchronic exposure appear to be reversible when animals are 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 (CARB 1992, Appendix A, 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 using controlled brief exposures on sensitive groups have shown an increase in bronchial reactivity or airway responsiveness of some asthmatics, and decreased lung function in some patients with chronic obstructive lung disease (CARB 1992, Appendix A, p. 2). In general, bronchial hyperreactivity (an exaggerated tendency of the airways to constrict) is markedly greater in asthmatics than in nonasthmatics upon exposure to respiratory irritants (CARB 1992a, p. 107). At exposure concentrations relevant 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 cause 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 an increased incidence of respiratory symptoms (e.g., coughing and wheezing) or respiratory disease, decreases in pulmonary function, and an increased risk of mortality (CARB 1991a, p. 12). The long-term (24 hour) standard is based upon increased incidence of respiratory disease and excess 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, whereby

"no adverse effects" are expected from exposures to concentrations at the state standard (Ibid.).

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SOCIOECONOMICS

Testimony of Amanda Stennick

INTRODUCTION

The California Energy Commission (Energy Commission) staff's socioeconomics impact analysis evaluates several areas in which the project may induce changes including community services and/or infrastructure and related community issues such as facility closure. Direct, indirect, and cumulative impacts are included in the evaluation. This analysis discusses the potential impacts of the proposed Blythe Energy Project Phase II (BEP II) on local communities, community resources, and public services, pursuant to Title 14, California Code of Regulations, Section 15131, and examines the project's compliance with applicable laws, ordinances, regulations and standards.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

California Government Code, sections 65995-65997 as amended by SB 50 (Stats. 1998, ch. 407, sec. 23), states that public agencies may not impose fees, charges or other financial requirements to offset the cost for school facilities. The relevant provisions restrict fees for the development of commercial and industrial space to a maximum of $0.31 per square foot of "chargeable covered and enclosed space" and are payable to the local school district.

ENVIRONMENTAL SETTING

BEP II will be located in eastern Riverside County approximately five miles west of the City of Blythe and two miles northeast of the unincorporated community of Mesa Verde. Blythe is about 171 miles east of the City of Riverside, on the Arizona border. BEP II will be located on a 76-acre tract adjacent to the current Blythe Energy Project (BEP I) that was approved by the California Energy Commission on March 21, 2001. The BEP I is currently operating and is owned by FPL Energy.

ANALYSIS AND IMPACTS

Staff reviewed the BEP II AFC, Vol. I, July 2002, Sections 7.6, **SOCIOECONOMICS** regarding potential impacts to community services and infrastructure (i.e., employment, housing, schools, utilities, emergency and other services), 7.13, **WATER RESOURCES**, and 7.14 **AGRICULTURE AND SOILS** regarding water use.

To assess the availability of local housing for project construction workers, staff looks at the current vacancy rate with a level of five percent or less indicating a tight housing market. Criteria for subject areas such as fire protection, water supply and wastewater disposal are analyzed in other sections of this staff assessment. Impacts to school enrollment and capacities are determined based on the potential for in-migration of construction workers and their school-age children. Impacts on medical services, law enforcement, or community cohesion are based on subjective judgments or input from

local and state agencies. Typically, an influx of non-local employees has the potential to result in significant impacts.

POPULATION AND DEMOGRAPHICS

The historical and current populations of Blythe and Riverside County are shown in **SOCIOECONOMICS Table 1**.

SOCIOECONOMICS Table 1
Historical and Current Populations

	Historical Population			
AREA	**1990**	**2000**	**Percent Change**	**Annual Growth Rate %**
California	29,760,021	33,871,648	13.8	1.3
Riverside County	1,170,413	1,545,387	32.0	2.8
City of Riverside	226,505	255,166	12.7	1.2
City of Blythe excluding correction facilities	8,428	12,155	44.2	3.2

Source: U. S. 2000 Census

LABOR FORCE

The BEP II will require a pool of skilled laborers. As shown in **SOCIOECONOMICS Table 2**, Riverside County has a substantial skilled labor force from which to draw.

SOCIOECONOMICS Table 2
Available Labor By Skill In Riverside County, 1999 To 2006

	Annual Averages		Percent Change
Occupational Title	**1999**	**2006**	
Carpenters	7380	10,100	36.9
Masons and Related Workers	3,050	4,070	33.4
Painters and Related Workers	1,430	1,900	32.9
Metal Workers	360	460	27.8
Electricians	2,160	2,840	31.5
Welders	870	1,130	29.9
Excavators	420	550	31.0
Graders	610	760	24.6
Industrial Truck Operator	1,270	1,610	26.8
Operating Engineers	760	960	26.3
Helpers, laborers	21,300	27,580	29.3
Pipefitters	1,620	2,120	30.9
Administrative Services Managers	1,180	1,480	25.4
Mechanical Engineers	510	700	37.3
Electrical Engineers	440	590	34.1
Engineering Technicians	2,260	2,940	30.1
Plant and System Operators	350	440	25.7

Source: Employment Development Department Riverside County

SCHOOLS

The Palo Verde Unified School District serves the BEP II. The school district is composed of three elementary schools, one middle school, one high school, and one secondary-level continuation school. The community also has a two-year community college and two private schools: The Zion Lutheran School and the Escuela De La Raza Unida School. **SOCIOECONMICS Table 3** shows the most current data available from the California Department of Education's website. For the 2003-2004 school year, District enrollment was 3,677.

SOCIOECONOMICS Table 3
PALO VERDE UNIFIED SCHOOL DISTRICT, ENROLLMENT AND CAPACITY

Schools	Enrollment Figures	Enrollment Capacity	Percent Capacity
Elementary			
Felix J. Appleby	570	745	76.5
Ruth Brown	609	780	78.0
Margaret White	750	680	110.3
Sub Total	1,929	2,225	86.7
Middle School			
Blythe Middle School	757	993	76.2
High School			
Palo Verde High School	927	1,140	81.3
Twin Palms Continuation High School	64	100	64.0
Grade 1-12 Total	3,677	4,438	82.8
College			
Community College	1,250	N/A	

Source: DOE; Educational Demographics Unit.

EMPLOYMENT

The AFC estimates that project construction activity will occur over 20 months. The labor force required for construction of the BEP II includes boilermakers, carpenters, electricians, ironworkers, laborers, millwrights, operators, pipefitters and others. The employed force would include both skilled and non-skilled workers. Based on occupational employment projections by the California's Employment Development Division (see **SOCIOECONOMICS Table 2**) there are enough skilled laborers for project construction.

The labor force for construction of BEP II is expected to peak in the 12th month after the start of construction at 387 (see **SOCIOECONOMICS Table 4**).

If additional workers are required, the project could draw from population centers in the region such as Las Vegas, Yuma, and Phoenix. Therefore, staff believes that sufficient workers for construction of the BEP II are available within the general area. Most of the workforce will be within a one-way commute time of two hours from the plant site. The demand for skilled laborers should not result in a community labor shortage.

During operation of the project, about 20 permanent workers will be needed to maintain and operate the project (12 to 14 operating technicians, 3 to 4 maintenance technicians and 3 to 4 administrators). Staff does not expect the number of employees required for operation of BEP II to cause a significant impact on the local labor force.

SOCIOECONOMICS Table 4
Blythe II Energy Project Estimated Construction Staffing

Construction months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Insulation Workers										9	17	21	28	28	21	17	14	9	6	2
Boiler Makers						14	21	30	30	30	30	30	24	19	19	9	9	9	6	2
Masons		2	5	9	9	9	9	5	3	2	1	1	1	1	1	1	1	1	1	0
Carpenters	10	13	15	22	30	36	40	40	35	29	23	23	23	19	12	10	10	10	6	0
Electricians	4	4	8	8	14	28	28	33	38	43	47	57	47	42	36	24	14	14	10	8
Iron Workers	3	7	7	10	15	26	33	39	39	33	26	19	14	9	9	9	9	9	5	2
Laborers	14	20	20	26	31	33	38	38	38	33	33	34	33	24	19	19	14	14	8	4
Millwrights	0	0	0	5	5	8	8	11	11	14	14	14	9	9	9	8	8	8	6	4
Operating Engineers	4	6	8	11	11	13	13	15	17	17	17	18	17	11	9	9	5	5	4	2
Plasterers	0	0	0	0	0	0	0	2	2	4	4	6	4	4	2	0	0	0	0	0
Pipefitters	4	8	10	10	17	19	26	36	50	64	83	93	99	93	82	57	28	24	15	8
Sheer-metal Workers	0	0	0	0	0	0	0	0	6	9	9	14	17	14	9	9	9	6	4	2
Sprinkler Fitters	0	0	0	0	0	0	0	1	1	1	1	4	8	11	8	4	2	2	1	1
Surveyors	2	2	3	4	4	4	4	4	4	4	4	4	4	4	2	2	1	0	0	0
Teamsters	0	0	0	1	1	2	2	2	2	2	2	2	2	2	2	2	1	0	0	0
Total BEP II Power Plant Manual Staff	41	62	76	106	137	193	222	256	276	294	311	340	330	290	240	180	125	111	72	35
Total BEP II Power Plant Contractor Staff	6	11	17	23	28	33	38	38	47	47	47	47	47	38	36	28	28	26	20	10
Total BEP II Power Plant Site Staff	47	73	93	129	165	225	260	294	323	341	358	387	377	328	276	208	153	138	92	45
BEP Staffing	276	208	153	137																
Total Both Projects	323	281	246	266	165	225	260	294	323	341	358	387	377	328	276	208	153	138	92	45

Source: BEP II 2002a, AFC

HOUSING

The BEP II could cause a tight housing market during construction if a large number of the workers relocate to the area. However, the Blythe area has supported a labor force for the construction of two prisons, Ironwood State Prison, which opened in February 1994, and Chuckawalla Valley Prison, which opened in December 1988, and BEP I. During the construction of these projects there was a maximum of 250 to 300 construction workers involved (BEP 1999). There was no noticeable shortage of housing for these workers during construction. Many of the workers brought recreational vehicles (RV) with them and took advantage of the many RV parks in the area for housing during construction.

The most current available data (March 2002) from the Department of Finance (DOF) show that there were about 595,682 total housing units in Riverside County, with a vacancy rate of 13.4 percent. For the same period of time, the DOF estimated about

4,840 total housing units in Blythe, with a vacancy rate of 16.1 percent. Residential construction in the Blythe area includes 23 motels with about 1,100 rooms, over 300 mobile home spaces, over 600 RV spaces, and condominiums and apartments since the two prisons opened.

There are an additional 78 motels within 65 miles of Blythe (Yahoo 2004), which would result in a commute of one hour or less for workers using these facilities. The lodging combination of housing, apartments, motel/hotel rooms, and RV spaces available to non-local construction and operation workers for this project should be sufficient.

Those employees seeking long-term residences could take advantage of new housing development that has been occurring within the City. The long-term operations of the facility would result in only a small increase in population with only 20 full-time employees required to operate the facility.

One possible concern for short-term housing is the influx of visitors during the winter. The population in the Palo Verde Valley triples during the winter season due to visitors attracted to the area because of its warm climate. Because a majority of the individuals coming to the area during the winter season typically use motor homes, trailers, and campers for their accommodations, staff expects that any potential housing needs for the BEP II construction workforce can be met by the City of Blythe and surrounding areas.

SCHOOLS

The Palo Verde Unified School District experienced its peak enrollment in the 1994-1995 school year at 4,050 students. Since that time, school enrollment has declined approximately 1.5 percent annually. Current enrollment is about 3,677 students.

Construction of the proposed project is not expected to result in significant population changes for the school system as most of the construction workers are expected to commute to the work site. The operation of the BEP II will require a small work force of 20 employees. Therefore, if necessary, the Palo Verde Unified School District should be able to absorb additional students due to operation at the BEP II.

If the Palo Verde Unified School district should require additional facilities, the funding would be through either property taxes or statutory facility fees. The Palo Verde Valley Unified School District has in place an impact fee of $0.31 per square foot for new construction of commercial/industrial buildings.

PUBLIC SERVICES

Please refer to the section on **WORKER SAFETY AND FIRE PROTECTION** for a discussion of fire protection services, potential impacts, and proposed mitigation.

Electricity And Gas

The project proposes to interconnect with the regional electric transmission grid at Western's Buck Boulevard Substation located within 800 feet of the BEP II power island. Natural gas would be supplied to the BEP II by the existing gas pipeline that serves BEP I.

Water Supply, Agricultural Water, and Water Conservation Offset Program

The BEP II would use about 3,300 acre-feet of water annually supplied by on-site wells for cooling and other purposes. BEP II is proposing a water conservation offset program (WCOP). As part of this water conservation effort, the WCOP would retire or fallow lands within the Palo Verde Irrigation District's (PVID) service area that are or have been irrigated within the past five years. These lands also would be situated in the Mesa Verde and/or the Palo Verde Valley. BEP II has provided little information about the program, including information as to how the plan would be implemented, managed, monitored, reported and verified to ensure the fallowing program does not lead to significant environmental impacts. For more information on water supply, see the **SOILS AND WATER RESOURCES** and the **LAND USE** sections of this Final Staff Assessment.

Based on a consumptive water use volume of 4.2 acre-feet per acre per year and BEP II's proposed usage of 3,300 acre-feet of water per year, the WCOP for BEP II would fallow about 786 acres of irrigated farmland every year for the life of the project.

To assess the potential impacts of the WCOP, staff reviewed the 2002 Socioeconomic Assessment of the Proposed Palo Verde Irrigation District Land Management, Crop Rotation and Water Supply Program (M. Cubed report). Although PVID's proposed program would provide considerably more water for non-agricultural uses than the WCOP (about 25,000 to 110,000 acre-feet per year), the study area for both programs is the same geographic area. Staff's concern is the potential for job loss in the farm labor, farm services, and farm supply sectors resulting from removing 786 irrigated acres out of production to allow agricultural water to be used for non-agricultural purposes.

For the PVID program, the M. Cubed report performed an input/output analysis using an Impact Analysis for Planning (IMPLAN) model to determine income and employment impacts resulting from direct changes in production and local spending. The report found that the anticipated net job loss would be between 40 and 93 full-time equivalent (FTE) jobs, depending on the number of acres fallowed. An FTE job represents 2,040 person hours per year, or one person working 40 hours per week for 51 weeks. The acreage to job loss ratio used in the M. Cubed study was 0.00805 (Mitchell 2005). This number represents the number of FTE jobs lost from removing one acre from agricultural production.

It is important to note that the acreage to job loss ratio depends upon the mix of crops taken out of production. In the M. Cubed report, the crops used to determine job loss were highly mechanized crops such as hay, alfalfa, cotton, and grains. If labor intensive crops such as orchards, melons, citrus, and vegetable crops were taken out of production, the acreage to job loss ratio would be much higher (Mitchell 2005).

To determine a range of potential jobs lost for this analysis, staff asked Mr. Mitchell if he could provide an acreage to job loss number based on labor intensive crops; Mr. Mitchell could not readily provide that number. Staff reviewed the University of California Cooperative Extension website but was unable to locate a number.

Therefore, staff used the number 0.00805 provided by Mr. Mitchell in the M. Cubed report to determine the number of jobs lost per acre.

The WCOP proposes to retire or fallow 786 acres within the PVID service area. Therefore, the resulting job loss would be 6.33 FTE jobs (0.00805 x 786) within the PVID. Staff does not consider this to be significant.

Sewer

BEP II would dispose of its wastewater through its own septic tank and leach field system. There are two wastewater treatment facilities in the Blythe area; one located south of Blythe, about five miles from the BEP, the other, an oxidation lagoon located east of the Blythe airport that is used to treat airport wastewater. The BEP II will not impact either of these wastewater facilities, as the project will handle its wastewater and sewage treatment on-site during construction and operation (BEP II 2002). Please refer to the **SOILS AND WATER RESOURCES** and **BIOLOGICAL RESOURCES** sections for a detailed discussion of wastewater disposal.

Law Enforcement

The Blythe Police Department provides law enforcement for the City of Blythe. The Department is located at 249 North Spring Street, about five miles from the power plant. The current police department has a staff of 25 law enforcement officers. The Department estimates that emergency response time to the project would be about three minutes. Non-emergency response would be about seven minutes.

The City of Blythe has mutual aid agreements with other law enforcement organizations in the community. This includes the Riverside County Sheriff's Department, located at 260 North Spring Street in Blythe about five miles from the site. The Blythe station has 18 sworn full-time law enforcement officers and handles emergency calls for county residents in the general Palo Verde Valley. The estimated normal response time for a patrol vehicle to the BEP II would be about ten minutes.

Other law enforcement services would be provided by the California Highway Patrol station located about five miles from the BEP II site at 430 South Broadway in Blythe.

The applicant expects that construction and operation of the project would not result in significant demands on law enforcement.

Hospitals and Medical Services

Palo Verde Hospital is located at 250 North 1st Street in Blythe, about five miles east of the BEP II site. The hospital is a 55-bed acute care facility and has 24-hour emergency room service, 23 physicians/surgeons, six dentists, four optometrists, four chiropractors, and one podiatrist.

If required, other medical services are available in the area. Located approximately 30 miles from the BEP II in Parker, Arizona is the La Paz Medical Center. This is a full service hospital with eight doctors on staff, 39 beds and 24-hour emergency service. The community of Quartzsite has a clinic that offers daytime services and is associated with the La Paz Medical Center. Other medical facilities are located approximately 70

miles from the site, with the largest being the Yuma Regional Medical Center in Yuma, Arizona with 237 beds.

Staff believes these services are adequate to meet the medical service needs of the BEP II during construction and operation.

FINANCIAL

The City of Blythe and Riverside County, schools and other special districts in the BEP II Tax Rate Area will receive property tax revenue from the BEP II property. A "Tax Rate Area" is a grouping of properties within a county wherein each parcel is subject to the taxing powers of the same combination of taxing agencies. The BEP II will undergo annual reassessment at fair market value, and property tax collected will be distributed exclusively to the taxing jurisdictions within the Tax Rate Area in which the facility is located.

The local community will also receive a small amount of revenue from sales taxes on equipment, and material and supplies purchased during construction and operation. The applicant estimates that the cost for material and supplies for construction will be $60 million. Of this amount, about $5 to $10 million of material and supplies will be purchased locally. Sales tax in Riverside County is 7.75 percent, of which the City of Blythe would receive one percent.

Impacts from construction include economic gains as a direct result of locally purchased materials and supplies, and construction payroll spending. Indirect or secondary impacts from construction could include increased employment for local workers in other areas of service, such as wholesale and retail, transportation, entertainment, and other business services.

In the AFC, the applicant states that to maintain the BEP II during its operating life will require major maintenance for the facility every 3 to 4 years at an estimated cost of $10 million. Approximately 15 percent, or $1.5 million of this would be spent locally. Operation of the BEP II will require 20 full-time employees. As stated in the AFC, an employee's annual salary will average about $50,000, and will result in an average annual operating payroll of $1.0 million.

ENVIRONMENTAL JUSTICE

For all energy facility siting cases, Energy Commission staff conducts the environmental justice screening analysis in accordance with the "Final Guidance for Incorporating Environmental Justice Concerns in USEPA's National Environmental Policy Act (NEPA) Compliance Analysis" dated April 1998. The purpose of the screening analysis is to determine whether there exists a minority or low-income population, within the potentially affected area of the proposed site. Please refer to the **INTRODUCTION** section of this document for a discussion on LORS related to Environmental Justice and a list of technical areas used to perform an Environmental Justice analysis.

Minority Populations

Minority populations, as defined by USEPA's 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.

In 1997, the President's Council on Environmental Quality issued Environmental Justice Guidance that defines minorities as individuals who are members of the following population groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black not of Hispanic origin; or Hispanic.

Low-Income Populations

According to USEPA's guidance document, low-income populations are identified with the annual statistical series poverty thresholds from the Census Bureau's Current Population Reports, Series P-60 on Income and Poverty. The Census Bureau uses a set of money income thresholds that vary by family size and composition to determine who is poor. The thresholds are used to determine which families are at, above, or below the poverty level. If the total income for a family or unrelated individuals falls below the relevant poverty threshold, then the family or unrelated individuals are classified as being below the poverty level. Poverty status is determined for all people except institutionalized people, people in military group quarters, and people in college dormitories. The official poverty thresholds do not vary geographically but are updated annually for inflation using the Consumer Price Index. The official poverty definition counts money income before taxes and does not include capital gains and non-cash benefits such as public housing, Medicaid, and food stamps. The poverty threshold in 2003 (most current data) for a family of four (two adults and two related children under 18) was $18,660.

Potentially Affected Area

Energy Commission staff has determined that the potentially affected area is within a six-mile radius of the proposed site. As shown in **SOCIOECONOMICS FIGURE 1**, the population within this area totals 12,170. The people of color within this area total 7,216, or 59.29 percent of the total population. In addition, there are multiple census blocks with greater than 50 percent minority populations within the six-mile radius. Because the screening analysis shows a greater than 50 percent minority population within the six-mile radius, staff considered environmental justice as part of the analysis in the technical areas listed in the **INTRODUCTION.**

As shown in **SOCIOECONOMICS FIGURE 1,** BEP I and BEP II are located about two miles from Mesa Verde/Nicholls Warm Springs, a small, unincorporated residential and largely Spanish-speaking community in the Palo Verde Mesa. Residents of this community and Blythe actively participated in the workshops and hearings for BEP I. Some residents of Blythe became intervenors in BEP I and are currently intervenors in BEP II. Although concerns for the health and well-being of the community expressed by the intervenors in BEP I included air quality impacts, their primary concern was the economic and environmental impacts associated with pumping groundwater. Despite

the concerns of the community, the Commission found that all environmental issues had been analyzed and mitigated to a level below significance. To date, the concerns raised by intervenors in BEP II involve depletion of water in the Mesa Verde aquifer, air pollution, loss of citrus orchards and farm worker jobs, destruction of ancient and indigenous sites, and impacts to biological resources.

Summary

Census 2000 shows that the data set "Population for Whom Poverty Is Determined" totals 9,933 persons. Of these, 2,046 persons, or 20.1 percent, are below the poverty level. The Guidance does not give a numerical threshold level for poverty as it does for minority. In the absence of a threshold, staff has used the greater than 50 percent threshold for poverty levels. However, 20.1 percent of the population that is below the poverty level indicates a high degree of poverty in the six-mile radius.

The minority population and low-income population within the six-mile radius are 59.29 percent and 20.1 percent, respectively. Based on the socioeconomic analysis, the proposed project would not result in significant, adverse socioeconomic impacts to housing, schools, public services, police and fire protection, and fiscal resources. Job loss resulting from implementation of the WCOP would be minimal and therefore would not affect the minority population employed in the farm labor, farm services, and farm supply sectors.

CUMULATIVE IMPACTS

The potential for cumulative socioeconomic impacts exists when there are other projects proposed in the region that have overlapping construction schedules that could impact similar resources. Staff is currently reviewing the Blythe Energy Project Transmission Line (BEPTL) Petition for Post-Certification Amendment (99 AFC-8C) and expects the project to come before the Commission in the Fall of 2005. The 12-month construction phase would begin upon certification of the project. The applicant expects the peak construction labor force to total 162 workers. Despite the recent growth and developments in Riverside County, **SOCIOECONOMICS Table 2** shows no shortage of available skilled construction workers in the county. No housing shortages were identified for BEP I and staff does not expect any housing shortage due to construction of BEP II. Therefore, construction and operation of the BEP II would not result in any significant cumulative impacts to housing and construction worker availability.

The M. Cubed report on PVID's program found that the anticipated job loss would be between 40 and 93 FTE jobs, based on a minimum to maximum number of acres fallowed. Implementation of the WCOP would result in the loss of 6.33 FTE jobs or an anticipated cumulative total loss of between 46.33 and 99.33 FTE jobs. Staff notes that the M. Cubed report shows that the impacts of PVID's program would not be distributed uniformly through the study area's economy and that in some employment sectors, full-time jobs would be created as a result of fallowing. In addition, monies paid to participants of the fallowing program would be returned to the community in the form of purchasing and debt payment. Staff also notes that beneficial impacts from construction and operation of BEP II, such as locally purchased materials and supplies and construction payroll spending would offset the 6.33 FTE jobs lost through the WCOP.

SOCIOECONOMICS - FIGURE 1

Blythe Power Project - Census 2000 Minority Population by Census Block - Six Mile Buffer

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: California Energy Commission Statewide Transmission & Power Plant Maps 2003, Census 2000 PL 94-171 Data - Matrix PL2

RESPONSE TO APPLICANT'S COMMENTS ON BEP II PRELIMINARY STAFF REPORT

Comment #1. Applicant's comment clarifies ownership of BEP I. Staff agrees with the comment and has made the change.
Comment #2. Applicant's comment disagrees with staff's statement that the WCOP lacks detail for adequate analysis. Staff has analyzed the WCOP to the extent information provided by the applicant allows.
Comment #3. Applicant's comment clarifies number of wells to supply water for power plant needs. Staff agrees with the comment and has made the change.
Comment #4. Applicant's comment addresses groundwater use and level of impact significance to PVID's water supply, its users, and cumulative impact to Colorado River water. Staff notes the comment and states that the **SOCIOECONOMICS** analysis refers the reader to the **SOILS AND WATER** section for a complete analysis of BEP II's water use.
Comment #5. Applicant's comment clarifies information on wastewater disposal. Staff agrees with the comment and has made the change.

FACILITY CLOSURE

The socioeconomic impacts of permanent facility closure will be evaluated at the time under the Energy Commission's facility closure process.

Any unexpected, temporary closure would not likely cause any significant environmental impacts on the affected area, because the likely result of a temporary closure would be reactivation of the power plant by the same or a new owner within a relatively short period of time. Personnel changes may occur if there is an ownership change, but socioeconomics impacts would not change significantly because the number of operating personnel would remain relatively the same.

Any unexpected, permanent closure of the BEP II is not likely to cause any significant socioeconomics impacts on the affected area, because facility closure impacts (i.e., dismantling) would be similar to construction impacts, and staff has found no significant socioeconomics impacts due to the construction of the project.

MITIGATION

Staff does not expect the proposed project to have significant adverse socioeconomic impacts to housing, schools, public services, police and fire protection, and fiscal resources. Therefore, staff proposes no conditions except the condition that the applicant be required to pay the statutory school impact fees.

CONCLUSIONS AND RECOMMENDATIONS

The BEP II, both directly and indirectly will not cause a significant adverse impact on the affected area's housing, schools, police, fire, emergency services, hospitals, or utilities during construction or operation.

The BEP II will result in some benefits for Riverside County from property and sales tax. The City of Blythe may also benefit from the economic activity generated by the purchase of services, manufactured goods and equipment from local businesses. For example, during construction the project is expected to result in purchases of goods and services in the community of about $5 to $10 million. During plant operation, local expenditures will be about $1.5 million every three to four years.

Staff expects that implementation of the WCOP would result in a loss of about 6.33 FTE jobs, which is not considered significant. To ensure that job loss remains at a less than significant level, staff recommends that only highly mechanized crops such as grains, cotton, and alfalfa be fallowed or rotated as part of the WCOP. Labor intensive crops such as orchards, melon, vegetable, and citrus will be excluded from participating in the WCOP. To that effect, staff proposes Condition of Certification **SOCIO-2**.

SOCIOECONOMICS Table 5 summarizes key data and information from this analysis.

Socioeconomic Data and Information - Table 5

Estimate of Locally Purchased Materials	
Construction	$5-10 million annually
Operation	$1.5 million annually
Existing /Projected Unemployment Rates	5.5% / 5.2%
Percent Minority Population (6 mile radius)	59.29%
Percent Poverty Population (6 mile radius)	20.1%

PROPOSED CONDITIONS OF CERTIFICATION

For the area of socioeconomics, staff recommends that should the BEP II be approved, the proposed conditions of certification be adopted.

SOCIO-1 The project owner shall pay the statutory school impact development fee as required at the time of filing for the “in-lieu” building permit.

Verification: The project owner shall provide proof of payment of the statutory development fee to the Compliance Project Manager (CPM) in the next Monthly Compliance Report following the payment.

SOCIO-2 For the life of the project, the WCOP shall preclude acreage used for “labor intensive” crops, such as orchards, melons, vegetables, and citrus from participating in the WCOP.

Verification: On an annual basis, the project owner shall provide to the Compliance Project Manager (CPM) in the Compliance Report verification that only acreage used to grow “highly mechanized” crops is allowed to participate in the WCOP.

REFERENCES

Agricultural Commissioner's Office, Riverside County. Palo Verde Valley Acreage and Agricultural Crop Report. 2001.

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SOIL AND WATER RESOURCES SUMMARY

Testimony of Natasha Nelson

SUMMARY OF CONCLUSIONS

The proposed Blythe Energy Project Phase II (BEP II) is located in a desert environment which depends on groundwater to supply its industrial and domestic users. The project's proposed unmitigated consumptive use of groundwater derived from the Colorado River for cooling would result in the degradation of the water quality in nearby wells. The proposed use of Colorado River water for the power plant cooling is inconsistent with the Energy Commission's policy as adopted in the 2003 Integrated Energy Policy Report. The loss of this water is complicated by the fact that it is connected to the Colorado River and there is a complex set of state and federal laws that govern its use.

The applicant has proposed to offset its water use by fallowing surrounding agricultural lands (termed a Water Conservation Offset Program), however staff believes that avoidance of the impact is preferable. Staff evaluated several alternative water supply and cooling technologies and determined that dry cooling in another location would result in no unmitigated significant impacts. Either dry cooling, or wet cooling using Rannells Drain water (part of the Palo Verde Irrigation District's irrigation return system) in conjunction with a verifiably effective WCOP would eliminate or mitigate the project's water supply and groundwater quality issues and are the preferred alternatives.

No significant impacts are expected during the power plant's construction phase so long as proper measures are taken to ensure that impacts from stormwater and sediment are adequately controlled. The use of an evaporation pond is an acceptable wastewater discharge method from a water quality perspective, but may cause problems in **Biological Resources** and may cause impacts to aviation safety as discussed in the **Traffic and Transportation** section.

INTRODUCTION

In this section staff summarizes the potential effects of the BEP II on soil and water resources based on review of a Soil and Water Resources Technical Report prepared by a panel of experts which will be published in May 2005. The analysis specifically focuses on the potential for the project to cause significant 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.

A determination of the conformance of the project with all applicable laws, ordinances, regulations and standards will also be made.

Where actual or potential impacts are identified, staff has recommended either elimination of the impact or mitigation measures to reduce the significance of the impact and, as appropriate, has recommended conditions of certification.

SETTING

REGIONAL SETTING

The proposed project is located in the Palo Verde region of eastern Riverside County, which is part of the greater Colorado River Valley. Palo Verde can be subdivided into two sections, the current flood plain, usually referred to as the Palo Verde Valley, and the upland terraces that flank the valley, called Palo Verde Mesa. The proposed project is located on the Palo Verde Mesa, one mile west of the mesa-valley boundary.

The Palo Verde Mesa covers approximately 280 square miles. The mesa is bounded on the north by portions of both the Little and Big Maria Mountains, on the west by the McCoy and Mule Mountains, and on the south by the Palo Verde Mountains. The Palo Verde Valley forms the eastern boundary of the mesa.

The groundwater system in Palo Verde is predominated by the Colorado River. The Colorado River is a primary agent in creating the groundwater system and is the only significant source of groundwater recharge in the region. Groundwater recharge from precipitation is negligible.

The Palo Verde Irrigation District (PVID) is the sole entity in Palo Verde with rights to divert and use Colorado River water. PVID annually provides irrigation water to approximately 90,000 acres of farmland, primarily in the valley, with water diverted from the Colorado River. A major portion of the water that PVID diverts is consumed by the crops it irrigates. The portion of the applied water that is not consumed by crops percolates past the root zone to recharge the underlying aquifer.

PROJECT, SITE, AND VICINITY DESCRIPTION

East of the property are the Buck Boulevard substation and Blythe Energy Project Phase I (BEP I), a 520-MW power plant, which started turbine testing in summer 2003 and became commercially-operational in December 2003. Beyond the 520-MW power plant facility was a large citrus grove, which has been recently abandoned and trees removed, and the Western Area Power Administration's Blythe Substation. The BEP II project will occupy a 76-acre parcel on the western portion of the BEP I site. The BEP II site is on land that has been designated as Farmland of Local Importance in the Important Farmland Inventory prepared by the California Department of Conservation (BEP II 2002, Section 7.14). However, it has never been irrigated. The wind erosion potential for most of these soils is moderate to high.

There are no significant surface water bodies in the vicinity of the site. Drainage on the Palo Verde Mesa in the vicinity of the site generally flows to the southeast toward the

Palo Verde Valley and the Colorado River. Likewise, the existing topography at the BEP (I and II) site is relatively flat with gradient towards the southeast. Drainage at the 152-acre (BEP I and II) site has been modified to accommodate the BEP II facilities. The drainage plans for the BEP II facilities are intended to prevent the flow of runoff onto the project site from upgradient land. Runoff from upgradient of the project site is captured in a network of drainage channels and routed to the retention basin at the southern portion of the BEP (I and II) site. Runoff generated on-site will also be routed to the retention basin. Runoff caused by major rainfall events will convey eroded soil to the BEP (I and II) retention basin, where the eroded soil would be trapped.

Water Supply

The proposed raw water supply for all plant uses would be from two 3,000 gpm groundwater wells to be constructed on the BEP II site. The BEP I and BEP II project's combined groundwater use would be 6,600 acre-feet/year. The second well on each site is designed to provide backup to the first well. However, during emergencies, both wells on a single site could provide the entire water supply to both projects because the systems would be connected and all wells would have similar capacities as BEP I. The project's water treatment plant will consist of an evaporator (brine concentrator) for concentrating the cooling tower blowdown, a reverse osmosis unit to purify water for potable water use, and an RO unit and an electrodeionization unit for producing demineralized water for the steam production and gas turbine inlet cooling.

The project site is underlain by the Older Alluvium of the Colorado River, the Bouse Formation, and the fanglomerate. Well logs for the BEP I production wells (PW-1 and PW-2) confirm that the aquifer is more than 600 feet thick near the BEP II project site. Both PW-1 and PW-2 have proven to be highly productive wells, and given the proximity of BEP I to the BEP II site, it is reasonable to assume that aquifer parameters are essentially the same at both sites.

There are several agricultural and industrial wells on the mesa and several that provide groundwater to domestic users. Other than the BEP I wells, the closest existing industrial well to BEP II is the Thermal King shop well, located on Hobsonway, about 2,700 feet from the project well sites. The largest domestic well serves the Mesa Verde community which is located 2 miles from the project site (BEP II 2002a, Data Request responses, Figure 64-1). In addition, the applicant reports 10 other domestic wells located between to 2 miles from the proposed project well sites.

Wastewater Discharge

The raw water from the on-site wells is directed to three places: a minor amount to in-plant utility uses, on the order of 5 percent is directed to the gas turbine inlet air cooling system, and the remainder to the steam turbine condenser cooling system (cooling tower). The two larger uses are for evaporation in cooling towers of 7 cycles of concentration. The blowdown/wastewater from the cooling towers is sent to a brine concentrator system. In this equipment approximately 95 percent of the water is flashed off in a vacuum system as pure water, the remaining 5 percent, containing essentially all the dissolved solids, is sent to an evaporation pond. The pure water is then directed to the makeup system for the plant steam process and through the demineralizer system as needed, with the rest of the pure water returned to the main cooling tower.

Wastewater streams from BEP II circulating water processes will be discharged to the BEP II evaporation pond after being concentrated in the brine concentration unit. The concentrated brine will have elevated concentrations of total dissolved solids (TDS) and other non-hazardous constituents (BEP II 2002, Section 7.13; BEP II 2004, Table 3). Wastewater streams from the oil water separator will also be discharged to the evaporation pond (BEP II 2002a, Data Response 68). The wastewater sent to the evaporation ponds can accurately be described as brine, and is actually far "saltier" than ocean water (see also **Biological Resources**). This brine is left exposed to the sun and wind so that the water will evaporate, and in due course (years) all the water will be removed and only the chemical solids that were initially brought in with the well water and any non-volatile power plant water treatment chemicals, will remain. These solids will eventually be removed to a suitable solids disposal site.

Stormwater Discharge

The relatively flat topography at the site naturally drains towards the southeast. The BEP (I and II) site intercepts storm water runoff from a contributing upgradient watershed of approximately 1,134 acres, which will be routed in drainage channels to the retention basin in the southern portion of the BEP (I and II) site. All non-contact runoff generated on the 152 acre BEP (I and II) site will be routed by a network of drainage channels and culverts to the retention basin. The retention basin is intended to capture and percolate all runoff generated by a 100-year 24-hour event and to prevent potential storm water drainage impacts (BEP II 2002, Section 7.13). Storm water drainage from plant process areas will be routed through an oil-water separator and pumped to the evaporation pond. A condition of certification will be proposed to ensure stormwater and erosion impacts are not significant.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Soils

Linear Facilities

As noted in the Transmission Engineering section of the FSA, it is not clear how BEP II will connect to the grid. The applicant did not provide the discussion of the final routes, construction methods, environmental setting, environmental impacts, and mitigation measures specifically requested by staff (BEP II 2003a, Data Responses 203). A complete project description of the final transmission line route and an approved Drainage, Erosion and Sedimentation Control Plan / Storm Water Pollution Prevention Plan (SWPPP) for any transmission line that is directly part of the project will be required as a condition for certification.

Power Plant Site

As required by Colorado River Basin Regional Water Quality Control Board (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 erosion from construction and operation activities. Staff is proposing a condition to require the applicant to develop and implement a site specific Drainage, Erosion and Sedimentation Control Plan for the entire project (including ancillary facilities) that addresses standard

erosion runoff and sedimentation impacts for construction, post-construction, and operational phases. In addition, as part of the conditions of certification for this proposed project, the applicant would be required to provide a complete, site-specific Erosion and Sedimentation Control Plan, and a complete SWPPP for the BEP II site and any shared facilities.

Water Conservation Offset Program

The BEP II project includes a Water Conservation Offset Program (WCOP) intended to offset the project's water use by fallowing agricultural lands within the PVID. The applicant has offered to include the following conservation measures in the WCOP (BEP II 2003, Data Responses 174,198, 225):

- Maintenance of stubble residue for fields previously planted in alfalfa, wheat, barley, or similar crops; and
- Clod tilling for non-irrigated fields without stubble residue or sod cover. Mulch or similar material would be integrated into the clods on soils classified as Highly Erodible Land (HEL) by the Natural Resource Conservation Service (NRCS).

These conservation measures could be adequate on certain soils in the Palo Verde area. Some of staff's concerns with the proposed WCOP stem from inadequacies in erosion control measures. Staff notes that absent a condition requiring the applicant to implement erosion control recommendations of the National Resource Conservation Service (NRCS), that there would not be any assurances that land fallowing would include proper Best Management Practices (BMPs) for erosion control, and therefore could lead to a significant adverse impact to soil resources. Implementation of land management measures that have been reviewed and approved by the NRCS and Palo Verde Resource Conservation District (PVRCD), and included as an integral part of the WCOP would provide adequate mitigation for potentially significant erosion impacts associated with the planned fallowing program.

Beyond the specific concern for erosion control measures, staff believes in a broader sense that the Final WCOP submitted by the applicant has not provided sufficient detail with regard to how it would be implemented, managed, monitored, reported, and verified (BEP II, June 2002). Although staff believes the proposed BEP II WCOP in its current form is inadequate with respect to erosion control measures and its ability to accomplish water conservation, the USBR has indicated its acceptance of the BEP II WCOP (USBR 2002). Staff recommends the Energy Commission review and approve the final WCOP in conjunction with review and comment from the PVID, NRCS, and the USBR to ensure it contains erosion control measures and verifiably conserves water. In the event the Commission desires a Condition of Certification addressing the BEP II WCOP, staff has proposed in the Soil and Water Resources Technical Report a Condition of Certification that would address the inadequacies of the proposed WCOP.

Surface Water Hydrology

The BEP II site is not located near any natural surface water features and is not within a 100-year floodplain. The BEP II site will be graded to direct surface water runoff to an on-site retention basin designed to accommodate a 100-year storm and prevent runoff from leaving the site. As part of Conditions of Certification, staff has recommended

revisions to the retention basin operational plans to address the need for mitigation of potentially significant adverse flood related impacts.

Groundwater

The only significant source of groundwater recharge to the BEP II wells would be water derived from the Colorado River. Project pumping would induce groundwater recharge from PVID's Rannells Drain, which is located about one mile east of the project site. In addition, PVID irrigation delivers water to about 2,000 acres of farmland on the mesa and this provides a small steady source of groundwater recharge (PVID 2004).

Static groundwater levels at the BEP II site will decline as BEP I wells reach full production. BEP I has projected that the average long-term pumping rate would be approximately 2,040 gpm (3,300 acre feet/year). Based on drawdown calculations reported by BEP I, static groundwater levels at the proposed BEP II well site will decline about 4.4 feet, lowering static groundwater levels to less than 245 feet mean sea level (MSL) at the BEP II site. If static water levels decline below 245 feet MSL, the water levels in the BEP II wells will be below the U.S. Geological Survey's accounting surface, which indicates the BEP II wells would yield water that will be replaced with Colorado River water.

Groundwater pumping for BEP II may cause two potentially significant impacts, well interference impacts to nearby existing wells and water quality impacts.

Well Interference Impacts

Significant well interference impacts occur when a project's pumping causes substantial and unacceptable declines in groundwater levels in existing nearby wells. The applicant provided an initial analysis in the AFC that evaluates well interference impacts that would be caused by project pumping. The nearest well identified by the applicant, the Sun World well (the Thermal King well is actually the closest well) would only experience 2.2 feet of drawdown, according to the applicant's analysis. Staff has determined that the applicant's well interference analysis is in error and staff has provided an alternative analysis.

The calculated well interference caused by project pumping would average 3.8 feet, increasing to 4.5 feet during maximum-rate pumping. Therefore, staff concludes that project pumping would not produce sufficient well interference to damage pumps in any known, pre-existing wells (excluding the BEP I wells). BEP II pumping would produce about 4.4 feet of drawdown on BEP I's wells, increasing to about 5.4 feet during maximum-rate pumping. Staff concludes that the BEP II well interference would be likely and would cause adverse impacts in terms of increased lift costs to large groundwater producers on the mesa near the project.

The applicant accepts the Conditions of Certification Soil and Water 6 and 7 that were required for BEP I, which is related to well interference impacts (BEP II 2003, Response to Data Request 199). In addition, the applicant supports conditions that included on-site aquifer testing on project production wells, calculation of well interference from the aquifer test results and reimbursement of existing well owners for impacts.

Water Quality Impacts

Staff identified three potential adverse impacts related to groundwater quality that could be caused by the proposed project. First, impacts may be produced from chemical constituents in groundwater that would be concentrated and volatilized during the cooling process. Staff concluded that the potential for significant adverse impacts posed by the hazardous chemicals previously detected in groundwater on the BEP I property would also apply to BEP II, given the proximity of the project wells to BEP I.

Second, project groundwater pumping could mobilize hazardous chemicals in the subsurface causing the occurrence of chemical concentrations in the project wells or in existing private wells. The applicant's contaminant investigation did not identify any significant unmitigated contamination sites near the project. Staff concludes there is no evidence of an unmitigated source of groundwater contamination that could be affected by project pumping, but it is a potentially significant adverse impact. To confirm it never becomes a significant impact, staff proposes a Condition of Certification in the Soil and Water Resources Technical Report to monitor groundwater quality.

Third, project pumping would probably cause upwelling or transport of groundwater with higher concentrations of naturally occurring minerals, causing degradation of groundwater quality. Although groundwater concentrations approach and, in some cases, exceed the upper limits for secondary drinking water standards for total dissolved solids (TDS), specific conductance and chloride, it is a source of drinking water and the only source of fresh water available in the Palo Verde Mesa. Multiple-year sampling data for both deep and shallow wells on the mesa demonstrate an increase in TDS with time; of these wells located near the project, increases in TDS have been significant. Based on water quality sampling in the BEP I wells, some degree of groundwater degradation may have already occurred in the vicinity of the proposed project from prior groundwater production for BEP I.

For BEP II, the applicant has proposed to construct two 600-foot deep, high-capacity wells on the mesa (one primary well and one back-up well). The proposed project wells would approach or penetrate the Bouse Formation. Brackish water from the Bouse Formation has slowly diffused into the fresh water of the mesa aquifer over time. Deep, high-rate production wells would be likely to increase the draw-up of brackish water from the Bouse Formation and cause degradation of the fresh-water aquifer. Given the vulnerability of the aquifer system to degradation, the irreversibility of the process and the lack of an existing alternative water supply system on the mesa, staff concludes that the proposed project groundwater pumping is likely to produce direct significant and unmitigable impacts to groundwater quality.

Staff recommends that BEP II replace proposed groundwater use with either dry cooling or with agricultural return water, obtained directly from PVID's Rannells Drain. Either of these alternatives would mitigate the potentially significant impact of irreversible groundwater degradation that would be caused by project groundwater use. With the implementation of either alternative, no significant impact to groundwater quality would occur.

Water Use at Power Plant

Based on the applicant's Revised Project Description as provided in April 2004, staff's water use estimate is 3,262 acre-feet/year. Staff's calculation is sufficiently consistent with the applicant's stated expectation of 3,300 acre-feet/year. To the extent that the power plant is operated in combined cycle mode – without auxiliary firing – or ambient temperature is below expectations, or operation is less than 100% of the year, then less water should be consumed. Staff has recommended a condition to monitor the annual water consumption at the power plant and would propose an annual cap on water use to detect and prevent significant impacts.

In order to consider options for minimizing the water use at the power plant and mitigate significant impacts, staff analyzed several water supply and cooling alternatives in detail in comparison to the proposed project as presented in the Soil and Water Resources Technical Report's Appendix A - Water Supply and Cooling Options Study.

Water Discharge at the Power Plant

The applicant submitted a Waste Discharge Permit Application and submitted a Revision to Information in Support of a Report of Waste Discharge to the RWQCB in February 2004. The RWQCB issued Draft Waste Discharge Requirements (DWDRs) for BEP II on July 9, 2004 (RWQCB 2004). The DWDRs included requirements for leak detection and evaporation pond capacity that reflected the project design presented in the revised Report of Waste Discharge (BEP II, February 2004). The RWQCB also issued a Monitoring and Reporting Program with the DWDRs that outlined requirements for groundwater, vadose zone, and leak detection monitoring and reporting to ensure that potential leaks are identified and repaired before leading to significant impacts to soil or water quality (RWQCB 2004). In support of staff's concerns for the adequacy of area and storage capacity in the Evaporation Pond , the Energy Commission staff submitted comments on the DWDRs in January 2005 requesting that regular monitoring of solids storage depth and water levels be added to the Monitoring and Reporting Program to ensure that maximum operating levels are not exceeded (CEC, January 2005).

Absent the significant adverse effects to wildlife that would result from the Evaporation Pond (see **Biological Resources**), staff would also specify the RWQCB's recommended monitoring requirement for solids storage depth and water levels in a Condition of Certification. There would also be Conditions of Certification regarding the WDRs and reporting requirements to the RWQCB. Staff anticipates that if BEP II operates the evaporation ponds in accordance with the Final WDRs issued by the RWQCB, there would be no significant impacts to soil or groundwater resources due to leaks in the pond liner. However, staff is not recommending a condition addressing compliance with the Final WDRs for the Evaporation Pond, since the pond would cause significant adverse effects to wildlife as identified in **Biological Resources**. If the significant impacts to wildlife can only be mitigated with elimination of the Evaporation Pond, and instead implementation of a Zero Liquid Discharge (ZLD) System, then a Condition of Certification would not be necessary because mitigation was considered specific to the Evaporation Pond.

Sanitary wastewater will be managed and discharged via an on-site septic system and drain field to be designed according to applicable City and County laws. With the implementation of a Condition of Certification which requires compliance with City and County laws, no water quality impacts are expected from operation of the drain field.

Stormwater discharge

Storm water drainage at the BEP (I and II) site will be managed through a network of drains, pipes, channels, and culverts. Non-contact runoff from the project site and upgradient land is routed to the existing retention basin in the southeast corner of the site. Contact runoff from plant process areas will be routed to the oil water separator and then to the evaporation pond. The drainage channels and culverts were designed to convey 100-year peak flows, and to keep contact runoff separate from non-contact runoff. The drainage channel and culvert designs were reviewed and approved by City of Blythe building officials and BEP I's Chief Building Officer. Staff reviewed the drainage channel and culvert designs and found them to be acceptable.

The applicant submitted the BEP (I and II) drainage and retention basin design plans for staff review in Data Response #164 (BEP II 2003) and a set of supplementary storm drainage calculations in February 2005 (BEP II, February 2005). The applicant identified the area of the contributing watershed as 1,273 acres including the BEP (I and II) site and upgradient land. The 100-year 24-hour rainfall was identified for the Blythe area as 3.79 inches. A properly designed and maintained stormwater drainage system is essential to prevent potentially significant impacts to soil and water resources. Staff has yet to receive recognition by the applicant of the as-built capacity of its retention basin and the limited ability to accumulate sediment without compromising needed water storage capacity. Therefore, staff is recommending that the applicant accurately represent its comprehensive plans for permanent stormwater facilities, maintenance and monitoring in the Drainage, Erosion and Sediment Control (DESCP) Plan.

Based on staff's own analysis, staff believes that the proposed retention basin has sufficient capacity to handle the 100-year 24-hour design storm identified by City of Blythe requirements provided that percolation rates can be maintained at the rates measured during the pumping/percolation tests. Ideally, the storage volume provided in the retention basin would be sufficient to provide a higher safety factor within the 2 to 10 range, but a safety factor of 1.8 approaches the acceptable range.

Given the limited capacity of the retention basin, sediment should be removed from the retention basin when a maximum of 0.5 feet (2.12 acre-feet at elevation 317.5 feet) of deposited sediment accumulates at the base of the basin. Staff anticipates that no significant adverse impacts will result from an extreme storm event, provided that sediment is not allowed to accumulate above elevation 317.5 feet. Although design of the retention basin is fully the responsibility of the applicant, staff recommends that the applicant consider employing sediment forebays at culvert discharge locations within the retention basin as detailed in the California Storm Water Best Management Practice Handbook (SWQTF 1993). Sediment forebays would provide a location where sand and heavier silt particles would deposit and would help to limit the area required to remove accumulated sediment.

A small outlet/overflow structure on the retention basin would limit the potential for significant adverse impacts related to uncontrolled discharges or over topping during extreme events. The BEP I retention basin has a 18-inch culvert that would allow discharge of overflows from the basin. In addition along the northern portion of the retention basin where the drainage channels enter the basin, there is a low point in the containment berm that would serve as an outlet to prevent overtopping during an extreme event. Any discharges from the retention basin during extreme events would be negligible as compared to the pre-construction discharges from the BEP (I and II) site including the upgradient, contributing watershed. Staff anticipates that no significant adverse impacts would result from discharges during an extreme event and no mitigation is required.

Staff has recommended several Conditions of Certification in the Soil and Water Resources Technical Report to prevent impacts to soil and water resources associated with managing stormwater as follows:

- Requires the project owner to operate under the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity, and to prepare and implement a SWPPP for Construction in accordance with the SWRCB's standards;
- Requires the project owner to prepare and implement a Drainage, Erosion and Sedimentation Control Plan for both the construction and operation phases of the project in accordance with the Energy Commission's standards;
- Requires the project owner to operate under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity, and to prepare and implement a SWPPP for Operations in accordance with the SWRCB's standards;

CUMULATIVE IMPACTS AND MITIGATION

Groundwater

Groundwater pumping for BEP II would reduce flows in the Colorado River because pumping for BEP II would yield water that would be replaced by Colorado River water from PVID drains and canals. Pumping and drawdown from the BEP I wells has had a similar effect on PVID. Groundwater consumption by BEP I and BEP II would be additive. The proposed use of Colorado River derived groundwater by the BEP II project would not be recognized under a legal entitlement to Colorado River water from the perspective of the Colorado River Board (CRB), since there would not be a water supply agreement with PVID who serves as the local purveyor with legal entitlement to Colorado River water. CRB feels that a verifiably effective WCOP could address its concerns if it were to result in no net increase in Colorado River water use by the project.

In the absence of a verifiably effective WCOP, groundwater use by BEP I and BEP II would cause an average increase of 6,600 acre-feet/year in PVID's consumptive use of Colorado River water. Over the 30-year life of the two projects, BEP I and BEP II would cause a cumulative increase of about 200,000 acre/feet in PVID's consumptive use of Colorado River water. This increase in water used within PVID's service area would

effectively reduce the Colorado River supplies to Coachella Valley Water District (CVWD) and Metropolitan Water District (MWD).

The implementation of either dry cooling, or wet cooling using Rannells Drain water in conjunction with a verifiably effective WCOP would eliminate or mitigate the project's water supply issue and are the preferred alternatives. The alternative use of Colorado River water derived from PVID's Rannells Drain could be recognized under a legal entitlement from the perspective of CRB because BEP II's water supply would be secured under a water supply agreement with PVID, and would be accounted for directly, rather than indirectly as will be the case with groundwater pumping. Otherwise, the project groundwater pumping creates an unmitigated potentially significant cumulative impact to the State's Colorado River water supply and its users. California's Colorado River Water Use Plan (CRB 2000), a constantly evolving effort to end the State's dependence on surplus river flows and reduce consumption to it's allocation of 4.4 million acre-feet per year as amicably and fairly as possible, has as a principal tenet "…core cooperative water conservation/transfers from agricultural to urban use …" (CRB 2000). The project's unmitigated use of this same water supply would unnecessarily further reduce the volume of agricultural water available for transfer.

The drawdown caused by groundwater pumping for BEP II and BEP I is additive and is, therefore, roughly double the well-interference impact of BEP II alone. The combined drawdown increases the potential for the project to cause damage to nearby existing well pumps. Staff concludes that the BEP II project pumping would cause significant impacts to wells within about 3 miles from the project site on the Palo Verde Mesa, based on a significance criterion for well interference of 5 feet drawdown. However, water levels in wells located in the Palo Verde Valley would not be affected because PVID irrigation maintains high water levels in the valley. PVID drains and unlined canals located at the toe of the mesa would provide sufficient groundwater recharge to the BEP II wells that drawdown would be prevented from extending into the valley.

In the event the Commission permits wet-cooling with groundwater, well owners of small-capacity wells would need to be compensated for the cost for lowering pump bowls if needed, owing to either direct or cumulative project impacts.

State Water Supply

The project's proposed unmitigated use of fresh water would add approximately 3,300 acre-feet per year of new demand on California's fresh water resources; this is in addition to the existing BEP I project's use of the same amount of fresh water. Because of the relationships between all of California's water users, and the presumption that California will see major water supply reductions from the Colorado River, BEPII's proposed use of Colorado River water could result in a potentially significant cumulative impact to users of this resource.

Article X, section 2 of the California Constitution requires that water resources of the State be put to beneficial use to the fullest extent possible and states that the waste, unreasonable use, or unreasonable method of use of water is prohibited. The State Water Resources Control Board passed a resolution based on this which states their policy 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. (SWRCB Resolution 75-58). This policy is also in the Energy Commission's 2003 Integrated Energy Policy Report which states that the "Energy Commission will approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative water supply sources and alternative cooling technologies are shown to be 'environmentally undesirable' or 'economically unsound.'" Thus, it is clearly the policy of the Energy Commission and State to conserve water to the extent feasible and to promote alternative cooling options for power plants that propose using only fresh water for cooling.

Staff has determined that dry cooling is both technically and economically feasible, even in the desert environment surrounding Blythe. However, because of concerns identified in air traffic safety and potentially in visual resources, dry cooling is not appropriate at the proposed location. However, given the technical and economic feasibility of dry cooling and the state policy to conserve water and avoid use of fresh water for power plant cooling to the extent feasible, staff also does not recommend approval of the proposed project at the proposed site. Allowing a project to use fresh inland water simply because it is sited on a particular parcel that precludes the otherwise feasible use of dry cooling is not consistent with the intent of the State's policies on water use, especially where there are other sites that would meet the project objectives and allow the project to avoid using fresh water.

Water Quality

Groundwater degradation from pumping is a cumulative, irreversible process. As described under direct impacts, project pumping would probably cause upwelling or transport of groundwater with higher concentrations of naturally occurring minerals, causing degradation of groundwater quality. The potential for groundwater degradation in the mesa, caused by pumping, was reported by the USGS 30 years ago.

Although groundwater concentrations in the mesa approach and, in some cases, exceed the upper limits for secondary drinking water standards for TDS, specific conductance and chloride, the groundwater is the only source of fresh water available in the Palo Verde Mesa, and is classified as a source of drinking water by State Water Resources Control Board policy.

Given the vulnerability of the aquifer system to degradation, the irreversibility of the process and the lack of an existing alternative water supply system on the mesa, staff concludes that the proposed project's groundwater pumping is likely to contribute to potentially significant cumulative impacts to groundwater quality.

Staff recommends that BEP II replace proposed groundwater use with either agricultural drain return water purchased from PVID and obtained directly from Rannells Drain, or with dry cooling. Either of these alternatives would mitigate the project's contribution to the potentially significant cumulative impact of irreversible groundwater degradation that would be caused by project groundwater use. With the implementation of either alternative, no significant impact to groundwater quality would occur. However, staff can not recommend approval of the proposed project at the proposed site due to aviation safety concerns.

ENVIRONMENTAL JUSTICE

The purpose of the Environmental Justice screening analysis is to determine whether a minority and/or low-income population exists within the potentially affected area of the proposed site.

Energy Commission staff has determined the potentially affected environmental justice region to be an area within a six-mile radius of the proposed BEP II site. The population within this area totals 12,170. The minority population within this area totals 7,216, or 59.29 percent of the total population. Because the screening analysis shows a greater than 50 percent minority population within the six-mile radius, staff considered an Environmental Justice screening as part of its environmental analysis. Staff also determined that 20.1 percent of the population is below the poverty level.

BEP II is located about two miles from Mesa Verde/Nicholls Warm Springs, a small, unincorporated residential and largely Spanish-speaking community in the Palo Verde Mesa. Residents of this community and the surrounding unincorporated area rely on private wells to pump groundwater for domestic and agricultural use.

Based on the **Soil and Water Resources** analysis, staff concludes that the proposed project could cause a disproportionate significant impact to a minority population if it is approved to use groundwater for cooling. This involves the potential significant direct impact to the community of Mesa Verde/Nicholls Warm Springs and surrounding private well users from the project's groundwater pumping. The proposed pumping would likely cause the upwelling or transport of groundwater with higher concentrations of naturally occurring minerals, degrading the aquifer's water quality.

The FSA concludes that the potential direct impact to local groundwater from BEP II would be mitigated to a less than significant level if the applicant redesigns the project. Specifically, this involves one of two options: 1) redesign BEP II to a dry cooling system; or 2) require BEP II to purchase low quality agricultural drain return water from PVID and implement a verifiably effective WCOP to mitigate the cumulative impact to the regional groundwater system. Implementation of either option would mitigate the potential environmental impact to groundwater as well as eliminate the disproportionate impact to a minority population. However, staff is not recommending approval of the BEP II project at the proposed site due to aviation safety concerns.

COMPLIANCE WITH LORS

The BEP II will be required to secure Waste Discharge Requirements (WDRs) from the RWQCB before discharging wastewater streams to the evaporation ponds. BEP II must comply with WDRs that regulate evaporation pond capacity, wastewater discharge limitations, monitoring, and reporting for industrial (operational) activities. In following these items, the applicant will remain in compliance with LORS.

Staff does not agree with the applicant's analysis used to calculate the capacity and plan operation of the storm water retention basin. Staff has yet to receive recognition by the applicant of the as-built capacity of its retention basin and the limited ability to

accumulate sediment without compromising needed water storage capacity. Staff will need to confirm that correct design calculations for the basin are provided to staff and to the City of Blythe for review and approval, and used in the SWPPPs required by the RWQCB and the DESCP required by the Energy Commission.

The BEP II will be required to secure a Construction and General Industrial Storm Water NPDES permit from the RWQCB before beginning construction of the power plant or any ancillary component. BEP II must comply with the NPDES requirements that regulate storm water effluent limitations, monitoring, and reporting for construction activities and for industrial (operational) activities. BEP II must supply a Notice of Intent to the RWQCB to operate under both General NPDES Storm Water Permits for Construction and Industrial Activities. The applicant must submit copies of the accepted notices for construction and operational storm water discharge prior to site mobilization and prior to operation, as specified in Conditions of Certification and with that will be in Compliance with LORS.

FACILITY CLOSURE

The BEP II project 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 COMMENTS

This section provides a summary of the comments received on the Soil and Water Resources section of the PSA. Responses to these comments are integrated throughout the Soil and Water Resources Technical Report section of the FSA. A detailed “road map” of how each comment is responded to and where in the FSA specific comments are integrated, can be found in the Soil and Water Resources Technical Report.

APPLICANT'S PSA COMMENTS

The following identifies the issues addressed in the applicant's comments to the PSA as transmitted in their letter dated April 15, 2004:

- Utilization of BEP I water quality testing results;
- Specifics of heat balances, water balances and duct firing;
- Project water requirements;
- Water flow data discrepancies;
- Number of wells, interconnection and use;
- Evaporation pond design;
- Storm water drainage area retention basin location and capacity;
- SWPPP for industrial activity;
- Water supply analysis; and
- Analysis of alternative water supplies and cooling methods.

PVID'S PSA COMMENTS

The following is a summary of the issues addressed in the Palo Verde Irrigation District's (PVID) comments to the PSA contained in their letter dated December 19, 2003:

- PVID's water rights;
- WCOP;
- Impact to PVID's water supplies;
- Impact to agricultural economy;
- Mesa irrigated acreage;
- Priority of water use;
- Groundwater recharge;
- Mesa irrigated acreage;
- Recharge from Chuckwalla Valley;
- Source of recharge to BEP II wells;
- BEP II's Proposed Use of Water;
- PVID Impacts; and
- Use of Colorado River water.

COLORADO RIVER BOARD'S PSA COMMENTS

The following is a summary of the issues addressed in the Colorado River Board's (CRB) comments to the PSA:

- Current status of the Colorado River water supply;
- Valid water contract required for BEP II pumping;
- Lower Colorado Water Supply Project;
- Impact of unauthorized use;
- Impact to Metropolitan Water District (MWD) and Coachella Valley Irrigation District (CVID);
- Quantification of unauthorized groundwater use;
- Lower Colorado Water Supply Project;
- Acceptability of Water Conservation Offset Program (WCOP); and
- WCOP validation and PVID position on WCOP.

CONCLUSIONS AND RECOMMENDATIONS

Staff's conclusions and recommendations are in recognition that there is an unmitigated significant adverse impact to aviation safety common to the proposed project and any alternative water supply and cooling method considered at the proposed BEP II site. Therefore, implementing staff's recommendations for mitigating potentially significant adverse impacts to soil and water resources may also be subject to mitigating aviation safety impacts as well as potential significant adverse impacts associated with other resources and unique to a particular alternative water supply and cooling method analyzed.

1. BEP II's proposed groundwater pumping would likely cause two significant adverse impacts to groundwater quality. First, the project's proposed use of deep, high-capacity wells on the mesa would likely cause some degree of upwelling of brackish water from the deeper Bouse Formation into the shallower fresh water zones, irreversibly impacting the quality of the groundwater supply for all uses on the Palo Verde Mesa. Second, low levels of hazardous chemicals in groundwater were detected on the BEP I property. Based on the potential for concentration and volatilization of these chemicals, the BEP I Final Decision adopted a condition requiring annual groundwater monitoring. Given proximity of the BEP II project wells to BEP I, the same potential would exist for BEP II.

2. The potential significant adverse impact to groundwater quality can be mitigated by BEP II avoiding groundwater pumping and using dry-cooling or utilizing as its water supply agricultural drain return water from PVID's Rannells Drain with wet cooling.

3. PVID's sole source of water supply is from the Colorado River, according to its entitlement as specified under contract with U.S. Bureau of Reclamation (USBR). PVID's water use is accounted for by its diversion from the Colorado River less agricultural drain water returned to Colorado River. The groundwater wells proposed by BEP II would yield water that would be replaced by Colorado River water. Project pumping would induce groundwater recharge from PVID's Rannells Drain, reducing PVID's return flows to the Colorado River.

4. BEP II's proposed use of Colorado River water derived from groundwater, and an alternative for the project to use agricultural return water from Rannells Drain, could have potentially significant cumulative impacts to other users of the State's Colorado River water supply. The unmitigated use of either water supply would effectively reduce the amount of Colorado River water available to the state. This could effectively reduce supplies to Coachella Valley Water District (CVWD) and Metropolitan Water District (MWD) resulting from increasing the quantity of water used within PVID's service area attributable to BEP II.

5. BEP II's implementation of dry cooling, or wet cooling using agricultural drain water together with a verifiably effective Water Conservation Offset Plan (WCOP) , could mitigate the potentially significant cumulative impact to other users of the State's Colorado River water supply by avoiding any net increase in water use within PVID's service area attributable to BEP II.

6. Consistent with state water policy, BEP II's use of agricultural drain return water from Rannells Drain would utilize the most degraded source of water supply reasonably available to the project.

7. Dry cooling and a zero-liquid discharge to solids system would achieve the maximum conservation of water compared to the proposed project and other alternatives. Dry cooling would reduce annual water use from 3,300 acre-feet/year to about 100 – 150 acre-feet/year, and avoid the need for a WCOP, which has associated potentially significant adverse impacts resulting from land fallowing due to soil erosion if not properly implemented.

8. The proposed use of Colorado River derived groundwater by the BEP II project would not be recognized under a legal entitlement to Colorado River water from the perspective of the Colorado River Board (CRB), since there would not be a water supply agreement with PVID who serves as the local purveyor with legal entitlement to Colorado River water. CRB feels that a verifiably effective WCOP could address its concerns if it were to result in no net increase in Colorado River water use by the project.

9. The alternative use of Colorado River water derived from PVID's Rannells Drain could be recognized under a legal entitlement from the perspective of CRB because BEP II's water supply would be secured under a water supply agreement with PVID, and would be accounted for directly, rather than indirectly as will be the case with groundwater pumping.

10. California's Colorado River Water Use Plan (CRB 2000), a constantly evolving effort to end the State's dependence on surplus river flows and reduce consumption to it's allocation of 4.4 million acre-feet per year as amicably and fairly as possible, has as a principal tenet "…core cooperative water conservation/transfers from agricultural to urban use …" (CRB 2000). The project's unmitigated use of this same water supply would unnecessarily further reduce the volume of agricultural water available for transfer.

11. Staff recommends that BEP II use either dry cooling or agricultural drain water from Rannells Drain with wet cooling in conjunction with a verifiably effective WCOP; however, staff can not recommend approval of the BEP II project at the proposed site due to aviation safety concerns.

REFERENCES

BEP II (Blythe Energy Project Phase II). 2002. Blythe Energy Project Phase II Application for Certification (02-AFC-1), Volume 1 & Appendices, Caithess Blythe II, July, 2002.

BEP II. 2002a. Blythe Energy Project Phase II Response to Data Requests #1-102, Caithess Blythe II, March 14, 2002.

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BEP II. 2003a. Blythe Energy Project Phase II Response to Data Requests #189 – 235, Caithess Blythe II, June 13, 2003.

BEP II. 2004. Blythe Energy Project Phase II Application for Certification (02-AFC-1), Section 2.0 Project Description, Caithess Blythe II, April 15, 2004.

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RWQCB. 2004. Draft Waste Discharge Requirements for the Blythe Energy Project Phase II. Regional Water Quality Control Board, Colorado River Region. July 2004.

SWQTF (Storm Water Quality Task Force). 1993. California Storm Water Best Management Practice Handbooks. March 1993.

USBR (U.S. Bureau of Reclamation). 2002. Letter to Terry O'Brien of the CEC from Robert W. Johnson of the USBR, June 14, 2002, Subject: Blythe Energy Project Phase II, Well Water Use and Proposed Voluntary Water Conservation Offset Program.

TRAFFIC AND TRANSPORTATION

Testimony of James Adams, Dale Edwards and Bill Arnold

INTRODUCTION

The Traffic and Transportation section of the Final Staff Assessment (FSA) addresses the extent to which the Blythe Energy Project Phase II (BEP II) may impact the transportation system in the local area. This analysis includes the identification of the roads and routings which are proposed to be used for construction and operation; potential traffic-related problems associated with the use of those routes; the anticipated encroachment upon public rights-of-way during the construction of the proposed project and associated facilities; the frequency of trips and probable routes associated with the delivery of hazardous materials; and the possible effect of project operations on local airport flight traffic.

The influx of large numbers of construction workers can, over the course of the construction phase, increase roadway congestion and also affect traffic flow. In addition, the transportation of large pieces of equipment can impact roadway congestion and safety. Potential impacts related to traffic operations and safety hazards resulting from the construction and operation of the project are discussed below.

Refer to the **PROJECT DESCRIPTION** section of this FSA for a more detailed description of the project.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

Federal, state, and local laws, ordinances, regulations and standards (LORS) that are applicable to the proposed project are listed below.

FEDERAL

The federal government addresses transportation of goods and materials in Title 49, Code of Federal Regulations:

- Title 49, Code of Federal Regulations, Sections 171-177, governs the transportation of hazardous materials, the type 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 Regulations, addresses safety considerations for the transport of goods, materials, and substances over public highways.
- Title 49, Code of Federal Regulations, Section 44718 and Title 14, Code of Federal Regulations, part 77, addresses hazards to air navigation.
- Title 14, Code of Federal Regulations, Section 77.1 et seq., requires an Applicant to notify the Federal Aviation Administration (FAA) of any construction or alteration of more than 200 feet from grade into navigable airspace.

STATE

The California Vehicle Code and the Streets and Highways Code contain requirements applicable to the licensing of drivers and vehicles, the transportation of hazardous materials, and rights-of-way. The California Health and Safety Code address the transportation of hazardous materials. Specific provisions include:

- California Public Utility Code section 21402 states that no use shall be made of the space above the land and waters of the State of California which would interfere with the right of flight.
- California Public Utility Code section 21403(c) explains that "[t]he right of flight in aircraft includes the right of safe access to pubic airports, which includes the right of flight within the zone of approach of any public airport without restriction or hazard."
- California Vehicle Code, section 353 defines hazardous materials. California Vehicle Code, sections 31303-31309, regulate the highway transportation of hazardous materials, the routes used, and restrictions thereon;
- California Vehicle Code, sections 31600-31620, regulate the transportation of explosive materials;
- California Vehicle Code, sections 32000-32053, regulate the licensing of carriers of hazardous materials and includes noticing requirements;
- California Vehicle Code, sections 32100-32109, establish special requirements for the transportation of inhalation hazards and poisonous gases;
- California Vehicle Code, sections 34000-34121, establish special requirements for the transportation of flammable and combustible liquids over public roads and highways;
- California Vehicle Code, sections 34500, 34501, 34501.2, 34501.3, 34501.4, 34501.10, 34505.5-.7, 34506, 34507.5, 34510, and 34511, regulate the safe operation of vehicles, including those which are used for the transportation of hazardous materials;
- California Health and Safety Code, section 25160 et seq., address the safe transport of hazardous materials;
- California Public Resource Code, section 21096, et seq., requires that lead agencies must use the Airport Land Use Handbook as a "technical resource" when assessing airport-related noise and safety impacts of projects located in the vicinity of airports.
- California Vehicle Code, sections 2500 to 2505, authorize the issuance of licenses by the Commissioner of the California Highway Patrol for the transportation of hazardous materials including explosives;
- California Vehicle Code, 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, it requires the possession of certificates permitting the operation of vehicles transporting hazardous materials;
- California Streets and Highways Code, sections 117 and 660 to 672, and California Vehicle Code sections 35780 et seq., require permits for the transportation of oversized loads on county roads; and

- 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.

LOCAL

Riverside County

General Plan Circulation Element

Although the BEP II project facilities would be located entirely within the City of Blythe, possible construction traffic routes include roads in the unincorporated area of Riverside County. Therefore, Riverside County LORS related to traffic and transportation are included. The Circulation Element of the Riverside County General Plan establishes level of service (LOS) C as a Countywide target on all County-maintained roads and conventional State Highways, except that LOS D could be allowed in urban areas only at intersections of any combination of Major Streets, Arterials, Expressways, or conventional State Highways within one mile of a freeway interchange and at freeway ramp intersections in instances where LOS C is deemed to be impractical (Riverside County 1991).

Congestion Management Plan

State-mandated Congestion Management Plans (CMPs) were established in 1990, with the Riverside County Transportation Commission designated to implement the CMP for the region, including the Blythe area. The CMP directs local agencies (e.g. Riverside County and the City of Blythe) to maintain minimum level of service (LOS) thresholds.

Blythe Airport Comprehensive Land Use Plan

The Blythe Airport Comprehensive Land Use Plan (CLUP) is a land use plan to promote safe and continued operation within two miles of the Airport.

Riverside County Airport Land Use Compatibility Plan

Policy Objective 4.2.1 of this plan states that the intent of land use safety compatibility criteria is to minimize the risks associated with an off airport aircraft accident or emergency landing.

City of Blythe General Plan Circulation Element

The September 1989 City General Plan contains a Circulation Element required by State law. The following Circulation Element goals, objectives, and policies are pertinent to the proposed power plant:

Transportation Demand Management Goal: To promote the use of non-single occupant modes of transportation, and to shift trips out of current peak periods. (City of Blythe 1989, p. III-38)

Objective 3.0 The City shall encourage employers to provide alternative work

weeks and flex-time sufficient to reduce peak period trips by 10 percent (City of Blythe 1989, p. III-39). The following policy is in support of Objective 3.0:

Policy 3.1: The City shall encourage employers to provide 4 day-40 hour and 9 day-80 hour work weeks, and/or provide start/end times outside of the 6-8 a.m. and 4-6 p.m. peak periods of traffic.

Policy 11 Provide and maintain roadway intersection operations at Level of Service (LOS) D or better at peak traffic volumes for all segments of the City's circulation system.

SETTING

The project site is located in the City of Blythe approximately five miles west of the downtown area, 0.25-mile north of Interstate 10 (I-10) within Riverside County in southeastern California. The site is 152 acres in size and is approximately one mile east of the Blythe Airport. **TRAFFIC and TRANSPORTATION Figure 1** shows the area of the project site. The project site is located in the Palo Verde Valley area of the County, in which agriculture is an important economic resource. BEP II would be built on the 76-acre expansion portion of the Blythe Energy Project Phase I (BEP I) site, on the west side of the site.

The entire BEP I/BEP II 152-acre site is to the north of and adjacent to Hobsonway, and to the west and adjacent to Buck Boulevard. Construction of BEP I has been completed with the generation facility operating, and the expansion site is unimproved. Hobsonway serves as the I-10 frontage road in the area and as the business loop for the City of Blythe (BEP II 2002a, p. 7.4-2).

Three highways, Interstate 10 (I-10), State Route (SR) 78 (Neighbors Boulevard) and United States Highway 95 (U.S. 95, Intake Boulevard) provide regional access to the plant site. I-10 is a major four-lane divided, east-west freeway that links the Greater Los Angeles Metropolitan Region eastward through Phoenix and Tucson, Arizona to New Mexico and points east. U.S. 95 is a two-lane, north-south highway that provides access to the City of Blythe via the cities of Vidal and Needles. US-95 is located approximately 6.5 miles east of the BEP II site, and continues north through California into Nevada and on to Las Vegas. SR 78 is a two-lane, north-south highway that provides access to the Palo Verde Valley via the City of Brawley. SR-78 has its western terminus in San Diego County at Interstate 8, and is located approximately 1.5 miles east of the site.

From the west, site access is from the I-10/Mesa Drive interchange located near the airport and Hobsonway. From the east site access is via I-10 at interchanges located at SR-78, Lovekin Boulevard, or US-95, and then on Hobsonway to the site.

Neighbors Boulevard is a two-lane collector road to the south of I-10 (Petritz 2003b). Lovekin Boulevard, near its intersection with Hobsonway, has four lanes, but it soon becomes a two-lane road north and south of Hobsonway. Intake Boulevard has two

lanes. Lovekin and Intake Boulevards are arterial roads (City of Blythe 1989). **TRAFFIC and TRANSPORTATION Figure 2** (BEP II 2002a Figure 7.4-2) shows the project site vicinity.

AIRPORT

The Blythe Airport is located approximately one mile west of the proposed BEP II site off of Hobsonway. The airport is outside the current boundary of the City of Blythe and is located in unincorporated Riverside County. The airport property includes the planned Blythe Airport Industrial Park area. Blythe Airport is owned by Riverside County, which contracts with the City of Blythe for operations.

Regional access to the airport is from I-10 at the Mesa Drive interchange. The airport is operated as a municipal general aviation facility and provides regional air services (BEP II 2002a, p. 7.4-7). There are two operating runways at Blythe Airport. Runway 8-26 (oriented east-west) is the primary runway and is 6,562 feet long, and 150 feet wide. Runway 17-35 (oriented north-south) is 5,820 feet long and 100 feet wide. The airport can accommodate business jets and transport type aircraft (Coffman 1992, p. 2-1). Flight training companies frequently use this airport. Activity at the airport consists of an average of 67 aircraft operations per day (Air Nav 2002). Aircraft using Runway 8-26, approaching from or departing to the east fly over the BEP II site (Downs 2003). The majority of the take-off and landings use Runway 8-26 (Coffman 2000, p. B-5).

The Blythe Airport Master Plan (2000) is focused on developing and maintaining a long-term development program for the airport. The Master Plan update considers extending Runway 8-26 to 7,000 feet in order to accommodate larger aircraft (Coffman 2000 Table 3C, p. 3-7). The City of Blythe has indicated that any Master Plan proposals for the future extension of airport Runway 8-26 will be to the west only (City of Blythe 2003). This would extend the runway away from the project and from the populated downtown area.

RAILROADS

The Blythe area is served by the Arizona & California (A&C) Railroad which travels through part of the Palo Verde Valley. The railroad line accesses the valley from the northwest and then runs south through the City of Blythe. The A&C line terminates at Ripley, approximately seven miles southwest of the City of Blythe, and operates two days per week. This railroad line is used for transport of rail freight into and out of the Palo Verde Valley. Passenger service is not provided (Scott 2002).

PUBLIC TRANSPORTATION

Local bus service in the greater Blythe area is provided by the Palo Verde Valley Transit Agency. There is a bus stop at I-10 and Mesa Drive about 1.3 miles from the project site. This agency also operates dial-a-ride service for unincorporated areas and in the City of Blythe for seniors and the disabled (Palo Verde Valley Transit Agency 2003). The Greyhound Company provides bus service to major California cities outside of the Blythe region.

BIKE LANES

The City of Blythe encourages the use of walking and bicycling as alternative modes of transportation, and when appropriate, incorporates bicycle and pedestrian facilities into the roadway design process. The City has adopted a non-motorized transportation plan that includes a Class II or III bike lane along Hobsonway in the vicinity of BEP II. Hobsonway currently has no bicycle lanes in the vicinity of the site and none are planned. However, the City's Plan Review Committee has a specific requirement that BEP II accommodate the future installation of a Class II bike lane by including in the site plan sufficient width of pavement on the north side of Hobsonway (Petritz 2003a).

EXISTING TRAFFIC CONDITIONS

Traffic and Transportation Table I (BEP II, 2002a, Table 7.4-1, p. 7.4-4) identifies the existing annual average daily traffic (AADT), hourly highway design capacity, annual average peak-hour traffic, and peak hour LOS for highways in the vicinity of the project. The traffic estimates are presented for various road segments between mileposts or junctions on each highway. Daily and peak hour traffic volumes are illustrated. All street segments shown have a peak hour of LOS A.

LOS levels refer to the average vehicle capacity and the flow of traffic. LOS A denotes free flow of traffic while LOS E and F means that there is a congested flow. The LOS criteria take into account numerous variables such as annual average daily traffic (AADT), lane capacity, grade, environment, and other relevant information. The State-mandated CMP authority in the area of the project site is Riverside County in unincorporated areas and the City within its boundaries. The County CMP's goal is LOS D when practical, and LOS E threshold represents the maximum vehicles per day that a highway or roadway can serve and still meet the minimum acceptable standard on the County roadway system (BEP II 2002a, p. 7.4-9). The City has adopted the County of Riverside CMP requirements. The City's General Plan vehicle capacity goal is also LOS D (City of Blythe, p. III-39). These adopted CMP goals are still valid, although the CMP has not been implemented in and around the City due to the low traffic volumes in these areas (BEP II 2002a, p. 7.4-9).

TRAFFIC AND TRANSPORTATION Table 1
Present Conditions of Affected Roadways

Street Segment	Classification	No. of Lanes	Average Daily Volume[1]	Hourly LOS D Thresh-hold[2]	Hourly Design Capacity[3]	P.M. Peak Hour Volume[4]	Peak Hour LOS
SR-78 S of Interstate10	Arterial	2	2,800	970	1,200	220	A
US-95 N of Interstate10	Arterial	2	5,100	970	1,200	410	A

Interstate10:	Freeway	4					
E of Mesa Dr.			17,100	7,130	8,800	1,650	A
W of Mesa Dr.			16,300	7,130	8,800	1,550	A
E of SR-78			17,100	7,130	8,800	1,650	A
W of SR-78			18,200	7,130	8,800	1,750	A
E of US 95			19,200	7,130	8,800	1,850	A
W of US 95			21,500	7,130	8,800	1,400	A

1—Estimated number of vehicles per day, based on 2000 Caltrans traffic counts.
2—Maximum number of vehicles per hour in one direction of LOS D.
3—Maximum number of vehicles per hour in one direction
4—Peak hour number of vehicles per hour, based on 1998 Caltrans traffic counts.

According to the Application for Certification (AFC), Traffic counts for local roadways are limited or nonexistent as neither the County of Riverside nor the City of Blythe measure traffic flows on roads near the site due to the rural nature and low traffic volume in the area (BEP II 2002a p. 7.4-4). However, a traffic study prepared for the City of Blythe, the Palo Verde Valley Transportation Master Plan (Parsons Brinkerhoff), shows the following LOS values for local street locations important to project construction worker and truck traffic:

TRAFFIC AND TRANSPORTATION Table 2
Year 2000 Traffic Conditions-Mid-Block Count Location 2000 LOS

Hobsonway west of Neighbors	A
Hobsonway east of Defrain	A
Hobson way between Lovekin and Broadway	A
Hobsonway between 7th St. and Intake	A
Intake between Hobsonway and I-10	A
Intake at I-10	A
Intake between I-10 and 14th Ave.	A
Lovekin between Hobsonway and I-10	A
Lovekin at I-10	A
Mesa between Hobsonway and I-10	A
Mesa at I-10	A
Neighbors at I-10	A

Source: Parsons Brinkerhoff 2000

TRAFFIC AND TRANSPORTATION Table 3
Existing Intersection Conditions
PM Peak Hour – Unsignalized Intersections

INTERSECTION	1/28/00 LOS	1/29/00 LOS	5/26/00 LOS
Hobsonway/Intake	A	A	A
I-10 WB ramps/Intake	A	A	A
I-10 EB Ramps/Intake	B	B	B

Source: Parsons Brinkerhoff 2000

As shown in **Table 1**, all highways in the area currently operate at LOS A. **Traffic and Transportation Tables 2 – 4** demonstrate that representative local streets and intersections important to project construction are at LOS A except for one intersection

at LOS B. Staff's 2004 observations of the Blythe area's highway and road network and related traffic levels indicate that LOS level A conditions are still the norm.

The AFC provides accident data from the Highway Patrol (Blythe Station) for I-10, SR-78, US-95 and unincorporated roadways in the vicinity of the project site for a period between 1997 and September 1999 (BEP II 2002a, p. 7.4-6). The data shows that

TRAFFIC AND TRANSPORTATION Table 4
Existing Intersection Conditions
PM Peak Hour – Signalized Intersections*

INTERSECTION	1/28/00 LOS	1/29/00 LOS	5/26/00 LOS
Hobsonway/Lovekin	A	A	A
Hobsonway/7th	A	A	A

Source: Parsons Brinkerhoff p. 3-4
*Signalized intersections are analyzed using Intersection Capacity Utilization (ICU) methodology.

accident rates range from 0.40 to 0.70 accidents per million vehicle miles (MVM) traveled. The 1997 Accident Data on State Highways (BEP II 2002a p. 7.4-6) indicates an average statewide accident rate of 2.4 MVM for roadway types corresponding to I-10 and 1.27 MVM for State Routes corresponding to US-95 and SR 78. The accident rates for the highways near the study area are well below statewide accident averages.

ANALYSIS AND IMPACTS

According to Appendix G of the California Environmental Quality Act (CEQA) Guidelines, a project may have a significant effect on traffic and transportation if the project will:

- cause an increase in traffic which is substantial in relation to the existing traffic load and capacity of the street system (i.e., result in a substantial increase in either the number of vehicle trips, the volume to capacity ratio on roads, or congestion at intersections);
- exceed, either individually or cumulatively, a level of service standard established by the county congestion management agency for designated roads or highways;
- result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks;
- substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment);
- result in inadequate emergency access;
- result in inadequate parking capacity; or
- conflict with adopted policies, plans, or programs supporting alternative transportation (e.g., bus turnouts, bicycle racks).

DIRECT IMPACTS TO ON-GROUND TRAFFIC AND TRANSPORTATION

Facility Construction

The AFC provides an analysis of projected year 2005 traffic conditions plus project construction traffic trips (BEP II 2002a, Table 7.4-6, p. 7.4-5). An analysis of the peak hour forecast plus peak hour employee trips indicates that freeway segments in the area would continue to operate at LOS A. Staff believes that the analysis and projections by the applicant are reasonable. The AFC does not provide an analysis of the impact of project construction traffic on local roads. However, because the Palo Verde Valley Transportation Master Plan shows all local streets and intersections important to the project at LOS A for the near term (i.e., during the next 3-5 years), except for one intersection at LOS B (see **Traffic and Transportation Tables 2-4** above), it is staff's assessment that project construction traffic would not cause LOS values for local streets and intersections to fall below the minimum City and County standards. City staff concurs that project construction would not cause significant impact to local streets (Wellman 2003d). Construction of Blythe I demonstrated that Hobsonway could be utilized for heavy haul loads. Due to the placement and use of use of temporary jump bridges on Hobsonway, transportation of large plant components from the railhead to the BEP site took any where from three to six hours (City of Blythe 2005a), which the City of Blythe considers acceptable. The City's Public Works and Traffic staff does not anticipate problems with a similar approach being used for Blythe II.

Plant Site Workforce and Level of Service

Construction of the generating plant facility would occur over an estimated 18 to 20-month period and would require a peak (three month) construction workforce of 365 workers, assuming a single shift and a 40-hour, five to six day work week. (BEP II 2002a, pp. 7.4-9 and 10). Construction workers commuting from the greater Blythe area would travel west on Hobsonway or travel west on I-10 to the I-10/SR 78 interchange and then on Hobsonway to the site; those workers who live west of the site would travel east on I-10 to the Mesa Drive interchange and then on Hobsonway to the site. Workers from both directions would enter the site from Buck Boulevard. Workforce vehicle trips were calculated based on this data.

The applicant assumes an average automobile occupancy (AAO) of 1.1 persons per vehicle to represent a worst-case construction worker commute scenario (BEP II 2002a, pp. 7.4-11). Using the AAO rate of 1.1 results in approximately 660 daily trips to and from the site with a maximum of 330 vehicle trips during the p.m. peak hour. A worst-case scenario which assumes that all workers would drive individually to the project site would result in 730 daily vehicle trips to and from the site and a maximum of 365 trips from the site during the p.m. peak hour (BEP II 2002a, pp. 7.4-11). This is one possible scenario; however there are alternatives to single occupant vehicle trips such as a higher level of ride sharing that would lower project impact.

Using the traffic pattern assumptions described above, **Traffic and Transportation Table 5** (BEP II 2002a, Table 7.4-6, p. 7.4-15) shows that when the existing low traffic

volume is combined with construction-related vehicle traffic, highways would continue to operate at LOS A.

Construction activity would generally begin before 7:00 a.m. and end by 4:00 p.m., unless flexible work schedules are implemented (BEP II 2002a, p. 7.4-15). During the hot summer months, the work schedule may be adjusted to evening or early morning hours in order to avoid the high temperatures (BEP II 2002a, p. 7.4-15).

Parking and Laydown areas

Parking for construction worker vehicles and the laydown area for construction supplies and equipment would be provided on 76 acres on the western side of BEP II plant site, including 10 acres for additional laydown space on the eastern side of the site. (BEP II 2004)

TRAFFIC AND TRANSPORTATION Table 5
Estimated 2005 Daily and Peak Hour Construction Traffic Volumes And LOS Worst-Case Conditions

Street Segment	No. of Lanes	Daily Volume			P.M. Peak Hour Volume and LOS		
		Background Traffic	Proposed		Background Traffic	Proposed	
			Project Traffic	Cumulative Traffic		Project Traffic	Cumulative Traffic/LOS
South on SR-78 at the Interstate 10 Interchange	2	3,400	50	3,450	265	40	305 A
North on US-95 at the Interstate 10 Interchange	2	6,800	20	6,820	520	10	530 A
East on Interstate 10 at the Mesa Drive Interchange	4	23,080	690	23,770	2,145	325	2,470 A
West on Interstate 10 at the Mesa Drive Interchange	4	22,000	20	22,020	2,050	5	2,055 A
East on Interstate 10 at the SR-78 Interchange	4	25,440	640	26,080	2,180	285	2,465 A
West on Interstate 10 at the SR-78 Interchange	4	23,950	690	24,640	2,275	0	2,275 A

Truck Traffic

Construction of the generating plant would require the use and installation of heavy equipment and associated systems and structures. Heavy equipment would be used throughout the construction period, including trenching and earthmoving equipment, forklifts, cranes, cement mixers and drilling equipment. Project construction would add 25 trucks, or 50 trips, per day during the peak construction truck traffic month. An estimated 4,165 truck deliveries would be made to the plant site over the course of the 18-month construction period, for an average of 11 deliveries per construction working day (BEP II 2002a, p. 7.4-11).

Project construction trucks would follow the same routes as those used for BEP I (BEP II 2002a, p. 7.4-12). Access to the project site would be on I-10, SR-78 (Neighbors Boulevard), or US-95 (Intake Boulevard) to Hobsonway and then to Buck Boulevard which is adjacent to the site (BEP II 2002a, 7.4-10). Project traffic may also access the site directly from Hobsonway (BEP II 2002b, p. Traffic & Transportation 5). I-10 project

truck traffic would access Hobsonway at Mesa Drive coming east and Lovekin Boulevard coming west. I-10, US-95, and Hobsonway presently incur a high level of truck traffic, whereas truck traffic on SR-78 is low. Most project construction truck traffic would use I-10 and US-95 (BEP II 2002b, p. Traffic & Transportation 5). I-10 truck traffic averages about 5,900 trucks per day, or about 39 percent of total traffic on I-10 (BEP II 2002a, p. 7.4-10). Construction truck traffic from BEP II would not significantly alter the LOS values for I-10, SR-78, and US-95 (See Table 5).

The AFC states that since BEP I/BEP II construction would overlap, BEP II would require fewer truck deliveries (BEP II 2002a, p. 7.4-18). City staff has recently expressed a concern that, because BEP I construction has been completed, now there would be no BEP I/BEP II construction overlap, and so the AFC understates truck traffic (Wellman 2003a). Staff agrees that since BEP I is now operating there is no overlap. However, in reviewing truck traffic on a monthly basis (see BEP II 2002a, Table 7.4-9, p. 7.4-20), staff has concluded that overall highway impact of increased project construction traffic is not significant with the adoption of the Traffic and Transportation Condition **TRANS-5**.

Construction Phase Transport of Hazardous Materials and Waste

Deliveries would also include small quantities of hazardous materials to be used during project construction. The applicant has stated that the deliveries of hazardous materials to and from the site would be conducted in accordance with California Vehicle Code Section 31300 et seq. (BEP II 2002a, pp. 7.4-15, 19). The applicant expects less than two hazardous materials trips per day during the construction period (BEP II 2002a, p. 7.4-12).

The AFC does not select a specific truck route for supplying and removing hazardous materials. However, it does note: "Pursuant to Section 31303 of the California Vehicle Code, the transportation of hazardous materials will be on state or interstate highways that offer the shortest overall transit time possible. The CHP has identified I-10, US-95, and SR-78 as roadways to be used in the transportation of designated hazardous materials" (BEP II 2002a, p. 7.4-15). The routes for the transportation of hazardous materials are addressed in Condition of Certification **TRANS-3.**

Construction Traffic Impact on School Bus Safety

The Palo Verde Unified School District bus route follows the routes that the project work force and construction trucks would take. However, school bus stops are at locations where there is sufficient room for buses to pull off the road, so there would be insignificant added risk to school bus occupants from project construction truck traffic (Hernandez 2003). School locations are not on the project construction truck routes or the routes that the majority of the work force would follow. In addition, Hobsonway would be clear of heavy truck traffic by 5 AM so as not to interfere with school bus routes (City of Blythe 2005a).

Oversize and Overweight Loads

Transportation of equipment that would exceed the load size and limits of certain roadways would require special permits from the California Department of Transportation (Caltrans) and the California Highway Patrol. California Streets and

Highways Code, Sections 117 and 660-72, and California Vehicle Code 35780 et seq., require permits for the transportation of oversized loads on State and county roads. By law, Energy Commission certification takes the place of all necessary State, local and regional permits. However, staff typically requires applicants to get in-lieu permits from Caltrans for oversized loads, encroachment and activities within road right-of-ways. Staff has proposed condition **TRANS-1** to ensure compliance with County and Caltrans vehicle size and weight requirements. The applicant has submitted a traffic management plan for the construction period which has the purpose of identifying all requirements necessary so that project construction does not impede normal road operations (BEP II 2002a, p.7.4-12).

The applicant has stated that oversized and overweight deliveries would be by railroad, offloading near Commercial Street in Blythe between Hobsonway and Barnard Street onto trucks, which would proceed west on Hobsonway or I-10 to the project site (BEP II 2002a, p. 7.4-10). Staff has reviewed correspondence from the applicant and the City of Blythe acknowledging that heavy hauls of equipment can use Commercial Street and Hobsonway without interfering with the newly constructed median islands (City of Blythe 2005). As noted earlier, heavy haul loads from railhead to the Blythe I site required from three to six hours which did not result in any traffic problems.

Emergency Access

The Riverside County Fire Department would serve BEP II from any of four stations in the vicinity of the BEP II site; the station nearest the BEP II site is about 1 mile west on Hobsonway (Zimmerman 2003). The County Fire Department has a fulltime staff, and can call on countywide and State resources as the need arises (Zimmerman 2003). The Blythe Ambulance Service would provide emergency medical service. The nearest hospital is Palo Verde Hospital in Blythe, about 5 miles from the project site. Ambulance response time to BEP II would be from 7 to 10 minutes (Watkins 2003). Access for fire and medical services would be along Hobsonway to the site (Zimmerman and Watkins 2003).

Planned Roadway And Transit Improvements

BEP II construction would not require further street improvements (City of Blythe 2005b). Heavy haul loads could use Commercial Street to Hobsonway, or Commercial to Baldwin to North Lovekin Boulevard to Hobsonway. These routes are acceptable to the City of Blythe (City of Blythe 2004)

Operational Phase

Commute Traffic

Operation of the generating plant would require a labor force of 20 full-time employees (BEP II 2002a, p. 7.4-15). A worst case scenario assumes that each employee would drive a separate vehicle to work and that they would make one round trip from home to work per day, generating approximately 40 vehicle trips per day. Adequate parking would be made available for employees on an on-site paved lot. Staff assumes that the majority of the permanent workforce would reside in the greater Blythe area and their preferred route to work would be east along I-10. BEP II operations-related traffic

impacts are considered minimal, representing less than 0.1 percent of existing AADT on I-10.

Truck Traffic

The applicant has estimated that there would be two truck round trips to the site daily, or 4 trips total, during plant operations (BEP II 2003a, p. 7.4-16). If the project switches to zero liquid discharge with a slurry or salt cake, as is recommended by staff as an option to mitigate significant adverse impacts to biological resources, one additional truck round trip would be needed to haul the resultant waste to an appropriate disposal site. This addition to daily traffic will not significantly affect LOS levels.

Transport of Hazardous Materials and Waste

The transportation and handling of hazardous substances associated with project operation can increase roadway hazard potential. Impacts associated with hazardous material transport to the facility can be mitigated to a level of insignificance by compliance with existing federal and State standards established to regulate the transportation of Hazardous Substances (see staff proposed Condition of Certification **TRANS-3**).

The California Department of Motor Vehicles specifically licenses all drivers who transport hazardous materials. 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. Drivers transporting hazardous waste are required to carry a manifest that is available for review by the California Highway Patrol at inspection stations along major highways and interstates.

The California Vehicle Code and the Streets and Highways Code (Sections 31600 through 34510) 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.

The applicant has indicated that the transportation of hazardous materials to and from the site would be conducted in accordance with all applicable LORS for the handling and transportation of hazardous materials.

The handling and disposal of hazardous substances are also addressed in the **WASTE MANAGEMENT, WORKER SAFETY AND FIRE PROTECTION** and **HAZARDOUS MATERIALS** sections of this report.

Roadway Fogging

Staff conducted a roadway fogging analysis to determine the potential for the BEP II project cooling towers to produce ground-hugging plumes on area roadways. The results of this analysis, which used the Seasonal Annual Cooling Tower Impact (SACTI) model, were that the BEP II project is estimated to cause less than one hour of ground-level fogging over a three year period on Hobsonway, and even less for I-10 (see **Attachment B**). This frequency of potential roadway fogging is considered less than significant.

CUMULATIVE IMPACTS TO ON-GROUND TRAFFIC AND TRANSPORTATION

CALTRANS PROJECTS

The analysis of the available capacity of the regional highways and local roads described in this section shows that the regional transportation system serving the BEP II area (along the potentially affected highways) is operating at very efficient levels of service with significant reserve capacity. The three primary highways and the primary local arterial operate at LOS A.

According to Caltrans staff, there will be several minor Caltrans construction and maintenance projects performed on the three highways (I-10, U.S. 95, and SR 78) in the vicinity of the BEP II site that would be used by BEP II construction traffic. Examples of the minor projects are: replacement of a railroad crossing, drainage improvements, and landscaping. A major project is rehabilitating 114 bridges on I-10 between the cities of Coachella and Blythe (Caltrans 2005a). **TRANS-5** would require that the project owner prepare a project construction traffic control plan in consultation with affected local jurisdictions and Caltrans. Because these three highways are now at LOS A, with implementation of **TRANS-5** staff expects that these Caltrans projects would not not result in a cumulative impact in combination with BEP II construction.

PROPOSED IMPERIAL IRRIGATION DISTRICT (IID) TRANSMISSION LINE

The IID has proposed to construct a new 118-mile Desert Southwest Transmission Line Project (DSWTP) from the Western Buck Boulevard Substation to the Southern California Edison's Devers Substation, approximately 10 miles north of Palm Springs. BEP II may connect with the Buck Boulevard substation, which would connect with this new transmission line (see **Transmission System Engineering** section of this FSA for a discussion of this issue). The DSWTP would be constructed within an existing transmission line corridor. The project generally would be constructed parallel to existing major roads, and a majority of dirt access roads already exist (BLM/IID p. 3.10-1). The DSWTP would cross various highways and local roads. IID project construction trucks may use highways that would also be used by BEP II construction trucks; however, staff concludes that given the present low traffic volume on these roads (see BLM/IID Table 3.10-1, p. 3.10-4), there would be no cumulative impact with BEP II construction.

Given the information currently available, staff is not aware of any cumulative impact that the DSWTP could have on airports in the region and aviation safety.

PROPOSED BLYTHE ENERGY PROJECT TRANSMISSION LINE (BEPTL)

In a separate compliance amendment proceeding, Energy Commission staff are also reviewing a proposal to construct a new transmission line from the BEP I power plant Buck Boulevard Substation that would proceed west about 60 miles to the Julian Hinds substation. An alternative line would proceed south about seven miles to the Central

Valley Project Midpoint Substation. These two lines are being proposed by the owners of the existing BEP I facility. BEP II would not create any cumulatively considerable impacts on traffic and transportation.

DIRECT AND CUMULATIVE IMPACTS TO AVIATION SAFETY

PROXIMITY OF BEP II TO BLYTHE AIRPORT

The BEP II site is located approximately one mile east of the Blythe Airport. Blythe Airport is a small, two runway, uncontrolled (no control tower) facility that has about 67-70 takeoffs or landings per day (Riverside County Airport Land Use Compatibility Plan 2004). The airport is a general aviation transport airport designed to accommodate business jets, cargo-type aircraft, light private planes, and flight school training activities. Many inexperienced pilots use the airport for training purposes. Almost all of the aircraft currently using the airport are relatively small one or two engine propeller planes or small business jets.

The Blythe Airport runways are 393 feet above mean sea level (MSL). Runway 8-26 is oriented in a general east-west direction and Runway 17-35 is oriented in a north-south direction. Runways are designed for aircraft to land in either direction. Aircraft landing to the west at Blythe Airport would use Runway 26, which is 260 degrees on the compass. Likewise, aircraft landing in the opposite direction would use Runway 8, which is 80 degrees on the compass. Runway 17-35 refers to its landing directions of 170 degrees and 350 degrees, respectively.

The BEP II site is located approximately 4,450 feet southeast of runway 8-26 at 335 feet MSL (see **Traffic and Transportation Figure 2**). The 130-foot heat recovery stem generators (HRSG) stacks would be about 72 feet higher than the runway and the cooling tower cell's exhaust stacks would be approximately 18 feet below the height of the runway. Runway 8-26 is the main runway, with 75 percent of Blythe Airport air traffic landing toward the west on Runway 26.

Airplane Traffic Patterns at the Blythe Airport

Several factors affect air traffic patterns at an airport. The primary factor is whether a pilot is operating under Visual Flight Rules (VFR) or Instrument Flight Rules (IFR). VFR operating procedures apply when weather conditions permit pilots sufficient time to see a runway for landing and avoid other aircraft in flight or obstacles on the ground. IFR procedures are required when weather conditions do not satisfy VFR requirements, but only instrument rated pilots may fly under IFR conditions. The Blythe airport operates primarily under VFR, although it has a very high frequency omni-directional range (VOR) instrument approach, and an Instrument Landing System (ILS) approach for practice instrument approaches. The ILS is not certified by the FAA and is for training purposes only.

FAA guidelines establish the standard traffic pattern used by pilots under VFR conditions. Standard airplane traffic patterns consist of a generalized routing in the form of an rectangular path leading to and from the runway and an altitude of 800 to 1,000 feet above the airport elevation for small planes. The Blythe Airport traffic pattern

utilizes an altitude of 800 feet above ground level (AGL) for the downwind leg, and 300 feet AGL for final approach. At airports without an air traffic control tower, such as the Blythe airport, pilots can choose to make a straight in approach, as opposed to flying the standard pattern. After takeoff, a pilot can leave the pattern at various points.

When flying a traffic pattern for landing into the wind, the normal procedure for pilots of average single-engine planes is to fly with - to one-mile horizontal separation away from, or to the side of, the runway when flying downwind, parallel to the runway. For takeoffs, the normal procedure is to fly straight ahead until reaching an altitude of at least 400 feet above the airport before making a climbing left turn to stay in the traffic pattern, or continuing to climb and go straight or turn to proceed to another destination.

The airport currently utilizes a left hand traffic pattern, which means that all turns taken once established in the traffic pattern are to the left. In taking-off from the airport using Runway 26, pilots head west, away from BEP I. Depending upon their destination, they may continue west or turn to proceed in any direction. If a pilot were practicing take-offs and landings, the pilot would make a series of left turns to line up for the final approach to Runway 26. Depending on aircraft size and type, this pattern could take the aircraft over BEP II and/or BEP I at approximately 300-500 feet above ground. Small single-engine planes flying a standard pattern would most likely fly over both power plant sites to line up for the final approach to the runway when landing.

Aircraft approaching from the south, southeast, or east for a modified straight-in approach to Runway 26 could fly over BEP I or BEP II. This is because the proposed BEP II is located just south of the extended centerline of Runway 26, and the existing BEP I is partially located directly under the extended centerline of Runway 26. Aircraft approaching from the north or northeast could fly over BEP I but most likely not BEP II. Typically, aircraft in emergencies will fly directly to the nearest runway. Lining up the plane with the runway is a somewhat imprecise process depending on the weather conditions and the pilot's skill level. Therefore, a plane could inadvertently fly over Blythe II. Emergency approaches from the south, southeast and east could fly directly over the BEP II cooling tower or HRSG stacks.

In addition, aircraft on approach to Runway 26 may need to execute a "missed approach." A missed approach occurs when a pilot decides to abort a landing prior to touchdown, either for practice or because the pilot deems the landing too dangerous for any number of reasons. In a missed approach at the Blythe Airport to Runway 26, an aircraft would climb to about 300 feet above the ground, and would then make a left turn just before reaching the beginning of Runway 26. The aircraft would continue turning left and would fly over BEP II at a relatively low altitude (about 300-500 feet above ground).

Switching to a right hand traffic pattern would reduce flights through the BEP II plumes and the Blythe I HRSG stack plumes for aircraft following the pattern. Although a right hand pattern is known as a "non-standard" pattern, it is used fairly often. At least 30 percent of the airports in Southern California have one or more right hand pattern runways. Pattern modifications are made due to terrain, noise or other considerations and are common.

Complaints of Turbulence Over BEP I

Staff has become aware of the potential problems associated with BEP II's proximity to the airport when pilots started to complain about turbulence encountered when flying over BEP I. Since BEP I began operating in mid 2003, staff has received several documented complaints from pilots regarding moderate to severe turbulence encountered when flying over BEP I and attempting to land on runway 26 (see **Attachment A**).

The pilots encountered the moderate to severe turbulence when flying at altitudes ranging from 350 to 1000 feet above ground level in weather conditions that were clear, calm, and relatively cool. Most of the flights were in the morning, and both single and two engine planes were involved. Four of the five complainants were experienced pilots who were concerned enough about the turbulence to notify the airport operator.

After receiving these complaints staff sought to further investigate the potential severity of the turbulence and its implications for impacts resulting from BEP II. Energy Commission staff's aviation safety expert Bill Arnold, an experienced pilot, flew over BEP I on three separate occasions. During these flights, the he experienced moderate turbulence in a twin-engine airplane at approximately 500 feet above ground. There was no warning to the pilot that he was about to experience turbulence. Regarding this flight, Mr. Arnold stated, "If I had been flying a lighter single-engine aircraft the turbulence would likely have been severe."

The creation of turbulence from BEP I is of particular concern because aircraft flying over BEP I are preparing to land on Runway 26 and are relatively close to the ground (typically 300-500 feet above ground level) and traveling relatively slowly (75 to 90 miles per hour). Under worst-case conditions (solo pilot, small plane, flying at or below approach altitude, cool winter night or early morning with little or no wind, power plant at full load), unexpected significant turbulence can cause sudden and severe aircraft attitude changes (such as 90 degree rolls to the left or right). High angle turns at low speed will result in a loss of aircraft lift and altitude. In addition, sudden aircraft attitude changes at night can result in pilot vertigo – the loss of reference to the earth's horizon. This can result in pilots losing their sense of what is up and what is down. At night, this can easily lead to an aircraft accident. This problem is exacerbated if the pilot is inexperienced or the aircraft is experiencing emergency conditions.

Description of Thermal and Visible Plumes Generated by BEP I and BEP II

To better understand the potential frequency and size of the thermal and visible plumes generated by BEP I and BEP II, staff conducted an engineering analysis using the SCREEN3, SACTI, and Combustion Stack Visible Plume (CSVP) models (see **Attachment B** and also **Visual Resources** for more information). Since BEP II is nearly identical in design to BEP I, the potential for thermal and visible plumes will be similar. Because it was not clear from the pilot complaints what specific structure was causing the turbulence, staff modeled the plumes generated by both the cooling towers and the HRSGs.

The factors involved in creating significant plume turbulence include calm wind speed conditions of less than five knots (a knot is 1.15 miles per hour) coupled with ambient temperature below 70 degrees Fahrenheit. These conditions occur approximately 550 hours per year (based on three years of Blythe Airport meteorological data). Plume turbulence may also occur during low wind speeds that are somewhat greater than five knots, but the worst turbulence will occur when winds are dead calm. Significant visible plumes that would be high enough to obstruct air traffic would only be formed under calm conditions where the ambient temperature is fairly low and relative humidity is fairly high. Conditions conducive to creating visible plumes that may extend vertically 500 feet or more occur approximately 50 to 150 hours per year (based on SACTI and CSVP modeling results). The conditions conducive for turbulence and visible plume occurrence overlap and both occur almost exclusively from October through May with the vast majority occurring during the overnight and morning hours (10 p.m. to 10 a.m.).

The BEP II cooling tower is proposed to contain eight cells, each 40 feet tall and 33 feet in diameter. The entire cooling tower structure will be 472 feet long. The cooling tower exhaust temperature will range from approximately 60 to 95 degrees Fahrenheit, depending upon ambient conditions. During low ambient temperature, the maximum difference between the temperature of the exhaust and the ambient air is likely to be 35 to 40 degrees. The velocity of the exhaust is designed to be 8.5 meters per second (1,670 feet per minute or 19 miles per hour). The exhaust temperature from the HRSGs would be around 200 degrees Fahrenheit, and the velocity is designed to be approximately 20 meters per second (3,900 feet per minute or 45 miles per hour) when operating at full load.

Based on the modeling results, staff estimates that the thermal plumes generated by the cooling tower would easily exceed 500 feet above the ground. At this height, under calm cool conditions, the average velocity of the plume would likely be greater than 4.3 meters per second; and at 250 feet above the ground, considering the thermal buoyancy, the plume would have an average plume velocity of almost double that at 8.5 meters per second or greater depending on ambient temperature. Similarly, staff estimates that the thermal plumes generated by the HRSGs would also easily exceed 500 feet above the ground. The average velocity of the HRSG exhaust in calm conditions, neglecting the additional thermal forces, is estimated to be approximately 10 meters per second at 250 feet above the ground. The plumes from the HRSGs are more widely spaced and narrower and would not merge in the same way as the eight adjacent cooling tower cell exhaust plumes; the overall size of the plume, if encountered by an aircraft, would be much smaller than the cooling tower plume and the impact would only be felt momentarily. Thus, the cooling tower is the greater concern for generation of hazardous turbulence.

Analysis of Impacts of Plumes on Aircraft Safety

As stated previously, BEP II thermal and visible plumes would be substantially similar to BEP I plumes. Aircraft contacting the BEP II thermal plume on approach to Runway 26 would be affected in a similar manner to that described previously for the BEP I thermal plume.

While the BEP I and BEP II plumes will not merge to create a single area of turbulence, the combined effect of having two turbulence causing plumes in close proximity, within one mile of the Blythe Airport, on and near the extended runway centerline for Runway 8-26, would have a potentially significant adverse impact on aircraft safety.

Aircraft on approach to Runway 26, depending on weather and power plant operating conditions, could experience turbulence from either or both of the BEP I and BEP II cooling towers and/or HRSG stacks. As described previously, the turbulence from the BEP I power plant can prove hazardous to aircraft. Having two power plants in close proximity would likely increase the duration of the turbulence for aircraft in the traffic pattern. Staff considers the combined effect of the existing BEP I and proposed BEP II thermal plumes to be cumulatively considerable and therefore a significant adverse cumulative impact.

Visible plumes from the BEP II cooling tower, although not expected to occur many hours during the year, still present a hazard to aircraft on final approach to Runway 26 by temporarily obscuring the pilot's view of the airfield, runway and airspace where other aircraft may be operating. For safety reasons, pilots will normally avoid flying through visible plumes which can reduce or eliminate visibility, and particularly when the plume blocks the view of Runway 26. Since plume form and angle may change due to variable factors such as wind direction and wind speed at different altitudes, plume avoidance may not always be a possible when trying to maintain a glide path (descent) for a safe final approach.

On final approach, pilots, besides looking outside for other aircraft and to see where they are going, also need to perform a variety of tasks such as frequently checking the aircraft instruments to ensure proper engine operation, maintaining a standard rate of descent (approximately 500 feet per minute), and possibly communicating by radio with other aircraft in the traffic pattern. Some aircraft may also have retractable landing gear that requires putting the landing gear down during the preparation for landing procedures. Twin engine planes have additional complications in their landing procedures that also require the pilot's attention. Student pilots in particular, and many pilots in general, use written checklists during landing to ensure they do everything required for a safe landing. All of these activities demand the pilot's attention starting at a certain point on the downwind leg of the traffic pattern, or several miles away for straight-in approaches, until and after touchdown on the runway.

In the course of this investigation staff has received comments from the FAA staff and the applicant that the thermal plumes generated by BEP II would be no different than the thermal plumes that naturally occur in the desert (Griffin 2004 and Winn 2005). Turbulence in the desert is created in two different ways: 1) wind causes terrain-derived wave turbulence where wind is directed upward and downward as it crosses obstructions; and 2) solar heating causes thermal turbulence - as the sun heats the terrain, the air above it warms and rises until it cools and then falls back towards the ground resulting in updrafts and downdrafts, experienced as turbulence. Desert turbulence forms when it is windy or hot and builds gradually. Pilots are given warning of the existence of turbulence before they get close to the ground, giving them time to prepare themselves. The velocity of desert thermals ranges from 200 to 400 feet per

minute (1-2 meters per second) to extremes of 1000 to 2000 feet per minute (5.1 to 10.2 meters per second) during extremely hot dry conditions (see **Attachment B**).

The turbulence created by BEP II would be most severe during calm and cool conditions and would be experienced abruptly, giving no warning to allow pilots to prepare. While experienced pilots might be able to handle unexpected turbulence so close to the ground, novice pilots may not be experienced enough to react properly under such conditions resulting in a seriously hazardous situation. Staff considers this to be a potential significant adverse direct impact of the proposed project on aviation safety.

Public Resources Code section 21096 requires lead agencies performing a CEQA analysis on a project situated within airport land use compatibility plan boundaries to use the Airport Land Use Planning Handbook (ALUPH) published by Caltrans Aeronautics as a technical resource to assist in the analysis. The Handbook identifies two factors involved in determining if a project would significantly impact airport safety: 1) whether a particular project would affect the severity of an aircraft accident; and 2) whether a particular project could be the cause of an accident. (ALUPH 9-2) Two aspects of BEP II could contribute to the creation of a hazard to flight: the visible and thermal plumes emanating from the cooling tower and HRSGs, and bird-attracting evaporation ponds.

The Handbook finds that "the risk of bird strikes is most serious along the corridors required for takeoffs and landings," but "the concern extends to elsewhere in the airport vicinity." (ALUPH 9-56) Therefore, the Handbook specifically states that "Any land uses which can attract birds should be avoided, but those which are artificial attractors are particularly inappropriate because they generally need not be located near airports." (ALUPH 9-56) As is discussed in the **Biological Resources** section of the FSA, BEP I's evaporation ponds have been found to attract 40-50 birds. The addition of another evaporation pond for BEP II will only increase the number of birds attracted to the project site, in the direct vicinity of the Blythe Airport and adjacent to the extended centerline of Runway 8-26, thus increasing the hazard to aircraft.

Pilot actions under emergency circumstances are a major determinant of whether an accident will result and, if so, how. The majority of aircraft landing accidents take place on or immediately adjacent to the runway. A common circumstance that can result in an accident on final approach is pilot misjudgment of the aircraft descent rate – which can be exacerbated by poor visibility and tall objects beneath the final approach course. Because low altitudes decrease the chance of successful recovery from unexpected conditions, accidents can be expected to be more common closer to the runway end than at points farther away (State of California 2002). Since Blythe II is less than 5,000 feet from the beginning of Runway 8-26, and aircraft that might fly over the proposed plant could be at low altitude on approach to the runway, a sudden disturbance from the cooling tower plumes could lead to loss of control of the airplane and a subsequent accident.

The Handbook also identifies three basic categories of hazards to flight: 1) obstructions to the airspace required for flight to, from, and around an airport; 2) wildlife hazards, particularly bird strikes; and 3) other forms of interference with safe flight, navigation, or communication (State of California 2002).

Steps Taken to Mitigate BEP I Impacts

On March 18, 2004, staff sent a letter to the Aeronautics Division of the California Department of Transportation (Caltrans Aeronautics) seeking recommendations for reducing the adverse impact caused by BEP I. Staff also contacted the FAA with a similar letter sent on May 20, 2004. Caltrans responded in a letter dated March 24, 2004, with several suggestions including:

- adding a remark to the Airport Facility Directory advising pilots to avoid low-altitude direct overflight of the BEP I power plant;
- adding a similar remark to the Airport Surface Observing System (ASOS); and
- installing a new Instrument Landing System (ILS) on Runway 17 and deactivating the ILS on Runway 8-26.

Before flying to a particular destination, pilots consult the Airport Facility Directory (AFD) to obtain information on specific airports. The AFD contains, among other things, information about hazards surrounding the airport. Based on a staff request, on July 10, 2003, the FAA added a remark to the AFD for the Blythe airport notifying pilots about the potential for turbulence above BEP I and advising that over-flight of the power plant should be avoided. The ASOS is a radio announcement generated at each airport containing important information specific to that airport such as weather and flying conditions. Most pilots are tuned to the station so that they receive this information as they approach the airport. Staff has also requested that the FAA add an announcement to the Blythe Airport ASOS alerting pilots to potential turbulence above BEP I and advising avoidance of the plant.

The ILS allows pilots to land using only the plane's instruments – the pilot does not have any visual contact with the airport. The ILS at the Blythe Airport is used for training and calibration purposes only. The problem with the ILS being located on Runway 8-26 is that it requires pilots using it to fly over BEP I. This can bring the pilots, who are flying on instruments, directly through the thermal plumes. It is staff's understanding that the majority of ILS approaches are flown by aircraft with two pilots. However, given the invisible nature of the thermal plume, the presence of an additional pilot is not an advantage. Were the ILS moved to Runway 17-35, pilots using the ILS would no longer be required to fly low over BEP I, and approximately one-third of the landings would be entirely shifted to this second runway. Staff is currently working with Caltrans Aeronautics, the FAA, the Blythe Airport Manager, and the BEP I owner to implement the movement of the ILS in a compliance proceeding for BEP I.

Coordination with Responsible Agencies

Staff has looked to other agencies more experienced with issues concerning airport safety, such as the Riverside County Airport Land Use Commission and Caltrans Aeronautics, for help in determining the significance of impacts to aircraft safety posed by BEP II.

The Riverside Airport Land Use Commission (RALUC) is responsible for reviewing a proposed project's consistency with the Comprehensive Land Use Plan. On July 18, 2002, the RALUC determined that the BEP II project at the proposed site was

inconsistent with the Blythe Airport Comprehensive Land Use Plan (CLUP). Policy Objective 4.2.1 specifically states that "the intent of land use safety compatibility criteria is to minimize the risks associated with an off airport aircraft accident in the airport vicinity or emergency landing." Thus, inconsistency with the CLUP could imply that safety risks correspond with the project.

The CLUP identifies and defines five safety zones surrounding the airport.(See **Land Use – Figure 4)**. The purpose of these safety zones is to restrict certain development in the vicinity of the airport in order to promote the safety of persons on the ground while reducing risks of serious harm to crews and passengers of aircraft making forced landings in the immediate vicinity of the airport.

The CLUP provides land use compatibility guidelines that apply to each of these zones. BEP II's structures would be located entirely within the Traffic Pattern Zone (TPZ) and the BEP II site itself is within the Extended Runway Centerline zone (ERC) and the Outer Safety Zone (OSZ). The TPZ is the area around the airport that is most frequently flown over by aircraft in the local airport traffic pattern. The CLUP prohibits uses involving, as the primary activity, the manufacture, storage, or distribution of explosives or flammable materials from being sited in the TPZ. "Any use which would generate smoke or water vapor or which would attract large concentrations of birds, or which may otherwise affect safe air navigation within the area" <u>are prohibited in all safety zones</u> (Caltrans 2004). Additionally, the CLUP identifies power plants as having inherent attributes that would cause them to violate these standards. (Coffman 2000)

On July 13, 2004, the Blythe City Council approved a resolution to override the RALUC's July 18, 2002 determination of inconsistency. Public Utilities Code section 21670 et seq allows a city to override an ALUC's determination of inconsistency "after making specific findings that the proposed action is consistent with the purposes of " the statute; namely the protection of "public health, safety, and welfare" by "minimizing the public's exposure to excessive noise and safety hazards within areas around public airports." (Public Utilities Code §§21676.5)

The City's resolution overriding the RALUC does not make any finding regarding consistency with Public Utilities Code section 21670, but instead is primarily focused on the economic benefits of the project. The override is also based on the finding that technical options exist to improve cooling tower plume dispersion and will be incorporated into BEP II. As discussed below, no such options are feasible to mitigate the cooling tower plume's potential impact. One of the conditions of approval identified in the override prohibits any use which would generate water vapor, attract large concentrations of birds, or otherwise affect safe air navigation within the area. BEP II would do all three of these. The proposed wet cooling towers inherently generate water vapor. As shown by BEP I, the evaporation ponds proposed by BEP II will attract concentrations of birds (as many as 40-50 have been seen at the BEP I ponds – see **Biological Resources**). Also, as discussed in this analysis, BEP II will have a significant adverse effect on aircraft safety in the area due to the turbulence generated by thermal plumes emanating from the cooling towers.

Staff has worked closely with Caltrans Aeronautics staff in order to keep them informed of the issue and also request their input. Caltrans Aeronautics has explicitly stated on

several occasions that they do not “recommend construction of the BEP II facility at the proposed location.” It is their opinion that BEP II would ”exacerbate existing concerns identified by pilots using the airport” and that “the focus of compatible land use planning in the vicinity of an airport should not be limited to ‘reducing significant/adverse impacts’, but avoiding them in the first place.” (Caltrans 2004)

Caltrans confirmed that this remains their position in a letter dated March 12, 2005, where they noted that they remain ”…committed to our position that the establishment of an additional power plant (i.e.. BEP II) in the nearby proximity to the end of Blythe’s Runway 8-26 is not conducive to promoting a safe operational flight environment. We see no need to exacerbate an already questionable situation that does not enhance aviation safety. It remains our position that we do not recommend construction of a power plant facility at the proposed location (Caltrans 2005b).” Staff concurs with the concerns raised by Caltrans Aeronautics and the RALUC and believes that the current site is inappropriate for BEP II.

Depending on the judgment and experience of the pilot, there is still a risk that a pilot could encounter moderate to severe turbulence when flying over BEP I if with all of the proposed mitigation in place. With an inexperienced pilot, the displacement of an aircraft from two sets of plumes (BEP I and II) in close proximity could result in a loss of aircraft control. Constructing BEP II at the proposed site would introduce additional plumes that would have another direct adverse impact on airport operations and, when combined with BEP I, would considerably contribute to a significant cumulative impact on air traffic safety that would be greater than the separate impact of each plant. Caltrans Aeronautics staff shares this concern.

Mitigation Measures Analyzed

Staff has worked closely with Caltrans and the FAA to determine if changes could be made to the project that would mitigate the project’s significant adverse impacts to air safety.

The only possible change to the project that staff could find was installing fans to reduce or eliminate the heat recovery steam generators (HRSGs) and cooling tower plumes. Upon further analysis of this option, staff determined that it would not sufficiently disperse the cooling tower plumes to reduce the impact of the plumes to less than significant.

Another option considered by staff, and identified in the City of Blythe’s override, was changing the traffic pattern for Blythe Airport Runway 8-26 and also Runway 17-35 from the current left hand flow to a right hand flow. This change would substantially reduce the number of aircraft flying over the BEP II project, but would have no effect on approach over-flights from the south, southeast and east. The BEP II visible plumes would also be a potential hazard to aircraft in the traffic pattern, on straight-in approaches, and on final approach when winds of sufficient speed from the south pushing the plumes to the north.

The applicant has not proposed or identified any other measures that would mitigate the project’s impacts to airport safety, and neither Caltrans nor Energy Commission staff

are aware of any mitigation or project design that would do so. Therefore, staff concurs with Caltrans Aeronautics' conclusion that it is inappropriate to build another power plant near the Blythe Airport that will compound the existing problem with additional visible plumes, turbulence and birds attracted to the project's evaporation ponds all of which would increase aviation safety hazards.

Linear Facilities

The natural gas pipeline to BEP II will connect with the on-site existing BEP I pipeline (BEP II 2004e, Traffic and Transportation, p. 2). The BEP II electrical connection would be to the Buck Boulevard substation located in the northeast corner of the project site, which may connect with the Imperial Irrigation District's (IID) proposed 118-mile transmission line (see **Transmission System Engineering** section of this FSA for a full discussion of this issue). The potable water line for BEP II may interconnect with the BEP I water supply. If all linear facilities interconnect on-site as presently planned, linear facilities construction would not cause significant impact on local and regional roads and highways.

Potential Hazardous Materials Release

Staff believes that if a hazardous material release occurred at BEP II it could have a significant impact on vehicles using I-10. Alternate routes, such as SR-95 to the north and SR-78 to the south, for trucks and vehicles in case of an ammonia release should be determined after consultation with the project owner, City of Blythe, County of Riverside, Caltrans, and the Highway Patrol (see Condition of Certification **TRANS-5**). In addition, the Blythe Airport operator should be notified if a hazardous release occurs so pilots using the airport can be warned. Staff has determined that the probability of an ammonia release affecting Blythe Airport is 1 in 10,000 (see **Hazardous Materials Management** section of this FSA for further analysis).

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

Title 14, Code of Federal Regulations, Section 77.1, et. seq. requires an applicant to notify the FAA of any construction or alteration of more than 200 feet above grade into navigable airspace. FAA obstruction criteria takes into consideration primarily solid objects such as buildings and towers. BEP II filed applications with the FAA and in response, the FAA has made determinations of no hazard to air navigation related to the stacks. It is important to note that the FAA is limited to evaluating the height of project structures and can only evaluate those structures that exceed the defined Part 77 surfaces. The FAA is not able to consider the impact of non-structural aspects of a project, such as thermal plumes, on aviation safety. As is stated in the Caltrans Handbook, and discussed in staff's analysis, "tall objects in the approach corridors may pose risks even though they do not penetrate the defined Part 77 surfaces. In its evaluation of the HRSG stack height, the FAA found that the proposed structure would not exceed obstruction standards and would not be a structural hazard to air navigation. Based on this evaluation, the FAA determined that marking and lighting the HRSGs

would not be necessary. (BEP II, 2002a Appendix 7.4, and FAA Determinations of No Hazard to Air Navigation). However, the City of Blythe recommends lighting improvements be added to the BEP II stacks similar to those installed on BEP I and consistent with FAA Advisory Circular 70/7460-1J (City of Blythe 2005b). Staff concurs with this recommendation and the applicant has agreed to the lighting improvements (see Condition of Certification **TRANS-8**).

STATE

Public Utilities Code sections 21402 and 21403(c) prohibit any use of land that would interfere with the right of flight. The right of flight includes the right of safe access to public airports including the right of flight within the zone of approach of any public airport without restriction or hazard. (*Drennen v. County of Ventura*, 38 Cal. App.3d. 84 (1974).) BEP II is located in the zone of approach of the Blythe Airport. As discussed above, BEP II's cooling towers would emit nonvisible thermal plumes that would cause moderate to severe turbulence during certain weather conditions. This turbulence could cause a pilot to lose control of the aircraft as it flies over the plant on approach or while executing a missed approach. This interferes with the right of aircraft to fly into the Blythe airport and is inconsistent with the Public Utilities Code.

LOCAL

The City General Plan Circulation Element's relevant goals, objectives, and policies are discussed below:

Transportation Demand Management Goal: To promote the use of non-single occupant modes of transportation, and to shift trips out of current peak periods.

Objective 3.0 The City shall encourage employers to provide alternative work weeks and flextime sufficient to reduce peak period trips by 10 percent. The following policy is in support of Objective 3.0:

Policy 3.1: The City shall encourage employers to provide 4 day-40 hour and 9 day-80 hour work weeks, and/or provide start/end times outside of the 6-8 a.m. and 4-6 p.m. peak periods of traffic.

Discussion: The BEP II Traffic Management Plan does not contain a plan for alternative work schedules and therefore is in conflict with this policy. Proposed Condition of Certification **TRANS-5** would ensure that the project's Construction Traffic Control Plan addresses the need for construction work hours and arrival/departure times outside of peak traffic periods.

Policy 11 Provide and maintain roadway intersection operations at Level of Service (LOS) D or better at peak traffic volumes for all segments of the City's circulation system.

Discussion: Since project construction and operations traffic would not cause peak traffic volumes to be worse than LOS D, the project is not in conflict with this policy.

Riverside Airport Comprehensive Land Use Plan

Policy Objective 4.2.1 "the intent of land use safety compatibility criteria is to minimize the risks associated with an off airport aircraft accident in the airport vicinity or emergency landing."

Discussion: Construction of BEP II at the existing site would add additional risks to aircraft using the Blythe Airport and is inconsistent with this policy objective.

TRANS-2 Requires compliance with requirements regarding encroachment into the public right-of-way.

TRANS-4 Requires compliance with parking standards.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the population of people of color is greater than fifty percent within a six-mile radius of the proposed BEP II power plant (please refer to **Socioeconomics Figure 1** in this Staff Assessment), and Census 2000 information that shows the low-income population is less than fifty percent within the same radius. Based on the traffic and transportation analysis, staff has identified possible unmitigated significant direct and cumulative impacts resulting from the operation of the project that could affect the safety of air traffic. However, staff has no data demonstrating that minority and low-income populations would be disproportionately impacted, and therefore there are no traffic and transportation environmental justice issues related to this project.

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. The minimum design life of the power plant is expected to be 30 years. At least 12 months prior to the proposed decommissioning, the applicant shall prepare a closure plan for submission to the Energy Commission for review and approval. At the time of closure, all then-applicable LORS will be identified and the closure plan will address how to comply with those LORS. The affects of closure of BEP II on traffic and transportation could be similar to those discussed for the construction of the project if the plant is demolished. Closure could create traffic levels associated with demolition that are similar in intensity and duration to those expected during facility construction.

Unexpected temporary closure occurs when the facility is closed suddenly or unexpectedly on a short-term basis due to unforeseen circumstances such as a natural disaster or an emergency. From the perspective of traffic and transportation issues, in the event of temporary facility closure, the applicant would have to comply with all applicable LORS contained in the section of this report regarding transportation permits for hazardous materials and equipment.

Unexpected permanent closure occurs if the project owner closes the facility suddenly or unexpectedly, on a permanent basis. If unexpected closure occurs, the owner remains accountable for implementing the on-site contingency plan. Unexpected closure can occur when the project owner is unable to implement the contingency plan and the project is essentially abandoned. Staff assumes that the facility will either remain idle until such time that new ownership is established, or dismantling of the facility will occur. In any event, the owner will have to secure applicable transportation permits to satisfy the LORS requirements as stated in this report.

In the event of permanent closure, the effects would be similar to those associated with project construction. Permanent closure will involve a peak work period with commuter traffic. In either instance, the roadway systems within the vicinity of the project should be able to handle traffic without significantly affecting the current level of service of the area.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

Commission staff received a letter dated April 16, 2002 from R. Austin Wiswell, Chief, Division of Aeronautics, Caltrans (Caltrans 2002a). The letter discusses several minor discrepancies in the AFC and the possible impact of waterfowl attractants caused by the project. The letter refers to, and includes as an attachment, a letter dated February 28, 2002, from Sandy Hesnard, Caltrans Aviation Environmental Planner, to Jennifer Wellman, Development Services Department, City of Blythe. This letter discusses project inconsistency with the Comprehensive Land Use Plan (CLUP), concerns regarding possible penetration of navigable airspace, and the potential project impact as a wildlife attractant. Staff has discussed the above concerns and other concerns relating to visual and thermal plumes with Caltrans Aeronautics staff.

On July 26, 2002 the Energy Commission received a second letter from Mr. Wiswell to the Energy Facilities Licensing Program (Caltrans 2002b). The letter discusses the same minor discrepancies in the AFC referred to in the first letter, and also discusses Caltrans Division of Aeronautics LORS relevant to BEP II. Staff has included these LORS in the FSA.

In response to a March 18, 2004 letter from the Commission regarding BEP I and II, the Commission received a third letter from Mr. Wiswell, dated March 24, 2004, that outlined mitigation measures to reduce the adverse safety impact from BEP I operations on aircraft using Runway 8-26. These included adding a remark to the Airport Facility Directory advising pilots to avoid low-altitude direct overflight of BEP I, adding a similar remark to the Airport Surface Observing System (ASOS); and installing a new Instrument Landing System (ILS) on Runway 17 and deactivating the ILS on Runway 8-26. Staff is working with Caltrans, the City of Blythe, and the BEP I power plant owner to implement these mitigation measures. A remark advising pilots to avoid low-altitude direct overflight of BEP I has been added to the Airport Facility Directory.

The March 24th, 2004 letter also recommended that BEP II should not be constructed at the proposed site because it would exacerbate concerns identified by pilots using the airport. Staff agrees with this recommendation.

In response to an inquiry from staff, another letter from Mr. Wiswell dated March 11, 2005, was received that reiterated Caltrans Aeronautics position opposing construction of BEP II at the proposed site. Staff agrees with this recommendation.

CONCLUSIONS

1. The project would be consistent with the circulation elements of the County and City General Plans. The project would not have a significant impact on the local and regional road/highway network. During the construction phase, local roadway and highway demand resulting from the daily movement of workers and materials would not increase beyond significance thresholds established by local and state authorities. During the operational phase, increased roadway demand resulting from the daily movement of workers and materials would be minimal.
2. There would be transportation of hazardous materials during construction and operation. There is good road access for the transportation of hazardous materials. With implementation of the proposed conditions of certification, potential problems would not exceed significance thresholds established by the Highway Patrol.
3. Staff agrees with Caltrans Aeronautics that constructing BEP II at the proposed site would exacerbate the existing aviation safety pilot concerns regarding BEP I.
4. Staff also agrees with the RALUC determination that the BEP II site is inconsistent with the Blythe Comprehensive Land Use Plan.
5. The construction of BEP II at the proposed site would further compound safety issues already imposed by BEP I and is inconsistent with safe airport operations at the Blythe Airport (see **Attachment B**).
6. BEP II would generate cooling tower thermal and vapor plumes that would affect aircraft operations at the Blythe Airport and have a significant adverse direct impact.
7. BEP II, in conjunction with the existing BEP I, would have a cumulatively considerable significant adverse impact on aircraft operations at Blythe Airport.
8. The project would not comply with the applicable state and local LORS as discussed above.
9. The mitigation identified for BEP I minimizes but does not remove the risk to pilots encountering moderate to severe turbulence when flying over the plant, and therefore, similar mitigation for BEP II would not mitigate the significant adverse impact to aviation safety posed by the BEP II cooling tower and HRSG stack thermal plumes.
10. The following conditions of certification do not address the aviation safety issue but will mitigate any potential impacts on surface/ground traffic and transportation issues.

PROPOSED CONDITIONS OF CERTIFICATION

TRANS-1 The project owner shall comply with Caltrans and any affected jurisdiction's limitation on vehicle sizes and weights. In addition, the project owner or its

contractor shall obtain necessary transportation permits from Caltrans and any affected jurisdiction for roadway use.

Verification: In the Monthly Compliance Reports (MCRs), the project owner shall submit copies of any transportation permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file on site for at least six months after the start of commercial operation.

TRANS-2 The project owner or its contractor shall comply with Caltrans and any affected jurisdiction's requirement for encroachment into public rights-of-way and shall obtain necessary encroachment permits from Caltrans and any affected jurisdiction.

Verification: The project owner shall include in its Monthly Compliance Reports copies of encroachment permits received during the reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file on-site 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 acquired by the project owner and/or subcontractors concerning the transport of hazardous substances.

TRANS-4 The project owner shall prepare a parking plan(s) for the pre-construction, construction and operation phases of the project in consultation with the City of Blythe. The project owner shall provide a copy of the City of Blythe's written comments and a copy of the parking plan(s) to the CPM.

The parking plan shall include a policy to be enforced by the project owner stating all project-related parking occurs on-site or in designated off-site parking areas as shown on the plan. The City shall have 30 calendar days to review the parking plan and provide written comments to the project owner.

Verification: At least 30 calendar days prior to site mobilization, the project owner shall provide a copy of the parking plan to the CPM for review and approval with documentation of review and comments by the City of Blythe.

TRANS-5 The project owner shall prepare a construction traffic control and implementation plan for the project and its associated facilities. The project owner shall consult with the affected local jurisdiction(s), Caltrans (if applicable) and the Blythe School District, in the preparation of the traffic control and implementation plan. The project owner shall provide a copy of the local jurisdiction's, Caltrans, and school district written comments and a copy of the traffic control and implementation plan to the CPM.

The traffic control and implementation plan shall include and describe the following minimum requirements:

- Timing of heavy equipment and building materials deliveries and related hauling routes;
- Redirecting construction traffic with a flag person;
- Signing, lighting, and traffic control device placement;
- Timing of construction work hours and arrival/departure intervals outside of peak traffic periods;
- Coordinating measures for eliminating any traffic safety hazards to school buses and school children on or near the construction worker travel and truck routes;
- Ensuring safe access to the main entrance;
- Ensuring access for emergency vehicles to the project site;
- Developing a emergency notification plan in case of a hazardous materials release including alternative transportation routes if I-10 was closed to traffic;
- Closing of travel lanes on a temporary basis;
- Ensuring access to adjacent residential and commercial property during the construction of all linears; and
- Devising a construction workforce ridesharing plan.

The project owner shall submit the proposed traffic control and implementation plan to the affected local jurisdiction, school district(s) and Caltrans (if appropriate) for review and comment. The project owner shall provide to the CPM a copy of the transmittal letter submitted to the affected local jurisdiction, school district(s) and Caltrans requesting their review of the traffic control and implementation plan. The project owner shall provide any comment letters to the CPM for review and approval.

Verification: At least 30 calendar days prior to site mobilization, the project owner shall provide a copy of the traffic control and implementation plan to the CPM for review and approval with documentation of review and comment by the reviewing agencies. The reviewing agencies shall have 30 calendar days to review the plan.

TRANS-6 The project owner shall submit to the CPM for approval a private vehicular access easement (PVAE) plan securing a secondary vehicle access (at the minimum, to be used by emergency services vehicles). The installation/construction of the PVAE shall be completed to allow emergency services vehicles access to the power plant property at anytime.

The PVAE plan shall include a diagram that shows: the power plant property, the location and dimensions of the proposed PVAE, its connection to the public right-of-way and the proposed vehicle access road (driveway) on the power plant property. Also, the PVAE plan shall include copies of the executed PVAE and the executed PVAE maintenance/repair agreement with the affected property owner.

The project owner shall provide a copy of the PVAE plan to the affected local jurisdiction's public works department and affected fire protection department for review and comment. The project owner shall provide to the CPM a copy of the transmittal letter submitted to the local jurisdiction's public works department and fire protection department requesting their review of the PVAE plan.

Verification: At least 60 calendar days prior to the start of construction, the project owner shall provide to the CPM for review and approval a PVAE plan. Prior to the start of construction, the installation/construction of the PVAE shall be completed to allow emergency services vehicles access to the power plant property. Within 14 days after installation of the PVAE the project owner shall contact the CPM to request an inspection.

TRANS-7 The project owner shall repair affected public rights-of-way (e.g., highway, road, bicycle path, pedestrian path, etc.) to original or near original condition that has been damaged due to construction activities conducted for the project and its associated facilities.

Prior to start of site mobilization, the project owner shall notify the affected local jurisdiction(s) and Caltrans (if applicable) about their schedule for project construction. The purpose of this notification is to request the City of Blythe and Caltrans to consider postponement of public right-of-way repair or improvement activities until after project construction has taken place and to coordinate construction related activities associated with the applicable identified local jurisdiction or Caltrans project(s) with the project owner.

Prior to the start of site mobilization, the project owner shall photograph, or videotape the following public right-of-way segments and intersections: Hobsonway West between Neighbors Boulevard and Buck Boulevard, and Riverside Avenue from Neighbors Boulevard Buck Boulevard. The project owner shall provide the CPM, the affected local jurisdiction(s) and Caltrans (if applicable) with a copy of these images.

Verification: At least 30 calendar days before site mobilization, the project shall provide copies of the photographic images of the road segments noted above to the CPM, the affected local jurisdiction(s) and Caltrans (if applicable). Within 60 calendar days after completion of construction, the project owner shall meet with the CPM, the affected local jurisdiction(s) and Caltrans (if applicable) to identify sections of public right-of-way to be repaired, to establish a schedule to complete the repairs and to receive approval for the action(s). Following completion of any public right-of-way repairs, the project owner shall provide to the CPM a letter signed by the affected local jurisdiction(s) and Caltrans stating their satisfaction with the repairs.

TRANS-8 The project owner shall install lighting fixtures identical to those installed at BEP I pursuant to the City of Blythe's requirements and consistent with FAA requirements (FAA Advisory Circular 70/7460-1J).

Verification: At least thirty days prior to the start of HRSG stack construction, the project owner shall provide the City of Blythe, the Riverside Airport Land Use

Commission, the FAA, and the Energy Commission's CPM a copy of the stack lighting plan.

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ATTACHMENT A

Information Related to Pilots Experience With Turbulence from Blythe Power Plant Cooling Tower Thermal Plumes

Pilot Name	Aircraft Type/ Number of Engines	Date of Flight	Time of Day	Elevation Above Ground Level (feet)	Airspeed MPH	Weather Conditions	Condition Experienced
Rory Watkins	Cessna/single	December 2002	Afternoon	1000	75	Clear and calm winds	Severe turbulence
Pat Wolfe	Cessna/single	March 2003	Morning	350	80	Clear and calm winds	Severe turbulence
Joe Sheble	Cessna/single	Jan/Feb 2004	Morning	300	90	Clear and calm winds	Moderate turbulence
Luis Magana	Beechcraft/two engines	May 4, 2004	Morning	550	110	Clear and calm winds	Moderate to severe turbulence
Eric Nordberg	Lear jet/two engines	May 4, 2004	Morning	550	142	Clear and calm winds	Moderate to Severe turbulence

ATTACHMENT B
Exhaust Plume Turbulence
Testimony of William Walters, P.E.

BEP II EXHAUST PLUME/AIR TURBULENCE CONCLUSIONS

During cold calm wind conditions, the cooling tower plumes can either present as a visual plume that will require air traffic to change flight patterns to avoid the plumes, or can present as clear air turbulence that may create moderate to severe turbulence for small aircraft flying through the plume. The heat recovery steam generator (HRSG) plumes will also create turbulence during calm wind conditions, but the effect will be limited in duration for the much smaller HRSG plume. The most significant turbulence, for both cooling towers and HRSGs, will occur during cold calm periods, and these conditions are not the type of conditions when natural thermal turbulence would occur. Therefore, for uninformed or novice pilots, the power plant caused turbulence impacts could create an unexpected and hazardous threat when flying at low altitudes.

Conditions conducive to creating the most significant plume turbulence; calm wind speed conditions (<2 knots or 1 meter per second [m/s]) when the ambient temperature is below 70F, will occur approximately 550 hours per year (based on three years of Blythe Airport meteorological data). Conditions conducive to creating cooling tower visible plumes that may extend vertically 500 feet or more are estimated to occur approximately 50 to 150 hours per year (based on SACTI and CSVP modeling results). The conditions conducive for turbulence and plume occurrence overlap and both occur almost exclusively from October through May and with the vast majority occurring during the overnight and morning hours (10 pm to 10 am).

A more detailed examination of the factors affecting the plumes and their potential for impacts is provided below.

BEP II vs. BEP I Design Comparison

The BEP II power plant design is very similar to the BEP I design. Staff has analyzed the thermal plume potential for both the existing BEP I power plant and the proposed BEP II power plant. Both power plant designs feature two 7F frame gas turbine/HRSGs and both designs include very similarly sized 8-cell cooling towers. The exhaust volume flow, velocities, and temperatures for the two power plants would be very similar. The as built design data and source test information received from the BEP I facility (Blythe Energy 2004) indicates that the BEP I “as-built” cooling tower initial exhaust velocity may be slightly lower than the BEP II design value and that the BEP I “as-built” Turbine/HRSG exhaust temperature and initial exhaust velocity may be higher than the BEP II design values.

The overall conclusion is that the BEP II power plant design is very similar to the existing BEP I power plant, so the potential thermal plumes would also be very similar, particularly for the cooling towers which have nearly identical design variables.

General Exhaust Plume Velocity Considerations

The plume velocity is affected by a number of factors after release, including; initial plume momentum, thermal buoyancy, wind speed, and adjacent plumes. Each of these factors is discussed below.

Initial Plume Momentum

Exhaust plumes momentum is a function of the velocity and overall mass of the plume. The initial momentum of the plume is the initial force that is given to the plume. For a cooling tower that initial momentum can be very high considering the large mass flow and fairly high velocity. HRSG plumes typically have higher stack velocities than cooling tower plumes but have much lower total mass flow rates.

Thermal Buoyancy

The thermal buoyancy of a plume can help retain or increase the plume vertical velocity depending on the buoyant force and ambient conditions. Thermal buoyancy is greatest for the cooling towers when the temperatures are cold and relative humidities are high as this causes the highest differential between exhaust temperature and ambient temperature.

Wind Speed

Wind causes increased mixing which limits both the initial vertical plume height potential due to its initial momentum and the effect of the thermal buoyancy. It is under calm conditions that plume maintain their coherence and will maintain the highest velocity potential.

Adjacent Plumes

Adjacent plumes can merge and the resultant merged plume will have a greater force than a single uncombined plume, which will increase the potential plume vertical velocity potential and air traffic associated impacts.

General Cooling Tower and HRSG Design Considerations

Cooling Towers

Cooling tower exhausts conditions vary based on the ambient condition. As the ambient temperature lowers or the ambient relative humidity increases there is a lower water carrying capacity in the ambient air. Cooling towers release heat primarily through the evaporation of water and also through the increase in overall air temperature. When it is cold enough with a high enough relative humidity the exhaust will cause a visible plume that can be quite large under the right ambient conditions. For the Blythe area these conditions do not occur frequently. The plume condition of most concern in terms of potential air turbulence impacts would be one with thermal buoyancy that does not have visible plume or may only have a limited visible plume that dissipates well below the normal height of air traffic. However, large visual plume would require avoidance and therefore could alter desired flight patterns.

When it is very hot and dry the ambient air can hold more water than necessary to release the heat provided to the cooling tower, so in these circumstances the cooling tower will actually act like a swamp cooler. The plume heights under these conditions will be limited as the plumes have no thermal buoyancy. Therefore, cooling tower exhaust plumes in hot/dry conditions are not a major concern.

HRSGs

HRSG exhausts are affected by ambient conditions but to a much lower degree than cooling towers. In general, the exhausts at a given load have fairly consistent flow and temperatures over a range of ambient conditions. The differential of the exhaust temperature and the ambient temperature define the amount of thermal buoyancy, so like a cooling tower the worst case thermal buoyancy will occur during cold weather when temperature differential is the highest, but this affect is not as marked as in the cooling tower exhaust. The plumes from HRSGs are generally more widely spaced and would not merge in the same way as the adjacent cooling tower exhaust plumes so the overall size of the plume, if encountered by an aircraft, would be much smaller than a cooling tower plume. The cooling tower exhausts are more numerous and closer together than the HRSG plumes, which will allow their exhausts to merge more effectively than the two HRSG exhausts. Also when flying above the length of the cooling tower (472 feet long) the turbulence would exist for much longer than would be the case for the HRSG based turbulence.

Thermal Source of Power Plant Plumes

The thermal intensity of a plume can cause the vertical velocity to increase or maintain higher velocities for longer periods of time. This can be seen in the estimated higher final plume rise for exhausts that are released at temperatures above ambient conditions. Cooling towers and HRSGs both include thermal components to their exhausts. A simple explanation of each is as follows:

Cooling Tower

Most of the heat reduction in the conventional cooling tower is performed through the evaporation of water. The fraction of total heat imparted to the dry air stream varies from approximately 30% during very cold and wet conditions, to a small negative value at very warm and dry conditions when the cooling tower will act like a swamp cooler. As temperature decreases and relative humidity increases a higher percentage of the total heat reduction will be in the air stream, so the temperature differential of the cooling tower exhaust and the ambient air conditions increases so the highest thermal buoyancy will occur under cold/wet conditions and lessen as the temperature increases and as the relative humidity decreases.

A reasonable worst-case under very cold and wet conditions (30°F and 100% RH), for a power plant the size of BEP II, the cooling tower could impart about 140 MW of heat (out of 330 MW). Whereas at a hotter drier condition (75°F and 25% RH) the cooling tower could impart only 30 MW to the air.

HRSG

The HRSG exhaust temperature will be around 200°F when at load. The thermal difference between the exhaust and ambient conditions, unlike the cooling tower, is always a positive differential values and would range from around 20 MW of heat at 115°F to about 45 MW of heat at 30°F.

Natural vs. Power Plant Vertical Winds

Natural vertical winds can be caused by several phenomena including storms, and ground heating (thermals). For our purposes the natural phenomena of comparison would be the ground heating thermal winds are being compared. Natural thermals might be able to exceed this level near the ground in small patches (very little data was found for thermal at low altitude) and natural thermal caused dust devils are also noted to be a concern to small aircraft. The time of day and time of year for the impact of natural thermals and the power plant exhausts are different. The power plant impacts lessen during hot days, and are greatest on cold moist nights or mornings. Additionally, the heat density of the power plant exhaust is much greater than heat that could be transferred from the ground in the same area of space, which for low level thermal intensity is likely a reasonable comparison. At higher altitudes natural thermals can become much larger as they join together in single larger masses, and should be of a lower concern near ground level due to their relatively small horizontal aspect (Lester 2001).

Additionally, thermals are an expected phenomenon and will give some physical warning before an aircraft gets close to the ground. This natural phenomenon should not be abrupt at the low altitudes of concern, like the abrupt plume phenomena of the power plant plumes, it should be felt for some time prior to landing. Also, from the tops of the thermals the size of the thermals will increase for a period and then decrease close to ground. The velocity of desert thermals ranges from 200 to 400 feet per minute (1 to 2 m/s) to extremes of 1,000 to 2,000 feet per minute (5.1 to 10.2 m/s)during extremely hot dry conditions (Lester 2001).

Regulatory Considerations

While the Federal Aviation Authority (FAA) or Caltrans Aeronautics does not routinely access the impacts from man-made vertical plumes, and do not have standards or regulated methods by which to assess such plumes, at least one other country does have such a standard and regulated methods. The Civil Aviation Safety Authority of Australia (CASA) has established a threshold of 4.3 m/s plume average velocity (846 feet per minute [fpm]) at 360 feet above ground level as a significance criteria. Studies of vertical plume velocities are mandated for any source that has the potential to create this type of plume velocity within 15 kilometers of an airport. CASA also requires the plume studies to be performed using specific modeling methodologies (CASA 2004).

BEP II Cooling Tower Design Specifics/ Cooling Tower Plume Assessment and Modeling

The BEP II cooling tower has the following design characteristics:

Parameter	Parameter Value	Notes
Exhausts	8 Cells	Linear 1 x 8 design
Diameter	approx 33 feet	Each cell
Height (plant agl)	40 ft	plant agl = above plant ground level
Flow	1,430,000 acfm	Each cell
Velocity	8.5 m/s (1,670 fpm)	19 mph
Exhaust Temperature	approx 60 to 95°F	Varies with ambient conditions
Exh. Max. Delta Temp	35-40°F above ambient	Occurs during low ambient temp.

Source: Caithness Blythe II, LLC 2002a,b

Modeling a single cooling tower cell using the SCREEN3 model indicates that the final plume rise for a single cell would be at least 2,400 feet under low temperature and low wind speed unstable or neutral stability conditions. This model limits plume rise to its assumed mixing height so the final plume height potential cannot be assessed with this model. However, this model indicates that the plume will rise well over 500 feet above ground, which would indicate the plume velocity would likely still be quite high at 500 feet above ground.

The effect of the mechanical velocity is that under calm conditions the average plume velocity, even if neutral in buoyancy will be on average one-half of its starting velocity at 6.25 stack diameters up from the release point (Katestone 2003). This means that the cooling tower plume-average velocity without any contribution due to thermal rise or due to the additive effect of the adjacent cell plumes could be about 4.25 m/s (837 fpm) about 250 feet above ground. Adding the eight adjacent stacks could increase that by a factor of 68 percent ($8^{0.25}$), increasing the average combined plume velocity to 7.1 m/s (1,398 fpm). The thermal contribution would likely mean that the plume's vertical velocity is likely to be at or above its original release velocity of 8.5 m/s (1,673 fpm)at 250 feet above ground. Therefore, it is expected that the plume average velocity at 500 feet would be greater than 4.3 m/s (846 fpm) under the proper ambient conditions.

Alternative Cooling Technology – Air Cooled Condensor

The use of an air cooled condensor (ACC) has been evaluated as an alternative cooling technology to reduce water use. This alternative technology evaluation includes an all air-cooled option and an hybrid option that uses an ACC as the primary cooling device and a smaller wet cooling tower to address peak cooling needs. The alternative cooling technology analysis did not provide complete design specifications for the ACC, and the design specifications can vary based on a number of factors such as noise control. For the purposes of this assessment the following design specifications have been assumed:

ACC Option
ACC Cells - 45
ACC Exhaust Release Height – 117 feet

ACC Cross Section – 70,000 square feet
Exhaust Temperature Rise – 25°F

These variables over simplify the operation of the ACC, which was designed for a high ambient temperature. At lower temperature the ACC would likely operate with few cells operating and with a corresponding higher exhaust temperature rise.

From a thermal turbulence perspective the ACC releases all of the power plant's cooling load to the air in the ACC exhaust, while the cooling tower releases most of its cooling load through the evaporation of water. The worst-case cooling tower heat load to air is calculated to be approximately 140 MW (@ 330 MW total load) while the entire heat load to the ACC is released to the air stream in the form of temperature rise.

Using the SCREEN3 model the final plume rise comparison of the ACC using an equivalent diameter and Cooling Tower (single cell and combined cell equivalent diameter) at three separate ambient conditions (D stability, 1 m/s wind speed) are predicted to be as follows:

30F, 80% RH	**Buoyancy Flux**	**Momentum Flux**	**Plume Rise**
ACC	2,613 m^4/s^3	15,815 m^4/s^2	11,900 feet
Cooling Tower Cell	148 m^4/s^3	1,699 m^4/s^2	2,515 feet
Cooling Tower Combined	1,186 m^4/s^3	13,592 m^4/s^2	8,658 feet
70F, 30% RH			
ACC	2,424 m^4/s^3	15,873 m^4/s^2	11,383 feet
Cooling Tower Cell	47 m^4/s^3	1,787 m^4/s^2	1,268 feet
Cooling Tower Combined	377 m^4/s^3	14,293 m^4/s^2	4,373 feet
90F, 10% RH			
ACC	2,340 m^4/s^3	15,899 m^4/s^2	11,146 feet
Cooling Tower Cell	A	1,828 m^4/s^2	857 feet
Cooling Tower Combined	A	14,620 m^4/s^2	2,350 feet

A – SCREEN3 resets a negative buoyancy flux to zero.

The buoyancy flux, momentum flux, and plume rise are indications of the overall power of the exhaust and its ability to create turbulence. The SCREEN3 results show that all three of these factors are greater for the ACC than the cooling tower under the range of conditions modeled, and while the plume rise height for the ACC and cooling tower are similar for the 30°F case the differential in plume height grows as the ambient temperature rises. Therefore, the ACC will have the potential to cause significant turbulence over a much wider range of ambient conditions and number of hours annually than the cooling tower.

The ACC for the hybrid option would be 2/3rd the size of the ACC for the air-cooled only design and may have a modeled plume rise lower than the cooling tower at very low temperatures but would have higher predicted fluxes and plume rise at higher temperatures. The cooling tower design for the hybrid option is a single cell tower that would operating at higher temperatures than the existing cooling tower design; however, the cooling tower would only be used when necessary at higher ambient temperatures

when the smaller ACC could not handle the entire cooling load. The design of the cooling tower was not completed in a manner that allows a critical determination of its associated thermal or visible plume potential.

The ACC's calculated initial plume velocity of 3.0 m/s (590 fpm) is lower than the cooling tower cell exhaust velocity of 8.5 m/s (1,673 fpm) due to the release occurring over the entire cross-section of the ACC; however, the thermal buoyancy should cause some acceleration of this speed. The velocity calculated using the jet velocity technique for calm conditions (i.e. initial velocity at 6.25 stack diameters above release) would equal a velocity, neglecting the thermal contribution, of 1.5 m/s (295 fpm) at 1,860 above ground. Additionally, the overall buoyancy of the ACC is much greater than the cooling tower and the large consolidated ACC exhaust plume would be more resistant to the effects of the wind over more wind directions and at higher wind speeds than the linear cooling tower exhaust plume.

SUMMARY

The BEP II cooling tower will have the potential to cause vertical plumes that could cause moderate to severe turbulence for low flying aircraft when the ambient conditions are right. The potential for plume related turbulence impacts will be strongest when the wind speeds and temperature are low. These ambient conditions do not overlap with the conditions that cause natural thermals. Additionally, when the weather is cool and wet enough the visual plumes created by the cooling tower would require air traffic to adjust landing patterns to fly around the visual plume.

The ACC cooling alternative would also cause air turbulence at low altitudes. The turbulence caused by the ACC would be expected to be worse than that caused by the cooling tower during warmer ambient temperatures and during periods with higher wind speeds.

REFERENCES

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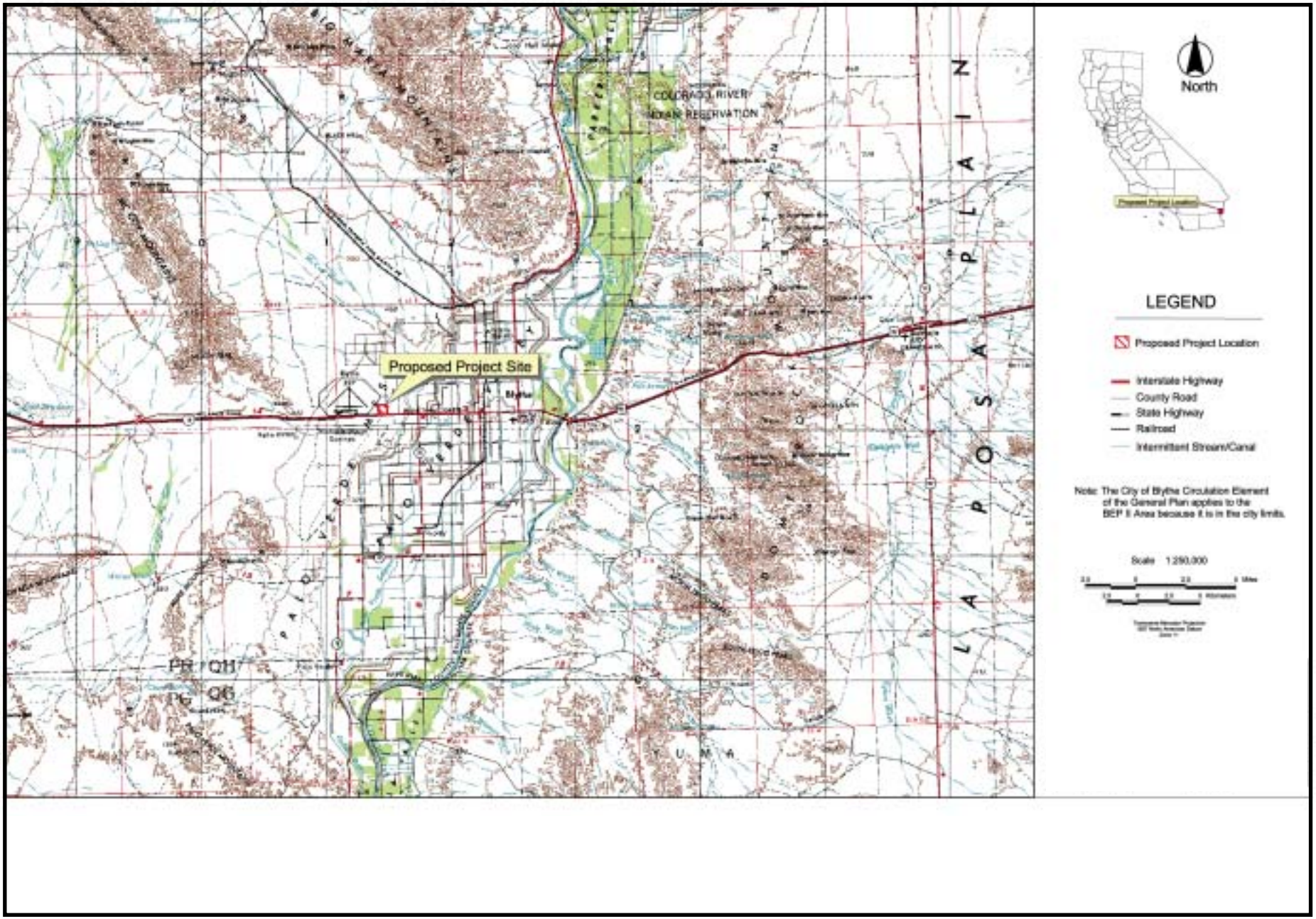
TRAFFIC AND TRANSPORTATION - FIGURE 1

Blythe Energy Project Phase II - Project Site Area

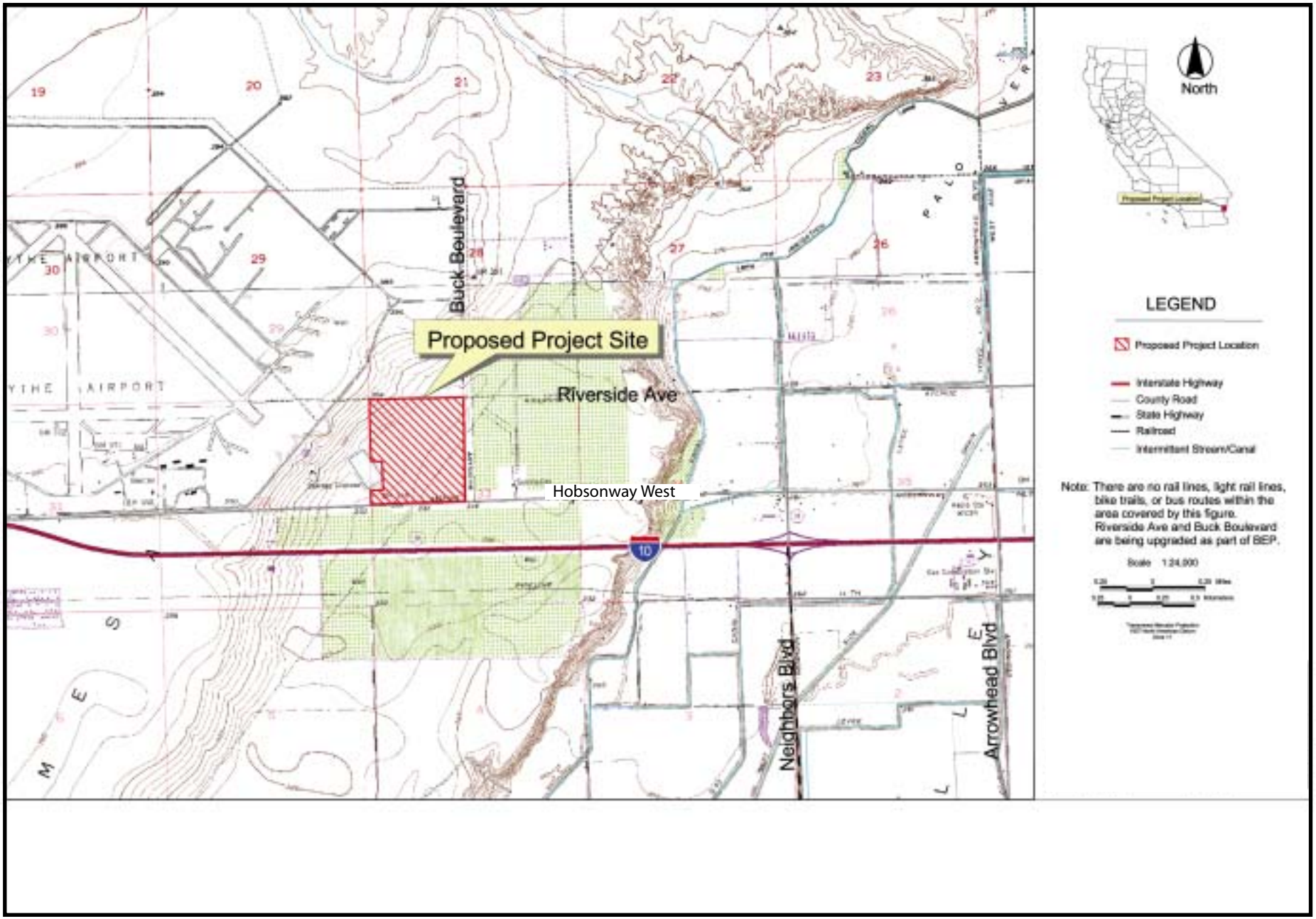


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: BEP II 2002a, Figure 7.4-1

TRAFFIC AND TRANSPORTATION - FIGURE 2

Blythe Energy Project Phase II - Project Site Vicinity



SOURCE: BEP II 2002a, Figure 7.4-2

TRAFFIC AND TRANSPORTATION - PHOTO 1

Blythe Energy Power Plant and Blythe Energy Project - Phase 2 Proposed Site

This photograph was taken from an airplane on final approach to Runway 26 at Blythe Airport, 250 feet above ground level.

Note that Runway 26 is substantially obscured.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: Photo taken by Commission Aviation Consultant Bill Arnold on November 3, 2004

TRANSMISSION LINE SAFETY AND NUISANCE

Testimony of Obed Odoemelam, Ph.D.

INTRODUCTION

As described in the Application for Certification, the proposed Blythe Energy Project Phase II (BEP II) would be electrically connected to the existing Western Area Power Administration (Western) 161/230 kV Buck Boulevard Substation located at the northeastern corner of the Blythe Energy Project Phase I (BEP I) previously permitted by the California Energy Commission. BEP I is presently connected to this same Buck Boulevard Substation through three short tie-in lines. A new 118-mile, single-circuit 500 kV Desert Southwest Transmission Project (DSWTP) interconnection to the Devers Substation is proposed to deliver the BEP II-generated power to the region's load centers via the California Independent System Operator (CAL ISO) power grid. This new 118-mile transmission line (which is proposed by the Imperial Irrigation District, (IID), and the Desert Southwest Power, DSP) would not be part of BEP II and is noted because of its evaluation from a cumulative impacts perspective. The field and non-field impacts of most concern in this Transmission Line Safety and Nuisance analysis are those from transmitting the BEP II generated energy to the Buck Boulevard Substation, which is connected to the Western Blythe Substation. The proposed BEP II connection to the Buck Boulevard Substation is an overhead, 2,500-ft, 500 kV line stretching from BEP II's generators to the connection points within the Substation. It would be located entirely within the BEP I/BEP II site boundaries, meaning that no off-site power lines would be construction with specific regard to the proposed BEP II.

The electrical safety and reliability of the Buck Boulevard Substation for the proposed and any alternative BEP II-related interconnection scheme would normally be ensured through specific Conditions of Certification in the Transmission System Engineering (TSE) section of staff's testimony. However, TSE staff is currently unable to specify such Conditions of Certification because of the inadequacy of the information on the potential impacts of pending area transmission projects that could be utilized to transmit the generated power to area load centers (See **Transmission System Engineering section**).

The purpose of this staff analysis is to assess whether the proposed transmission plan would be adequate to ensure that the generated energy is transmitted without the health and safety impacts possible from the current flow to be involved. If these line impacts were to be as staff expects for the total amount of power to be transmitted, staff would regard the proposed line designs and operational plan as reflecting compliance with the applicable health and safety laws, ordinances, regulations and standards (LORS). If these impacts were to be significantly higher than appropriate, staff could recommend mitigation before the BEP II energy is introduced into the area's power grid. Staff's analysis focuses on the following issues:

- 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

Discussed below by subject area are design-related LORS applicable to the physical impacts of the existing and new overhead transmission lines to be used. There presently are no local laws or regulations specifically aimed at those aspects of electric line structure or dimensions that influence the magnitude of the impacts noted above. The only such regulations are local requirements for such lines to be located underground in new housing developments because of the potential for visual impacts on the landscape. Such requirements are not aimed against any specific health effects.

AVIATION SAFETY

Any hazard to area aircraft would relate to the potential for collision in the navigable air space. The applicable federal LORS discussed below are intended to ensure the distance and visibility necessary to prevent such collisions.

Federal

- Title 14, Code of Federal Regulations (CFR), Part 77, “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 a 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 all structures are 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 produced by the physical interactions of line electric fields. Since electric fields are unable to penetrate most materials, including the ground, 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 perception can be assessed from field strength

estimates obtained for the line design. The 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 the perceivable interference with radio or television signal reception or interference with other forms of radio-frequency 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 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. For such lines, interference is minimized through the use of specific low-corona cables as conductors. The FCC requires each line operator to mitigate all complaints about interference on a case-specific basis.

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.

Several design and maintenance options are available for minimizing these induced fields. 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 or state regulations that 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. These practices are effective and do not significantly impact line safety, efficiency, maintainability, and reliability. All modern overhead high-voltage lines are designed to assure compliance with such noise limits. As with radio-frequency noise, such 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 and thus, potentially possible from the proposed 500 kV line. Research by the Electric Power Research Institute (EPRI 1982) has validated this for the under-345 kV lines by showing the fair-weather audible noise from modern transmission lines to be generally indistinguishable from background noise at the edge of a 100-foot right-of-way. Modern 500 kV lines are designed and constructed in ways that minimize such noise. Underground lines do not generate such noise, since they cannot produce the responsible surface-level electric fields.

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" specify tree-trimming criteria to minimize the potential for power line-related fires.
- Title 14, California Code of Regulations, Section 1250. "Fire Prevention Standards for Electric Utilities" specify utility-related measures for fire prevention.

HAZARDOUS SHOCKS

The hazardous shocks addressed through the following regulations and standards are those 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" 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 (CCR), Sections 2700 et seq.: "High Voltage Electric Safety Orders" establish essential requirements and minimum standards for safely installing, operating, working around, and maintaining electrical installations and equipment

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.

NUISANCE SHOCKS

Industry Standards

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. There are no design-specific federal or state regulations to limit nuisance shocks in the transmission line environment. For modern overhead high-voltage lines, such shocks are effectively minimized through grounding procedures specified in the National Electrical Safety Code (NESC) and the joint guidelines of the American National Standards Institute (ANSI) and the Institute of Electrical and Electronics Engineers (IEEE). As with the proposed overhead lines, the applicant is responsible in all cases for ensuring compliance with these grounding-related practices within the right-of-way.

ELECTRIC AND MAGNETIC FIELD EXPOSURE

The possibility of deleterious health effects from EMF 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 the CPUC, other regulatory agencies, and staff, has not established that such fields pose a significant health hazard. 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 feasible reduction of such fields without affecting safety, efficiency, reliability, and maintainability.

While there is considerable uncertainty about EMF health effects, the following facts have been established from the available information and have been used to establish existing policies:

- Any exposure-related health risk to the exposed individual will likely be small.
- The most biologically significant patterns (e.g., high-level, short-term versus low-level, long-term) 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 below levels existing before the present health concern arose. The CPUC has further determined that such reduction should be

made only in connection with new or modified lines. It requires each electric 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. The other utilities, which are not within the jurisdiction of the CPUC, voluntarily comply with these CPUC requirements by designing their lines in keeping with the guidelines of the major area utility. The service utility in this case is Western. This field reduction policy of the CPUC resulted from assessments made to implement CPUC Decision 93-11-013.

In keeping with this CPUC policy, staff requires each applicant to show how each proposed overhead line would be designed to comply with the EMF-reducing design guidelines applicable to the utility service area involved. For existing lines, staff assesses compliance by comparing the fields with fields from compliant lines of the same voltage and current-carrying capacity. The available reducing measures can impact line operation if applied without appropriate regard for environmental and other local factors bearing on safety, reliability, efficiency, and maintainability. Therefore, it is up to each applicant to ensure that such measures are applied to an extent that does not significantly affect line operation and safety. It is the extent of such applications that is reflected by the ground-level field strengths as measured during operation. These field strengths can be estimated for any given design using established procedures and can be verified from actual measurements during operations. 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 or modified 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. It is for this reason that the permitted BEP I lines were designed to incorporate Western's field strength-reducing guidelines, as would the new on-site 500 kV lines that would connect BEP II's generators to the Buck Boulevard Substation. Compliance with these Western guidelines would constitute compliance with the CPUC requirements for line field management. Staff recommends a specific condition of certification (**TLSN-1**) to ensure implementation of the design measures necessary. .

Industrial Standards

There are no health-based federal regulations or industry codes specifying 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 (such as Florida, Minnesota, New Jersey, New York, and 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 and 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 such as hair dryers, electric shavers, and electric tooth brushes (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

The proposed BEP II would be located on a 76-acre parcel within the expanded site of BEP I, approximately five miles west of the center of the city of Blythe, in Riverside County, California. The project's generators would be located approximately 600 feet south and 800 feet west of those of BEP I. The new interconnection from the generators to the Buck Boulevard Substation would be the noted 2,500 feet long, 500 kV line, located entirely within the BEP site boundaries (Blythe Energy, 2002, pp. 7.2-3, 7.6-1). The Buck Boulevard Substation would be connected to the Blythe Substation by a 1,500-ft 161 kV interconnection line with a capacity for 230 kV operation.

Since there are no residences around the proposed project site and related tie-in lines, the long-term residential field exposures at the root of the present health concern would be insignificant for this BEP II project. The only related EMF exposures of potential significance to staff are the exposures to BEP II workers, regulatory inspectors, maintenance personnel, approved guests. These types of exposures are short-term and well understood as not significantly related to the present EMF-related health concerns.

PROJECT DESCRIPTION

The proposed BEP II and related facilities would consist of the following major segments:

- a new 500 kV line extending 2,500 feet from BEP II's on-site integration switchyard to connect the project's generators with Western's Buck Boulevard 116/500 kV Substation;

- an on-site integration switchyard; and
- project-related modifications within the Buck Boulevard Substation.

As is typical for single-circuit 500 kV lines, the new on-site connection lines would be supported on steel lattice structures designed to provide a minimum conductor height of 65 feet, in keeping with GO-95 requirements. Construction and operation would be according to Western's standards and practices reflecting compliance with existing LORS. The Blythe Substation to be connected to the Buck Boulevard Substation presently interconnects with five 161 kV regional lines, three of which are owned by Western, one by the Imperial Irrigation District (IID), and the other by Southern California Edison (SCE). The field impacts from the added BEP II power would be encountered along the routes of these lines if they were utilized for regional power transport or along the route of the proposed DSWTP if actually built and so utilized.

IMPACTS

GENERAL IMPACTS

GO-95 and Title 8, 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 hazard previously discussed in connection with hazardous shocks or aviation hazards. The noted field impacts that manifest themselves as nuisance shocks, radio noise, communications interference, and magnetic field exposure are of secondary concern. The relative magnitude of such impacts would be reflected in the field strengths characteristic of a given line design. Given the present CPUC requirement to maintain the noted impacts within the levels associated with existing lines, compliance with applicable LORS would be achieved by showing the project-specific fields (from the new on-site lines or existing BEP lines to be utilized) to be within the range associated with Western's lines of the same voltage and current-carrying capacity.

PROJECT SPECIFIC IMPACTS

Aviation Safety

As noted by the applicant, (Blythe Energy 2002, page 7.17-8), the Blythe Airport is located approximately one mile from the project site, pointing to the potential of a collision hazard to utilizing aircraft. As with area Western lines, the proposed BEP II line would be designed and sited sited in compliance with FAA regulations regarding aviation safety. Furthermore, the proposed BEP II site is 60 feet to 70 feet lower in elevation than the Blythe Airport. When this is considered together with the fact that the proposed line would be less than the 200-foot FAA height threshold for a potentially significant collision hazard, they could be seen as unlikely to constitute a new collision hazard to area aircraft. As is common industry practice, however, the applicant will inform the FAA about the proposed line, although no FAA notification would be required. The GO-95 clearance requirements would produce the 37-ft minimum height adequate for safe crop dusting related operations.

Audible Noise and 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. All existing Western lines were built and are currently maintained according to standard Western practices that minimize such surface irregularities and discontinuities. The low-corona design to be used for the new on-site line would be the same as used for other Western lines of the same voltage (Blythe Energy 2002, page 7.17-5) in compliance with the previously noted FCC (47 CFR §15.25) and GO-52 prohibitions against interference with radio communication. Since (a) the edge of the right-of-way would mark the beginning of the areas of possible human habitation around a high-voltage line, and (b) there are no residences around any of the project-related lines, staff does not expect BEP II operations to generate any complaints about operational noise, or interference with the use of residential radio, television, or other electrical equipment. In the unlikely event of specific complaints, Western would be responsible (as with other Western lines) for the necessary mitigation as required by the FCC. Staff recommends a specific condition of certification (**TLSN-2**) in this regard. For an assessment of noise from all aspects of the project construction and operation, please see staff's analysis in the **Noise and Vibration** section.

Fire Hazards

Standard fire prevention and suppression measures for all of Western's lines would be implemented for the proposed BEP II on-site 500 kV line and would be maintained as is standard Western practice. The applicant's intention to ensure compliance with the clearance-related aspects of GO-95 would be an important part of this compliance approach (Blythe Energy 2002, page 7.17-9). Western's fire prevention practices for high-voltage lines would be implemented in compliance with Title 14, California Code of Regulations, section 1250. Staff recommends Condition of Certification **TLSN-4** to ensure implementation.

Hazardous Shocks

Since the proposed on-site 500 kV line would be designed according to GO-95 requirements together with the requirements in specific sections of Title 8, California Code of Regulations, section 2700 et seq. against direct contact with the energized line, staff does not expect it's use to pose a significant shock hazard.

Nuisance Shocks

The potential for nuisance shocks around the new on-site project line would be minimized through standard grounding practices, as are the permitted BEP I and similar Western lines. Staff recommends Condition of Certification **TLSN-5** to ensure that such practices are extended to the proposed on-site line.

Electric and Magnetic Field Exposure

The applicant assessed the potential contribution of the proposed BEP II to the maximally impacted grid lines located along the Buck Boulevard to Blythe Station corridor by comparing the fields from BEP I power flow alone, to fields from the combined flow of power from BEP I and BEP II (Blythe Energy 2002, pp. 7.17-3 through

7.17-5, 7.17-6 through 7.17-8). Staff is in agreement with the applicant's assumptions with respect to parameters bearing on field strength dispersion and exposure levels. Calculations were specifically made for the edges of the line rights-of-way, near the Buck Boulevard and Blythe Substations, and at the points of maximum intensities within the rights-of-way of the major area transmission lines. According to the applicant's calculations, the maximum strength of the background BEPI-related electric fields within this corridor of maximum impacts is 1.8 kV/m, diminishing to 0.5 kV/m at the edge of the right-of-way. The maximum around the substations was calculated as 1.4 kV/m.

The magnetic field strengths to be encountered within the BEP lines' rights-of-way before introduction of BEP II-related power was calculated as 68.9 mG at the point of maximum impact within the rights-of-way and as 9.7 mG at the edges of such rights-of-way. The maximum value around the Buck Boulevard and Blythe Substations was calculated as 78.2 mG.

The BEP I-related Buck Boulevard Substation to Blythe Substation line (to be utilized) would be operated at the existing 161 kV; therefore, the resulting corridor electric fields should remain the same during with the inclusion of BEP II operations. This relative lack of change is reflected by the applicant's calculated values of 1.8 kV/m within the right-of-way and 0.5 kV/m at the edge of the right-of-way. The maximum field intensity around the substations was calculated as 1.4 kV/m. These electric field values are within the values staff would expect for Western lines of the same design and are within the limits of between 1.0 kV/m and 2.0 kV/m specified for the edges of rights-of-way in states with regulatory limits.

Since the magnetic field is the only line field that directly depends on current level, the increased power from BEP II would increase the corridor magnetic field strengths in proportion to the related increase in transmitted power. The applicant calculated the maximum magnetic field strength within the rights-of-way during BEP II power flow as 60.4 mG, diminishing to 8.5 mG at the edge of these rights-of-way. This compares with the higher maximum pre BEP-II value of 68.9, diminishing to 9.7 mG at the edge of the right-of-way. The maximum intensity around the two substations was calculated as 74.4 mG. Staff considers the identified BEP II-related field strength decreases (from the noted Pre-project level of 78.2 mG, in this case of the Substations as an example) as reflecting the impacts of the power to be diverted to the noted 118-mile 500 kV line proposed to transmit the generated power to the region's lead centers. If an alternative line were to be used for such power transmission, staff would require specific information on how such line use would change the calculated field strengths.

The calculated corridor magnetic fields are within the range staff would expect for Western lines of the same current-carrying capacity and much lower than the 150 mG to 250 mG specified for the edges of the rights-of-way by the few states with specific regulatory limits.

These calculated field strengths reflect the effectiveness of Western's standard field reduction measures as applied with respect to the following:

- distance between the conductors and the ground;
- spacing between conductors on the same line;

- distance between conductors in nearby lines;
- line current levels; and
- current flow alignment for effective field cancellation.

These field reduction measures would be applied to the proposed on-site 500 kV connecting lines, in keeping with Western's practices ensuring compliance with current CPUC policy on field strength management. Staff recommends Condition of Certification **TLSN-3** to allow for validation of the reduction efficiency attributable to the design in question.

CUMULATIVE IMPACTS

The previously noted magnetic fields were calculated to reflect the interactive effects of the fields from all the grid lines in the corridor of maximum BEP II impacts and should therefore be seen as representing the maximum post-BEP II exposures of a cumulative nature. As reflected in the calculated values, the lines' potential contribution to any area exposures would be similar to those associated with area Western lines of the same voltage and current-carrying capacity. It is this similarity in field intensity (which reflects the effective implementation of the applicable field strength-minimizing measures) that constitutes compliance with existing CPUC requirements on line field management. The field strength measurement requirements in Condition of Certification **TLSN-3** would allow for assessment of the field strength reduction efficiency assumed by the applicant. The power diversion through the proposed 118-mile line to the Devers Substation would decrease cumulative magnetic field exposure by the amounts reflected in the pre- and post-BEP II field strengths. In the case of an alternative diversion scheme, staff would require specific information on any related impacts on cumulative exposures.

If the Desert Southwest Transmission Project, Blythe Energy Project Transmission Lines, and the proposed Devers to Palo Verde II lines were actually built to facilitate the noted regional power transmission, they would be mostly located within a right-of-way adjacent to the right-of-way for SCE's existing Devers to Palo Verde I line. The combined impacts of these area lines could manifest themselves as the field and non-field impacts assessed in this analysis. Given that (a) the required line designs would be adequate to minimize such impacts and that (b) these rights-of-way would traverse an area with no nearby residents or airports, staff does not expect any such cumulative impacts to be environmentally significant.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population as greater than 50 percent in some areas within a six-mile radius of the proposed BEP II site (please refer to **Socioeconomics Figure 1** in this staff assessment). Census 2000 information suggests the population of the low-income individuals in the area as presently less than 50 percent, meaning that there would be no issue of environmental justice (on the basis of income) for the field impacts of concern in this analysis. The above noted minority profile caused staff to conduct a screening level analysis for potential environmental justice issues on the basis of minority status. Since, (a) there

are no residences around the project site and the transmission lines to be utilized, and (b) the existing and proposed field reduction designs are standard Western designs that are applied throughout the Western service area without regard to minority status, staff regards the field exposure aspect of the environmental justice issue as insignificant for the proposed lines.

COMPLIANCE WITH LORS

The magnitude of the line impacts of concern in this analysis are within the limits contributed by similar transmission lines designed and operated in compliance with Western's field strength reduction guidelines that reflect compliance with present CPUC requirements. Staff, therefore, considers the proposed on-site project transmission line design and operational plan to be in compliance with the health, safety, and design LORS of concern in this analysis. The fields from the BEP I-related lines to be utilized reflect appropriate incorporation of Western field reduction measures in compliance with CPUC policy.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

No public agency or public comments have been received in connection with the project-related impacts discussed in this analysis.

CONCLUSIONS AND RECOMMENDATIONS

Since electric or magnetic field health effects have neither been established nor ruled out for overhead or underground lines, the public health significance of any BEP I or BEP II-related field exposures cannot be characterized with certainty. The long-term, mostly residential magnetic exposure at the root of the present health concern would be insignificant during operations. On-site worker or public exposures would be short-term and at levels associated with Western lines of the proposed voltage 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 would be minimized through grounding and other field-reducing measures applied to all Western lines. As with the existing BEP I-related lines to be utilized, the support structures for the proposed BEP II line are not tall enough above ground to pose a significant collision hazard to utilizing aircraft. The use of corona-minimizing design and construction practices for both the BEP lines to be utilized and the proposed connecting on-site 500 kV line would minimize the potential for corona noise and its related interference with radio-frequency communication around the site.

As with the noted lines to be utilized between Western's Buck Boulevard and Blythe Substations, the proposed 500 kV on-site project lines would be designed and operated to minimize the safety and nuisance impacts of specific concern to staff (while also located away from area residences). Staff does not recommend any changes to the proposed power transmission plan but would recommend clarifying information if an alternative transmission scheme were to be utilized. If the proposed power plant is

approved, staff recommends adoption of the conditions of certification specified below to ensure (a) implementation of the reduction measures proposed for the new on-site lines and (b) validation of the exposure levels assumed from use of the permitted BEP lines.

CONDITIONS OF CERTIFICATION

TLSN-1 The project owner shall ensure that the proposed on-site 500 kV project line is designed and constructed as specified for lines of this voltage class in CPUC's GO-95, GO-52, the applicable sections of Title 8, California Code of Regulations section 2700 et seq., and Western's EMF reduction guidelines arising from CPUC Decision 93-11-013.

Verification: Thirty days before starting construction of the BEP II transmission line or related structures and facilities, the project owner shall submit to the Compliance Project Manager (CPM) a letter signed by a California registered electrical engineer affirming compliance with this requirement.

TLSN-2 The project owner shall ensure that every reasonable effort will be made to identify and correct, on a case-specific basis, any complaints of interference with radio or television signals from operation of the project-related lines and associated switchyards.

The project owner shall maintain written records, for a period of five years, of all complaints of radio or television interference attributable to operation of the plant and the corrective action taken in response to each complaint. Complaints not leading to a specific action or for which there was no resolution should be noted and explained. The record shall be signed by the project owner and also the complainant, if possible, to indicate concurrence with the corrective action or agreement, with the justification for a lack of action.

Verification: All reports of line-related complaints shall be summarized for the project-related lines and included for the first five years' of plant operation in the Annual Compliance Report.

TLSN-3 The project owner shall engage a qualified consultant to measure the strengths of the electric and magnetic fields from the proposed on-site 500 kV line and the BEP I-related lines to be utilized. Measurements shall be made at the Western Buck Boulevard Substation, Western Blythe Substation, and the maximum impact points within and along and at the edges of the right-of-way (for which the applicant presented field strength estimates). All measurements should be made according to Institute of Electrical and Electronics Engineers (IEEE) measurement protocols.

Verification: The project owner shall file copies of the pre-and post-energization measurements with the CPM within 30 days after completion of the measurements. While pre-energization measurements can be made anytime before energization; post-energization measurements shall be initiated within 60 days of beginning operations.

TLSN-4 The project owner shall ensure that the route of the project's on-site 500 kV line is kept free of combustible material according to existing Western practices reflecting compliance with the provisions of Section 4292 of the Public Resources Code and Section 1250, Title 14, of the California Code of Regulations.

Verification: At least 30 days before the line is energized, the project owner shall transmit to the CPM a letter confirming compliance with this condition.

TLSN-5 The project owner shall ensure that all permanent metallic objects within the right-of-way of the proposed 500 kV on-site lines are grounded according to industry standards.

Verification: At least 30 days before the line is energized, the project owner shall transmit to the CPM a letter confirming the intention to comply with this condition. A confirmatory letter of compliance shall be transmitted to the CPM within 30 days of completing the grounding operations.

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VISUAL RESOURCES

Testimony Mark Hamblin

SUMMARY OF CONCLUSIONS

Energy Commission staff analyzed both the potential visual impacts of the proposed Blythe Energy II Project (BEP II) in accordance with the California Environmental Quality Act (CEQA), and the project's compliance with applicable laws, ordinances, regulations, and standards (LORS) pertaining to visual resources. Staff concludes that the proposed project would cause less than significant visual impacts with the effective implementation of the applicant proposed mitigation measures and staff's recommended conditions of certification; and ensure that the project complies with applicable LORS regarding visual resources.

INTRODUCTION

Visual resources are the natural and man-made features of the environment that can be viewed. This analysis focuses on whether construction and operation of the BEP II would cause visual impact(s) under CEQA and whether the project would be in compliance with applicable LORS.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Staff has identified a listing of applicable laws, ordinances, regulations, and standards (LORS) that staff has evaluated to determine the proposed project's compliance. The project's consistency with the LORS is discussed later in this analysis under Compliance With Laws, Ordinances, Regulations, And Standards.

The proposed BEP II site is in the City of Blythe and the boundaries of the City of Blythe's General Plan Study Area. Lands to the north, west and south of the site are within unincorporated Riverside County. The proposed project would be subject to the LORS of the City of Blythe and the County of Riverside.

CITY OF BLYTHE

General Plan Designation - The property site has been designated by the City as Heavy Industrial (I-H). This land use designation includes industrial uses which are relatively intense.

Scenic Highway Map (City Exhibit III-6) shows Hobsonway West, US Interstate 10, Riverside Ave, 14th Ave, Arrowhead Boulevard, and Neighbors Boulevard as proposed "Scenic Highways."

Zoning District/Designation – The project is within a General Industrial (I-G) district. Electric generating plants and terminals are an allowed use within this district.

Community Benefits Agreement - On July 13, 2004, the Blythe City Council approved a Community Benefits Agreement (Agreement) with Caithness Blythe II, LLC. The

Agreement includes by attachment PRC 2002-10 Letter of Conditions for Blythe Energy II (Letter of Conditions). The Letter of Conditions includes, among other items, project conditions pertaining to aesthetic, lighting and signage (visual items) prepared by the City of Blythe Planning Department. The Community Benefits Agreement is executed between the City and Caithness Blythe II, LLC, and does not include the California Energy Commission as a party to it. It should be noted that the terms and conditions of the Agreement were reviewed by staff while developing the recommended conditions of certification for this FSA.

COUNTY OF RIVERSIDE

Palo Verde Valley Area Plan

The Palo Verde Valley Area Plan (PVVAP) guides the evolving character of this expansive agricultural and desert area.

Scenic Highways - There are two highways shown on the PVVAP Figure 8 that have been nominated for County Scenic Highway status due to their scenic value. They currently have status as Eligible County Scenic Highways. The two highways are US Highway 95 as it extends north from US Interstate 10 (I-10) to the San Bernardino County line and Interstate 10 from the western boundary of the planning area to the Colorado River.

Riverside County applies design standards to adjacent properties on these highways. These two highways have not been designated as eligible or official Scenic Highways in accordance with the California Scenic Highways Program. The PVVAP scenic highway policies apply to these routes and their corresponding corridors to help preserve their scenic qualities.

Palo Verde Valley Area Plan - Blythe Airport Influence Policy Area

The Blythe Airport is located west of the City of Blythe adjacent to I-10. The project site is within the boundary of the Blythe Airport Influence Policy Area of this Plan. The Blythe Airport is owned by the County of Riverside and leased to the City of Blythe to operate. The airport is not within the Blythe city limits. The Federal Aviation Administration (FAA) and Riverside County impose restrictions on the uses, concentrations of population, and height of proposed development within this airport influenced area. The boundary of the Blythe Airport Influence Area is shown in PVVAP Figure 4, Policy Areas of the Plan.

PROJECT DESCRIPTION

The following section describes the aspects of the proposed project that may have the potential to cause adverse impacts to visual resources. Please refer to the **PROJECT DESCRIPTION** section of the Final Staff Assessment (FSA) for a more complete discussion of project details.

VISUAL RESOURCES Table 1 presents the dimensions for a number of the project's key components. The heights of the most visible features of the proposed power generation facilities include two 130-foot tall stacks for the heat recovery steam

generator (HRSG), the 93-foot tall HRSG casings, the 98-foot tall brine concentrator, and a 60-foot tall generation building.

VISUAL RESOURCES Table 1
Dimensions of Key Project Components

Component	Height (feet)	Length (feet)	Width (feet)	Diameter (feet)
HRSG Units				
HRSG Casings	93	140	30	
HRSG Stacks	130			18
Generation Building				
Generation Building	60	75	330	
Cooling Tower				
Cooling Tower	40	472	52	
Tanks				
Raw Water Supply Tank	47			52
Demineralized Water Storage Tank	47			52
Other Facilities and Buildings				
Brine Concentrator	98			17
Control Room Building	15	115	40	
Power Control Center	16	25	20	
Workshop/Storage	31	50	120	
Fire Pump House	19	42	27	
Ammonia Storage Area	13	45	30	
Feedwater Pumphouse	26	67	37	
CEM Enclosure	8	24	7	
Inlet Chilling Enclosure (each of two enclosures)	45	48	38	

Source: BEP II 2002a, Table 7.5-1, revised April 2004

SETTING

REGIONAL LANDSCAPE

BEP II would be located on Palo Verde Mesa in eastern Riverside County. The project region encompasses broad, flat desert valleys and north-south trending, highly eroded mountain ranges that rise sharply from the adjacent basins. The region marks the transition zone between the high elevation Mojave Desert and the arid, lower elevation Colorado Desert. Typical landforms include mesas, valleys, mountains, and foothills. The elevation ranges from approximately 250 to 800 feet (BEP II 2002a, p. 7.5-2).

Most development within the region occurs within Palo Verde Valley along the west side of the Colorado River and includes the City of Blythe, and the communities of Mesa Verde, Palo Verde and Ripley, as well as agricultural fields, railroad lines, power transmission lines, and the Palo Verde Dam and diversion works. Most of the agricultural activity in the region also occurs in the valley, and is dominated by irrigated farming consisting primarily of row crops and alfalfa (BEP II 2002a, p. 7.5-2).

Overlooking Palo Verde Valley to the west lays the two-tiered Palo Verde Mesa. The mesa is a broad alluvial plain situated between, and derived from, the McCoy Mountains

to the west, Little Maria Mountains to the north, and Big Maria Mountains to the northeast. To the south are the Mule and Little Chuckwalla Mountains. The mountain ranges add visual variety to the otherwise flat desert landscape.

PROJECT VIEWSHED

The distance zones used within this analysis are defined as *foreground* (0 to .5 mile), *middleground* (0.5 to two miles), and *background* (beyond two miles). These zones of influence contain a number of viewing opportunities. Because the site is situated on an elevated mesa, from lower elevations to the east including the City of Blythe, ground level components would generally be only visible from foreground viewing opportunities in close proximity of the site, typically on Hobsonway and I-10. However, the taller portions of the plant facilities would be visible at distances greater than 10 miles because of the relatively flat terrain and minimal view obstructions. The majority of viewers of the site would be motorists on I-10, located approximately 0.25-mile south of the project site; commercial areas on the east side of Blythe Airport; and rural residences to the west. The Blythe Municipal Golf Course and adjacent residences in the Mesa Bluffs area are located to the northeast. Other locations from which viewers would be able to see the project include the City of Blythe (located approximately five miles to the east), residential subdivisions on the mesa and in the valley, and recreational use areas in the surrounding mountains.

The Blythe Airport is considered potentially eligible for listing in the National Register of Historic Places and could be considered a sensitive viewing location. However, the plant site is located approximately 1.3 miles distant to the east and at an elevation approximately 58 to 60 feet lower than the airport. Thus, views of the plant site from the airport would be limited. Visibility would be attenuated with increasing distance, particularly at times of the year when dust and poor visibility conditions persist.

PROJECT SITE AND IMMEDIATE VICINITY

BEP II would be located on the eastern lower tier of Palo Verde Mesa, which is characterized by a mostly undeveloped desert landscape of level terrain and sparse desert scrub vegetation interspersed with a small amount of irrigated agriculture and containing some industrial, utility, and transportation facilities. The most prominent built feature on the mesa is the recently constructed Florida Power and Light Blythe Energy Project (BEP I) with its prominent geometric forms and industrial character. Views of the mesa are panoramic in scope and encompass a landscape of generally uniform tan coloration interspersed with contrasting dark and light zones. Middleground views reveal a natural setting of stippled appearance due to the contrasts between vegetation, soil, and rock. Closer foreground views present a mosaic of sparse shrub vegetation and desert pavement openings.

The project site and the surrounding landscape are characterized by views that are expansive, though views to the north are partially obstructed by the existing BEP I. Beyond the existing power plant and electric transmission infrastructure; structures are few and widely dispersed. Although the site is undeveloped, portions have been disturbed as a result of construction of BEP I. Several electric transmission lines cross the site supported on wood pole H-frame structures. To the east of the site is the Blythe Substation. Existing sewage oxidation ponds are located to the west of the site, but are

not generally visible from either Hobsonway or I-10. There are three rural residences located within one mile of the plant site and 32 residences located between one mile and two miles of the site. There are 112 residences between two to four miles from the site, and an additional 77 residences located between four and five miles from the site (BEP II 2002a, p. 7.5-11). Of these residences, there are 31 residences that would have views of the plant (BEP II 2002a, p. 7.5-19).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Refer to **VISUAL RESOURCES Appendix VR-1: Blythe Energy Project II Visual Resources Staff Assessment - Summary Analysis Appendix**, **VISUAL RESOURCES Appendix VR-2: Staff Visual Resources Evaluation Methodology**, and the **Compliance With Laws, Ordinances, Requirements, and Standards** section of this analysis for a synopsis of staff's Visual Resources evaluation process.

Key Observation Points And Viewing Areas

The proposed project would be visible from several areas near the project site. Energy Commission staff evaluated the visual impact of the project from each of these areas. Staff uses Key Observation Points[1], or KOPs, as representative locations from which to conduct detailed analyses of the proposed project and to obtain existing condition 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.

Staff evaluated the visual setting and proposed project in detail from several viewing areas represented by the following seven KOPs:

- KOP 1 – Eastbound I-10, approximately 0.3-mile southwest of the project site;
- KOP 2 – Eastbound Hobsonway, approximately 0.4-mile west of the project site;
- KOP 3 – Mesa Verde (Nicholls Warm Springs), approximately 2.5 miles southwest of the project site off Mesa Drive and just south of I-10;
- KOP 4 – Central Blythe, approximately 4 miles east of the project site at Hobsonway and the "C" Canal Levee;
- KOP 5 – Blythe Municipal Golf Course, approximately 4.5 miles northeast of the project site;
- KOP 6 – Westbound Hobsonway at Buck Boulevard, at the southeast corner of the project site; and
- KOP 7 – Westbound I-10, southeast of the BEP II site.

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**

[1] The use of KOPs or similar view locations is common in visual resource analysis. The United States Department of Interior Bureau of Land Management (USDI BLM 1986a, 1986b, 1984) and the U.S. Forest Service (USDA Forest Service 1995) use such an approach.

VR-1. Existing condition photographs are presented in **VISUAL RESOURCES Appendix VR-4**. A discussion of the visual setting for each KOP is presented in the following paragraphs.

KOP 1 – Eastbound I-10

KOP 1 was selected to characterize the visual impact to eastbound motorists on I-10. KOP 1 is located on eastbound I-10, approximately 0.3-mile southwest of the project site and immediately east of the upper mesa eastern face. The view is to the northeast and is depicted in **Visual Resources Figure 2A**. This location provides an open and unobstructed view of the site. The foreground to middleground terrain is flat and supports sparse desert scrub vegetation. The existing BEP I is the dominant feature in the landscape. The project would be visible in the foreground along with a number of existing transmission line structures, the Blythe Substation, and BEP I, which is the dominant feature in the landscape. To the east, the Dome Rock Mountains are visible as distant background elements.

Visual Quality

Just after descending the upper tier of the mesa, the view to the east and northeast from I-10 encompasses middleground to background panoramic scenes of a broad, level, desert mesa landscape lacking distinctive features and containing energy transmission infrastructure, roadside signage, and irrigated orchards. The most prominent foreground to middleground landscape features swaths of dark pavement that comprise I-10. The distant Dome Rock Mountains provide a backdrop of angular landforms. The general lack of scenic features or elements of visual interest, combined with the presence of BEP I, numerous transmission line structures, utility poles, and Blythe Substation contribute to a low-to-moderate rating for visual quality.

Viewer Concern

Viewer expectations at this location are conditioned by the vicinity landscape along I-10 which includes, unobstructed, panoramic landscapes, the presence of numerous electric transmission structures, Blythe Substation, and occasional geometric block forms such as the existing commercial establishment and facilities adjacent to the airport (which are not visible from KOP 1) and BEP I. Views also include the high traffic volumes and large trucks with containers of rectangular block form on I-10. Of the approximately 16,300 to 17,100 motorists per day on I-10, about 40 percent are heavy trucks (BEP II 2002a, p. 7.5-5). Overall viewer sensitivity is rated low-to-moderate.

Viewer Exposure

In spite of an indirect view, site visibility is high in that the view of the site from KOP 1 is from a slightly elevated perspective and is generally unobstructed at a foreground viewing distance. The number of viewers is high and the view duration for eastbound motorists on I-10 would be moderate. The high visibility and numbers of viewers and moderate duration of view would contribute to moderate-to-high viewer exposure.

Overall Visual Sensitivity

For viewers at KOP 1, the low-to-moderate visual quality and viewer concern, combined with a moderate-to-high viewer exposure result in an overall moderate visual sensitivity of the visual setting and viewing characteristics.

KOP 2 – Eastbound Hobsonway

KOP 2 was selected to characterize the visual impact to eastbound traffic on Hobsonway. KOP 2 is located on Hobsonway, near a residence that is located on the eastern face of the mesa's upper tier, approximately 0.4 mile west of the project site. The view is to the east-northeast and is depicted in **Visual Resources Figure 3A**. This location provides a slightly elevated view over the site that is open and unobstructed. The foreground to middleground terrain is flat and supports sparse desert scrub vegetation. The project would be visible within the primary cone of vision in the foreground along with a number of existing transmission line structures, the recently completed BEP I, Blythe Substation, and the paved lanes of Hobsonway. Other roadside utility poles are visible as they transition from the foreground to background away from the viewer along the north side of Hobsonway. To the east, the Dome Rock Mountains are visible as distant background elements.

Visual Quality

Views to the east-northeast from KOP 2 and the adjacent residence encompass foreground to background panoramic scenes of a broad, level, desert mesa landscape lacking distinctive features and containing a prominent energy generation facility (BEP I) and transmission infrastructure. The most prominent landscape features are the recently constructed BEP I with its industrial character and the narrow, linear ribbon of gray pavement that comprises Hobsonway. Portions of the Palo Verde Valley are visible in the background and the distant Dome Rock Mountains provide a backdrop of angular landforms that add some visual variety and interest. The tan desert soils and dark greenish-brown desert scrub vegetation are the dominant coloration in a landscape generally lacking vivid coloration or color contrast. The limited visibility of scenic features and elements of visual interest combined with the presence of BEP I, numerous transmission line structures, utility poles, and Blythe Substation contribute to a low-to-moderate rating for visual quality.

Viewer Concern

Viewer expectations at this location are conditioned by the vicinity landscape along Hobsonway, which includes a panoramic landscape of prominent energy generation and transmission infrastructure and occasional geometric block forms such as the existing commercial establishment and facilities adjacent to the airport (which are not visible from KOP 2). Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. However, any increase in industrial character would be seen as an adverse visual change. Viewer sensitivity is rated low-to-moderate for motorists on Hobsonway.

Viewer Exposure

Site visibility is high in that the view of the site from KOP 2 is slightly elevated and generally unobstructed at a foreground viewing distance. While the number of viewers

is low, the view duration for eastbound motorists on Hobsonway would be extended with a direct angle of view. The high visibility and extended duration of view would be somewhat moderated by the low numbers of viewers. Therefore, viewer exposure would be moderate-to-high for motorists on Hobsonway.

Overall Visual Sensitivity

For eastbound motorists at KOP 2, the low-to-moderate visual quality and viewer concern, combined with moderate-to-high viewer exposure, result in an overall moderate visual sensitivity.

KOP 3 – Mesa Verde (Nicholls Warm Springs)

KOP 3 was selected to capture the potential visual impact to the nearest major residential area. The Mesa Verde (Nicholls Warm Springs) residential subdivision is located south of Blythe Municipal Airport, adjacent, and to the south of, I-10. KOP 3 was established on the north side of the subdivision at a distance of approximately 2.5 miles southwest of the project site. A number of residences along the north and east perimeter of the subdivision would have distant, indirect views of the proposed project. The viewshed to the northeast from KOP 3 includes the characteristic sparsely vegetated, tan-colored desert landscape in the foreground to middleground, a few structures on the north side of I-10 adjacent to the airport, and several transmission lines extending across the flat desert landscape and the recently completed BEP I. The Blythe Substation is barely discernible in the background (see **Visual Resources Figure 4A**).

Visual Quality

Views to the northeast from the north side of the Mesa Verde residential subdivision encompass foreground to background panoramic scenes of a broad, level, desert mesa landscape with a dominant monotone tan coloration and lacking distinctive features. I-10 features prominently in the foreground to middleground landscape. The viewshed is typical of the region and is punctuated by energy transmission infrastructure and facilities associated with Blythe Municipal Airport. Noticeable at a distance is the complex industrial appearance of BEP I. Though barely visible above the horizon, the distant Big Maria and Dome Rock Mountains provide a faint backdrop of angular landforms of lavender coloration. The lack of vivid coloration and the limited visibility of scenic features and color contrast, or elements of visual interest, combined with the presence of energy and transportation infrastructure contribute to a low-to-moderate rating for visual quality.

Viewer Concern

Although residential uses are generally attributed a high degree of viewer concern, viewer concern is also conditioned by existing landscape characteristics and quality, visibility, and primary view direction. At the Mesa Verde Subdivision, most primary (front of residence) views along the north and east side of the subdivision (represented by KOP 3) are directed to the south and west away from the direction of the proposed project. Also, the project is located at a substantial distance from the subdivision, thus reducing project visibility. Furthermore, between the project and the subdivision is I-10 with a continuous flow of vehicles, many of which are large tractor-trailers with large

containers of rectangular, geometric form. Also present in northern views from the subdivision are structures on the north side of I-10 in close proximity to Blythe Airport. Views in the direction of the proposed project encompass numerous built features including BEP I, thus, tempering viewer expectations and lowering viewer concern to a moderate level at KOP 3.

Viewer Exposure

Project visibility is low due to the substantial distance between KOP 3 and the proposed project and the partial screening that occurs from a continual stream of vehicles on I-10, which intervenes between the viewer and the project site. The low project visibility at this background viewing distance combined with the low-to-moderate number of viewers with potentially extended views results in an overall moderate viewer exposure at KOP 3.

Overall Visual Sensitivity

From the north side of the Mesa Verde residential development, the low-to-moderate visual quality combined with moderate viewer concern and moderate viewer exposure, lead to a moderate overall visual sensitivity of the visual setting and viewing characteristics.

KOP 4 – Central Blythe

KOP 4 is located adjacent, and to the north of, Hobsonway on the "C" Canal east levee adjacent to the K-Mart Store parking lot. This location is approximately four miles east of the project site and was selected to depict the closest view of the site from the City of Blythe urban center. The view from KOP 4 is panoramic, encompassing agricultural fields, the irrigation canal, Hobsonway, roadside utility infrastructure on wood poles that transition from the foreground to background, Palo Verde Mesa, and the McCoy Mountains in the distant background (see **Visual Resources Figure 5A**). The view to the site from KOP 4 would be direct though completely obscured by intervening vegetation.

Visual Quality

Views to the west from KOP 4 encompass foreground to middleground views of a landscape that has been substantially altered for agricultural, irrigation, transportation, and communication purposes. The viewshed is panoramic, providing scenes of broad, level agricultural fields and adjacent utility infrastructure, which is typical of the characteristic rural/cropland landscape common to the Palo Verde Valley. The distant McCoy Mountains provide a faint lavender backdrop of angular forms, adding some visual variety though they appear low on the horizon. The green color of the agricultural fields is the dominant, though transient, coloration, which changes with crop stage. However, the lack of vivid coloration, and the limited visibility of scenic features and elements of visual interest as well as the prominence of Hobsonway and roadside utility poles, contribute to a low-to-moderate rating for visual quality.

Viewer Concern

KOP 4 is located on the western edge of the urban center of Blythe. Viewers at this location are generally accessing commercial facilities or are in transit to other short-

range destinations that are typically not considered visually sensitive activities or uses. Viewer expectations at this locale include the transitional landscapes between urban and rural settings that include various forms of infrastructure as well as agricultural and commercial uses. Although there are several residences in the vicinity of KOP 4 (primarily along Hobsonway), the residences do not have unobstructed views of the site since they generally face north or south toward Hobsonway and not to the west. Overall viewer concern is low.

Viewer Exposure

Site visibility is low at a background viewing distance, which along with a brief-to-moderate duration of view, offsets the moderate-to-high number of viewers at this location, leading to moderate viewer exposure.

Overall Visual Sensitivity

The low-to-moderate visual quality and low degree of viewer concern, combined with a moderate degree of viewer exposure result in a low-to-moderate overall viewer visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 4.

KOP 5 – Blythe Municipal Golf Course & Residences

KOP 5 was selected to characterize the impact to the Blythe Municipal Golf Course and the adjacent residences, all of which are located on Palo Verde Mesa and have a direct, though distant (at approximately 4.5 miles), line of sight to the proposed plant site. KOP 5 is located in a small parking area adjacent to the Golf Course and several residences at the edge of the mesa (see **Visual Resources Figure 6A**).

This location provides a panoramic view to the south and southwest, encompassing the Palo Verde Valley in the foreground and middleground and the project site in the background. The Mule and Little Chuckwalla Mountains provide a distant backdrop to the site. The foreground to middleground terrain is flat and supports sparse desert scrub vegetation and a few irrigated agricultural parcels. Also visible in the distance is the City of Blythe, the airport, the Blythe Substation, numerous electric transmission lines that cross the site, and BEP I. At this distance, BEP I, the substation, and transmission lines are barely discernible. The view to the site from several residences and several of the golf course fairways and greens would be direct and extended.

Visual Quality

The panoramic views to the south and southwest overlook the Palo Verde Valley and Palo Verde Mesa. These vista views also encompass the mountains that ring the area. Though much of the foreground to middleground landscape is dominated by agricultural fields and monotone desert scrub vegetation, the elevated perspective available from this KOP provides visual access to a regional landscape that offers more distinctive features with greater visual variety and interest. The color contrast of the tan soils and vegetation with the vivid green of irrigated croplands and the lavender of distant mountain ranges add to a more visually interesting landscape. Also, barely discernible at this background distance is BEP I. Visual quality from KOP 5 is rated moderate-to-high.

Viewer Concern

Residences in the Mesa Bluffs area are situated along the mesa edge to take advantage of the vistas overlooking the Palo Verde Valley and Mesa. Also, the recreational users of the Municipal Golf Course (approximately 36,000 rounds of golf are played annually – BEP II 2002a, p. 7.5-7) have expectations for panoramic views and a predominantly naturally appearing landscape. Therefore, the viewers in the Mesa Bluffs area are considered to be sensitive to landscape changes and viewer concern is rated moderate-to-high.

Viewer Exposure

Site visibility is low due to the substantial distance between the golf course/Mesa Bluffs area and the project site. Though the number of potential viewers at the golf course is moderate, the site would only be visible from a few of the fairways and greens and would generally not be noticeable given the distance and indirect angle of view. The adjacent residences would have more direct viewing opportunities but again, the distance would generally limit project visibility. However, the low project visibility would offset the extended duration of view available to residents and golfers alike. Therefore, viewer exposure is low-to-moderate.

Overall Visual Sensitivity

For viewers along Mesa Bluffs, the moderate-to-high visual quality and viewer concern combined with the low-to- moderate viewer exposure, lead to a moderate-to-high assessment for overall visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 5.

KOP 6 – Westbound Hobsonway

KOP 6 was selected as one of two locations to characterize the impact to motorists on Hobsonway. KOP 6 is located on westbound Hobsonway at the southeast corner of the project site and captures the view of the site available to westbound motorists (see **Visual Resources Figure 7A**).

This location provides a panoramic view to the north and west encompassing the project site in the foreground and the Little Maria and Big Maria Mountains as distant background elements. The foreground to middleground terrain is flat and dominated by BEP I. The foreground landscape is also crossed by numerous electric transmission lines. Due to the close proximity of the site to Hobsonway, the site is located within the primary cone of vision of westbound travelers on Hobsonway.

Visual Quality

Views to the north and west from Hobsonway encompass foreground to middleground panoramic scenes of a highly modified desert mesa environment that is dominated by energy generation and transmission infrastructure. While the immediate foreground lacks scenic features or elements of visual interest, the angular landforms of the distant Little Maria and Big Maria Mountains add some visual variety and interest though they appear low on the horizon. Portions of these features are blocked from view by the industrial forms of BEP I. The lack of vivid coloration, and the limited visibility of scenic features and elements of visual interest, combined with the dominant presence of BEP I

and numerous transmission line structures, and Blythe Substation result in a low-to-moderate rating for visual quality.

Viewer Concern

Viewer expectations along this portion of Hobsonway are conditioned by the vicinity landscape and must now consider the prominent presence of BEP I along with the numerous electric transmission line structures and Blythe Substation. Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. Overall viewer concern is rated low-to-moderate.

Viewer Exposure

As previously stated, the proposed site is located within the primary cone of vision of travelers on Hobsonway and visibility would be high at this foreground viewing distance. Although the number of viewers would be low, the duration of view would be moderate to high. The overall viewer exposure would be moderate.

Overall Visual Sensitivity

For westbound motorists on Hobsonway, the low-to-moderate visual quality and viewer concern, combined with moderate viewer exposure result in a low-to-moderate visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 6.

KOP 7 – Westbound I-10

KOP 7 was selected as one of two locations to characterize the impact to motorists on I-10. KOP 7 is located on westbound I-10, approximately 0.4-mile southeast of the project site and captures the view of the site available to westbound motorists (see **Visual Resources Figure 8**).

This location provides a panoramic view to the northwest encompassing the project site in the foreground with the prominent BEP I in the near middleground, and the Little Maria and Big Maria Mountains as distant background elements. The foreground landscape is also crossed by numerous electric transmission lines. The site is visible within the primary cone of vision of westbound travelers on I-10.

Visual Quality

Views to the northwest from I-10 encompass foreground to middleground panoramic desert mesa scenes with prominent energy generation and transmission infrastructure. While the immediate foreground lacks scenic features or elements of visual interest, the angular landforms of the distant Little Maria and Big Maria Mountains add some visual variety and interest though they appear low on the horizon. A small portion of the mountains in the background are blocked from view by the industrial forms of BEP I. The lack of vivid coloration, and the limited visibility of scenic features and elements of visual interest, combined with the dominant presence of BEP I, numerous transmission line structures, and Blythe Substation result in a low-to-moderate rating for visual quality.

Viewer Concern

Viewer expectations along this portion of I-10 are conditioned by the adjacent landscape and must now consider the prominent presence of the recently completed BEP I along with the numerous electric transmission line structures and Blythe Substation. Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. Overall viewer concern is rated low-to-moderate.

Viewer Exposure

As previously stated, the proposed site is located within the primary cone of vision of travelers on I-10 and visibility would be high at this foreground viewing distance. The peak month average daily traffic (ADT) for the month of heaviest traffic flow at the intersection Junction Route 78 south/Neighbors Boulevard on I-10 is 26,000 vehicles according to Caltrans information.[2] The number of viewers would be high and the duration of view would be moderate. The overall viewer exposure would be moderate-to-high.

Overall Visual Sensitivity

For westbound motorists on I-10, the low-to-moderate visual quality and viewer concern combined with moderate viewer exposure result in a moderate visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 7.

DIRECT AND INDIRECT IMPACTS

This analysis considers the potential impacts of the proposed project in relation to the four significance criteria for visual resource impacts listed in Appendix G of the CEQA Guidelines, under Aesthetics, specified below.

Scenic Vistas

CEQA Significance Criteria #1. “Would the project have a substantial adverse effect on a scenic vista?”

Although panoramic vistas are available to users of the Blythe Municipal Golf Course and to the adjacent residences at Mesa Bluffs, there are no recognized scenic vistas in the project viewshed. Therefore, the project would not cause significant visual impacts in regard to this criterion.

Scenic Resources

CEQA Significance Criteria #2. “Would the project substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?”

The foreground to middleground mesa landscape consists primarily of desert scrub vegetation with a substantial amount of electric transmission infrastructure and other built features (including roads and structures). Views from the nearby residences off of Hobsonway and from Hobsonway and I-10 are not considered scenic. The project site is

[2] Caltrans, 2003 Traffic and Vehicle Data Systems Unit website: http://traffic-counts.dot.ca.gov/

not within a designated State scenic highway. Therefore, the project would not cause significant visual impacts in regard to this criterion.

Visual Character or Quality

CEQA Significance Criteria #3. "Would the project substantially degrade the existing visual character or quality of the site and its surroundings?" The project aspects that were evaluated under this criterion include project construction, the power plant structures, the various linears, and visible water vapor plumes.

Construction Impacts and Mitigation

Project Construction

The construction of the proposed power plant would cause visual impacts. Construction would include site clearing and grading, construction of the actual facilities, and site cleanup and restoration. Construction would involve the use of cranes, heavy construction equipment, temporary storage and office facilities, and temporary laydown/staging areas. Parking and use of numerous pieces of equipment, the storage of building materials, and the presence of a construction workforce, etc; and other construction activities would take-place on BEP II site for an approximate 18-22 month construction period. Traffic would also increase along Hobsonway during construction. Construction activities would be visible from Hobsonway, nearby residences, and I-10 which is the primary travel corridor in the region.

Proper implementation of staff's proposed mitigation in Condition of Certification **VIS-1** and **VIS-3** would ensure that the visual impacts associated with project construction remain less than significant. It is also anticipated that construction activity will take place at night. In order to ensure that significant construction lighting impacts do not occur, staff recommends mitigation in Condition of Certification **VIS-2**.

Linear Facilities

The installation of new aboveground electric and underground gas linear facilities to serve BEP II would take place within the 152-acre industrial area where the Buck Boulevard Substation and BEP I are built. An approximate 2,500-foot long overhead transmission line is to connect BEP II with the Buck Boulevard Substation. The transmission line span will require the installation of three 125-foot tall transmission towers.

The 152 acre industrial area is supplied natural gas from an interconnection with the El Paso Gas System that currently supplies the existing BEP I. This interconnection will also serve the proposed BEP II. An underground natural gas pipeline is to be constructed from the existing interconnect to a proposed interconnect on BEP II site.

Raw water supply for all BEP II uses will be provided from two 3,000 gallons per minute groundwater wells to be constructed on the plant site.

Proper implementation of staff's proposed mitigation in Condition of Certification **VIS-1** would ensure that the visual impacts associated with linear facilities construction remain less than significant.

Operation Impacts and Mitigation

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 **VISUAL RESOURCES Appendix VR-1**. The visible plume modeling analysis is discussed in **VISUAL RESOURCES Appendix VR-5**.

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.

Power Plant Structures

The proposed project would result in the addition of sizable geometric structures with industrial character to an undeveloped parcel immediately adjacent and southwest of BEP I (see **PROJECT DESCRIPTION**).

KOP 1 – Eastbound I-10

Visual Resources Figure 2B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 1 on eastbound I-10. The most obvious change to the landscape would be the addition of the complex geometric structures comprising the power plant facilities.

Visual Contrast

The proposed project would add prominent industrial features to the foreground landscape including the geometric forms and complex lines of the HRSG structures, stacks, and cooling tower. While these structural characteristics and neutral colors would be consistent with the forms, lines, and colors established by the existing BEP I facilities, the industrial characteristics of the proposed BEP II structures would be more noticeable compared to the existing facilities given the closer proximity of the proposed project to I-10. The resulting visual contrast would be low-to-moderate (see **Visual Resources Appendix VR-1**).

Project Dominance

As illustrated in **Visual Resources Figure 2B**, compared to the existing BEP I facilities, the proposed project would appear larger in scale (though not so large as to dominate BEP I) given the closer proximity of the proposed project to I-10. The proposed project would also appear comparable in prominence to the broad, horizontal forms of the foreground desert mesa and I-10, and the angular forms of the background mountains. The proposed power plant facilities would appear spatially prominent in the primary cone of vision, and the extension of the HRSG stacks and structures above the horizon line would contribute to the project's structural prominence. Overall project dominance would be co-dominant.

View Blockage

From the vicinity of KOP 1, the HRSG structures and stacks and cooling tower (lower quality landscape features) would block from view portions of the background

mountains and sky (higher quality landscape features) as well as portions of the existing BEP I (similar quality feature - though only briefly from the specific eastbound I-10 location illustrated in Figure 2B). The resulting view blockage would be low-to-moderate.

Overall Visual Change

From KOP 1, the values for visual contrast, project dominance, and view blockage, when taken together, constitutes a low-to-moderate level of overall visual change.

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 1 would cause an adverse but less than significant visual impact with the effective implementation of Conditions of Certification **VIS-4** and **VIS-5**. The implementation of these Conditions of Certification would minimize the visual intrusiveness, and ensure that BEP II structures are surface treated, and landscaped consistent with the viewshed as proposed and analyzed.

KOP 2 – Eastbound Hobsonway

Visual Resources Figure 3B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 2 on eastbound Hobsonway and an adjacent residence, approximately 0.4-mile west of the project site. The most obvious change to the landscape would be the visibility of the HRSG structures and stacks and the eight-cell cooling tower.

Visual Contrast

The proposed project would add a prominent industrial facility to the foreground landscape. While the neutral colors and complex geometric forms and lines of the HRSG structures, stacks, and cooling tower would be consistent with the forms, lines, and colors established by the existing BEP I facilities, they would contrast with the simple horizontal landforms of the mesa landscape. The resulting visual contrast would be moderate-to-high (see **Visual Resources Appendix VR-1**).

Project Dominance

The proposed project would be spatially prominent in the primary cone of vision of eastbound travelers on Hobsonway and the nearby residence. The mass and scale of the proposed structures would appear substantially greater than the existing BEP I structures and the project would appear more prominent than the distant Big Maria and Dome Rock mountain ranges given the close proximity of BEP II to Hobsonway and KOP 2. The solid massing of the geometric block structures and the structure skylining would increase the prominence of the proposed project. As a result, the proposed project would appear dominant to the existing natural landforms and built features.

View Blockage

From KOP 1, the HRSG structures and stacks and cooling tower (lower quality landscape features) would block from view noticeable portions of the Dome Rock

Mountains to the east and sky (higher quality landscape features). The 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 moderate-to-high degree of visual contrast, dominant project structures, and moderate degree of view blockage caused by project structures.

Visual Impact Significance

When considered within the context of the overall moderate visual sensitivity of the existing visual landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 2 would cause adverse but less than significant visual impact with the effective implementation of Conditions of Certification **VIS-4** and **VIS-5**. The implementation of these Conditions of Certification will minimize the visual intrusiveness, and ensure that BEP II structures are architecturally screened, surface treated, and landscaped consistent with the viewshed as proposed and analyzed.

KOP 3 – Mesa Verde

Visual Resources Figure 4B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 3 on the north side of the Mesa Verde residential subdivision, approximately 2.5 miles southwest of the project site. The geometric block forms of the proposed power plant facilities are visible to the right of the existing BEP I facilities.

Visual Contrast

The proposed project would add the slightly noticeable geometric forms and complex lines of the HRSG structures, stacks, and eight-cell cooling tower to the existing landscape. From the vantage point of KOP 3, these structural characteristics would generally be consistent with existing forms and lines established by BEP I structural features though inconsistent with the more horizontal to irregular forms and lines of the mesa landforms and vegetation respectively. The neutral color of the proposed facilities would also be consistent with the color of the existing BEP I facilities. The resulting visual contrast would be low (see **Visual Resources Appendix VR-1**).

Project Dominance

The most prominent landscape feature in foreground to middleground views from KOP 3 is the broad mesa landform. At the KOP 3 viewing distance of approximately 2.5 miles, the barely noticeable geometric, block forms of the proposed project would appear as subordinate, background features in the landscape.

View Blockage

As viewed from KOP 3, the small profile of the proposed project and minimal skylining that would occur would result in a low degree of view blockage.

Overall Visual Change

From KOP 3, the values for visual contrast, project dominance, and view blockage, when taken together, constitutes a low level of overall visual change.

Visual Impact Significance

When considered within the context of the moderate visual sensitivity of the existing landscape and viewing characteristics, the low visual change that would be perceived from KOP 3 would not result in a significant visual impact with effective implementation of Conditions of Certification **VIS-4** and **VIS-5**.

KOP 4 – Central Blythe

Visual Resources Figure 5B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 4 adjacent to the "C" Canal Levee at Hobsonway, approximately four miles east of the project site near central Blythe. From this location, the proposed project facilities would not be discernible in the landscape due to the screening provided by intervening vegetation.

Visual Contrast

No visual contrast would occur since the proposed project facilities would not be discernible from this KOP (see **Visual Resources Appendix VR-1**).

Project Dominance

Because the proposed project components would not be visible at this location, project dominance would be rated none.

View Blockage

From KOP 4, there would be no view blockage since the project components would not be visible.

Overall Visual Change

From KOP 4, there would be no visual change because of the lack of project visibility.

Visual Impact Significance

From KOP 4, no significant visual impacts are anticipated given the lack of project visibility due to the substantial viewing distance and the screening provided by intervening vegetation.

KOP 5 – Blythe Municipal Golf Course and Residences

Visual Resources Figure 6B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 5 at the Blythe Municipal Golf Course and adjacent residences. The geometric block forms of the proposed power plant facilities would be slightly noticeable on the mesa horizon as a low rectangular structure with a vertical component extending above. At a distance of approximately 4.5 miles, no other project

components (transmission lines, switchyard, and evaporation ponds) would be discernible.

Visual Contrast

The proposed project would be barely discernible as background geometric block and linear forms. To the extent they are visible, the structural characteristics would be consistent with BEP I features and overall visual contrast as experienced from KOP 5 would be low (see **Visual Resources Appendix VR-1**).

Project Dominance

The most prominent landscape features in foreground to middleground views from KOP 5 are the broad landforms of the valley floor and mesa. The background is dominated by the distant angular forms of the Mule, Palo Verde, and Little Chuckwalla Mountains. At the KOP 5 viewing distance of approximately 4.5 miles, the geometric, block forms of the proposed project would appear small in size in the wide field of view, similar to BEP I, and subordinate in relation to the level valley and mesa and mountainous backdrop.

View Blockage

As viewed from KOP 5, the small profile of the proposed project would result in minimal blockage of the mountain backdrop and overall view blockage would be low.

Overall Visual Change

From KOP 5, the overall visual change caused by the proposed project would be low due to the low degree of contrast and view blockage that would result from the project's visually subordinate structures.

Visual Impact Significance

When considered within the context of the overall moderate-to-high visual sensitivity of the existing landscape and viewing characteristics, a low visual change, and would not generate a significant visual impact.

KOP 6 – Westbound Hobsonway

Visual Resources Figure 7B presents (at life-size scale when viewed at a normal reading distance of approximately 18 inches) a visual simulation of the proposed project as viewed from KOP 6 on westbound Hobsonway at the intersection of Hobsonway and Buck Boulevard. The most obvious change to the landscape would be the visibility of the HRSG structures and stacks and the eight-cell cooling tower.

Visual Contrast

The proposed project would add a prominent industrial facility to the foreground landscape. While the neutral colors and complex geometric forms and lines of the HRSG structures, stacks, and cooling tower would be consistent with the forms, lines, and colors established by the existing BEP I facilities, they would contrast with the simple horizontal landforms of the mesa landscape and irregular forms and lines of the background mountain ranges. The resulting visual contrast would be moderate-to-high (see **Visual Resources Appendix VR-1**).

Project Dominance

The proposed industrial facilities would be spatially prominent in the primary cone of vision of westbound travelers on Hobsonway. The structural mass and scale would appear larger than BEP I and equally prominent compared to the background mountain ranges due to the proposed project's close proximity to Hobsonway. The solid massing of the geometric block structures and the structure skylining would increase the prominence of the proposed structures in the wide field of view. As a result, the proposed project would appear co-dominant to dominant in the context of the existing natural landforms and built features.

View Blockage

From KOP 6, project structures (lower quality landscape features) would block from view a substantial portion of the background mountain range (higher quality landscape feature). The resulting view blockage would be moderate.

Overall Visual Change

From KOP 6, the overall visual change caused by the proposed project would be moderate-to-high due to the moderate-to-high degree of visual contrast, co-dominant-to-dominant project dominance, and moderate view blockage that would result from the project's structures.

Visual Impact Significance

When considered within the context of the overall low-to-moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 6 would cause an adverse but less than significant visual impact with effective implementation of Conditions of Certification **VIS-4** and **VIS-5**. The implementation of the Conditions of Certification will minimize the visual intrusiveness, and ensure that BEP II structures are surface treated, and that landscaping is consistent with the viewshed as proposed and analyzed.

KOP 7 – Westbound I-10

The most obvious change to the landscape would be the addition of the structurally complex HRSG structures and stacks and the eight-cell cooling tower.

Visual Contrast

The proposed project would add a prominent industrial facility to the foreground landscape. While the neutral colors and complex geometric forms and lines of the HRSG structures, stacks, and cooling tower would be consistent with the forms, lines, and colors established by the existing BEP I facilities, they would contrast with the simple horizontal mesa landform and irregular forms and lines of the background mountain ranges. The resulting visual contrast would be moderate-to-high (see **Visual Resources Appendix VR-1**).

Project Dominance

The proposed industrial facilities would be spatially prominent in the primary cone of vision of westbound travelers on I-10. The mass and scale of the proposed structures

would appear greater than the existing BEP I structures and equally prominent compared to the background mountain ranges given the closer proximity of BEP II to I-10. The solid massing of the complex, geometric block structures and the structure skylining would increase the prominence of the proposed structures in the wide field of view. As a result, the proposed project would appear co-dominant to dominant in the context of the existing natural landforms and built features.

View Blockage

From KOP 7, project structures (lower quality landscape features) would block from view a substantial portion of the background mountain range (higher quality landscape feature). The resulting view blockage would be moderate in the wide field of view.

Overall Visual Change

From KOP 7, the overall visual change caused by the proposed project would be moderate-to-high due to the moderate-to-high degree of visual contrast, co-dominant to dominant project dominance, and moderate view blockage that would result from the project's structures.

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 7 would cause an adverse but less than significant visual impact with the effective implementation of Conditions of Certification **VIS-4** and **VIS-5**. The implementation of these Conditions of Certification will minimize the visual intrusiveness, and ensure that BEP II structures are surface treated, and that landscaping is consistent with the viewshed as proposed and analyzed.

Lighting Or Glare

CEQA Significance Criteria #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.

At present, the most prominent sources of light in the vicinity of BEP II site are the adjacent BEP I facility and the nearby motor vehicle lights on I-10. In regard to exterior lighting, the applicant has stated the following:

> "The lighting system will provide illumination for plant operation under normal conditions and also emergency lighting to perform manual operations during outage of the normal power source. The lighting system will include high pressure (HP) sodium light sources for outdoor installations. A low visibility lighting scheme using shielded, high cut-off angle fixtures will be utilized to minimize the nighttime impact [on] nearby properties.

The area lighting system will provide illumination for the performance of general outdoor yard tasks, safety, plant security and general site roadway access and will consist of HP sodium luminaries and support poles. Access roads from Buck Boulevard through the plant will be illuminated. The applicant has agreed with the City of Blythe to provide street lighting along Buck Boulevard and Hobsonway" (BEP II 2002a, pp. 7.5-17-18).

Although lighting of project facilities would not be required under FAA guidelines, the Applicant has decided to install FAA approved lighting at the tops of the HRSG exhaust stacks (BEP II 2002a, p. 7.5-17).

In order to control lighting impacts, the applicant has indicated that the lighting system would be designed to minimize its impact on surrounding areas and would include such control measures as timers, sensors, and/or switches to keep lights off when they are not needed (BEP II 2002a, pp. 7.5-17-18).

Project night lighting would be visible from several of the KOPs and their represented areas (KOPs 1, 2, 3, 5, 6, and 7). Given the limited amount of night lighting in the vicinity of the power plant site, the proposed project lighting has the potential to further change the character of the existing landscape at night both during construction and operation of the project, potentially resulting in significant visual impacts. Even shielded lighting elements could create significant light and glare impacts as a result of indirect lighting of project structures and backscatter if not properly managed. Proper implementation of staff's proposed mitigation in Condition of Certification **VIS-6** would ensure that the visual impacts associated with operational lighting remain less than significant.

The simulations of the proposed facility provided by the applicant show the utilization of a surface treatment for major project structures, buildings, and tanks in the public view that will use a finish that will not create excessive glare and will minimize visual intrusion and contrast. With the applicant's commitment to treat project structures in a manner that minimizes visual contrast and glare, the project would not be a source of substantial glare that could adversely affect views. Staff proposes Condition of Certification **VIS-4**, which would require review and approval by the Energy Commission staff of a surface treatment plan for the project structures to ensure that the measures proposed by BEP II are properly implemented. With the mitigation measures proposed by the applicant and staff, BEP II would not be a source of substantial glare that could adversely affect daytime views in the project vicinity.

Linear Facilities

The proposed linear facilities interconnections would not result in significant visual impacts. The installation of new above-ground electric and underground gas linear facilities to serve the BEP II would take place within a 152-acre industrial area where the Buck Substation and BEP I are built, and adjacent to the location where the BEP II is to be constructed. The operation of the on-industrial-site linear facilities for the BEP II would present a less than significant visual effect.

Visible Plume Modeling Analysis

Please refer to **Appendix VR-5** at the end of the visual resources section for a more complete description of staff's Visible Plume Modeling Analysis. Staff has determined that visible plumes from the BEP II project will not exceed Energy Commission staff's 20 percent standard. Visible plumes occurring less than 20 percent are considered to be less than significant.

CUMULATIVE IMPACTS

As defined in Section 15355 of the CEQA Guidelines (California Code Regulation, Title 14), a cumulative impact is created as a result of the combination of the project under consideration together with other existing or reasonably foreseeable projects causing related impacts. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time. In other words, though any one project in a given area may not create a significant impact to visual resources, the combination of the new project with all existing or planned projects in the area may create significant impacts. 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; or (3) visual quality is diminished.

VISUAL RESOURCES Table 2 lists three projects that have been identified for cumulative impact analysis – the existing BEP I, the proposed BEP Transmission Line Amendment Project (BEPTL), and the Desert Southwest Transmission Project (DSWTP) (includes both the proposed Hobsonway Substation and the transmission line).

VISUAL RESOURCES Table 2
List of Cumulative Projects (Existing & Proposed)

Project	Description	Visible in Proposed Project Field of View	Cumulative Impact and Significance
Blythe Energy Project I	Existing Combined-Cycle Power Plant	YES KOPs 1, 2, 3, 5, 6, and 7 ---------- NO KOP 4	An industrial feature of the Desert Mesa landscape.
Blythe Energy Project Transmission Line Project Amendment	Buck Substation to Julian Hinds Substation. The route would parallel existing facilities in the I-10 corridor.	PARTIALLY KOPs 1, 2, 3, 6, and 7	Introduction of substantial structural visual contrast into the Desert Mesa landscape visible from I-10.
Blythe Energy Project II	Proposed Combined-Cycle Power Plant	YES KOPs 1, 2, 3, 5, 6, and 7 ---------- NO KOP 4	Substantial increase in industrial features of the Desert Mesa landscape.

Desert Southwest Transmission Project: Hobsonway Substation	A 230 or 500 kV Transmission Line Substation to be located immediately adjacent and to the west of BEP II.	YES KOPs 1, 2, 3, 5, 6, and 7 ---------- NO KOP 4	Substantial increase in industrialization of the Desert Mesa landscape.
Desert Southwest Transmission Line Project: Proposed Transmission Line Route	A proposed 118-mile 230 or 500 kV Transmission Line extending from the proposed Hobsonway Substation to the existing Devers Substation north of Palm Springs. The route would parallel existing facilities in the I-10 corridor for much of the route	PARTIALLY KOPs 1, 2, 3, 6, and 7	Introduction of substantial structural visual contrast into the desert landscape visible from I-10 between Desert Center and the route's I-10 crossing just east of the Cactus City Rest Area.

BEP II would be visible within the same field of view as BEP I and would make a substantial additional contribution to the visual impact resulting from BEP I. BEP II is closer than BEP I to Hobsonway, a nearby residence, and I-10. As a result, BEP II would appear larger in scale and more prominent.

The proposed Blythe Energy Project Transmission Line (BEPTL) from the Buck Substation to the Julian Hinds Substation would be adjacent to the existing SCE DPV-1 500-kV line within a designated U.S. Bureau of Land Management utility corridor. Two other transmission lines are proposed within the same utility corridor; the SCE DPV-2 and the DSWTP 500 kV. The specific location of the proposed DSWTP 500 kV has not been identified. The proposed transmission lines would contribute an industrial character to the I-10 corridor, particularly along the section of I-10 west of Desert Center.

The BEPTL would be 1.5 to 2 miles south from I-10 viewers. This distance and direction helps to minimize the visual cumulative impact to travelers on I-10 and from the BEP II site. The transmission line route passes within the boundary of the Palo Verde Valley Area Plan - Blythe Airport Sphere of Influence Policy Area. The airport property adjoins the project site to the east. The transmission line's design and construction within this plan area is required to comply with applicable airport operation(s) and aviation safety regulations (e.g. non-glare, etc ;).

The existing Blythe Airport, BEP I and SCE DPV-1 500-kV line, and the proposed BEPTL, SCE DPV-2 and DSWTP 500 kV combined would present an expansive area of complex industrial character in an otherwise desert mesa landscape. The visual contrast, structural dominance, and view blockage resulting from the combined existing developments and proposed projects would cause a cumulative visual impact. However, based on the short duration of view for travelers on 1-10 and low number of viewers on Hobsonway, the proposed BEP II's impact when combined with the cumulative impact of other developments both existing and proposed, would not be cumulatively considerable, and thus does not result in a significant cumulative impact to visual resources.

PROPOSED APPLICANT MITIGATION MEASURES

The applicant has proposed seven mitigation measures to be incorporated into the project design to minimize visual impacts associated with the operation of the facility.

Plant facilities will be painted with colors similar to the surrounding desert landscape, principally tan, sand, and buff colors. The colors will help project facilities to harmonize with the surrounding environment.

1. Fencing will be constructed of non-reflective material, treated, or painted to reduce visual effects.
2. Non-reflective surfaces will be used for plant equipment and structures, including transmission line structures, to minimize glare from these facilities.
3. Nighttime lighting on the project site will be limited to areas required for the safety of project personnel and the public.
4. Directional shielding of lights will be installed to prevent significant light, glare, or backscatter illumination visible to sensitive viewpoints.
5. Exposed soils resulting from vegetation clearing during construction must be revegetated after facilities are installed.
6. All construction debris will be removed immediately following completion of power plant and switchyard construction activities.

Energy Commission staff have identified potential significant visual impacts resulting from visibility of project structures and night lighting. Although staff generally agrees with the applicant's proposals to mitigate project structure and lighting impacts, staff's position is that some of these mitigation measures need to be more precisely developed and, in some cases, expanded in conditions of certification to ensure mitigation of these potential impacts to less than significant levels as required by CEQA. Staff has proposed conditions of certification to mitigate potential significant adverse project impacts. Without such conditions staff cannot state that the project would not cause significant visual impacts.

Applicant's Mitigation Measure 1 regarding structure color is included in Condition of Certification **VIS-4**. Applicant's Mitigation Measures 2 and 3 regarding non-reflective surfaces are included in Condition of Certification **VIS-4**. Applicant's Mitigation Measure 4 regarding lighting is included in Condition of Certification **VIS-2** and **VIS-6**. Applicant's Mitigation Measures 5 is included in **VIS-3**. Applicant's Mitigation Measure 6 regarding exposed soils and construction debris are included in Condition of Certification **VIS-1**.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

This analysis considers the consistency or compliance of the proposed project with applicable adopted local LORS specific to visual resources.

Although the proposed power plant and associated linear facilities would be constructed within the jurisdiction of the City of Blythe, the project also generates potential visual

affects to the County of Riverside's jurisdiction. Therefore, the BEP II would be subject to LORS pertaining to visual resources which are found in both the City and County General Plans and their applicable Municipal and Government Codes.

The City of Blythe General Plan has three Elements applicable for this review; the Land Use, Community Design, and the Scenic Highways Elements. Specifically, these Elements provide Community Design, Scenic Highways, Industrial and Public Utilities policies applicable to the proposed BEP II. The Blythe Zoning Code provides applicable zoning provisions for the on-site development of the project.

The Riverside County General Plan includes the Palo Verde Valley Area Plan which provides more specific development policies for the unincorporated area. This plan includes policies for the Blythe Airport and Scenic Corridors.

CITY OF BLYTHE

General Plan(adopted September 1989)

The following visual resources-related policies of the City of Blythe General Plan are applicable to the proposed project:

Industrial Policy 7
"All industrial sites shall be appropriately landscaped and all outdoor storage areas shall be screened from view from public rights-of-way and surrounding properties with a combination of fencing and landscaping;"

Community Design Policy 3
"Areas of special interest, including focal and entry points, scenic highway viewsheds, and landmarks, as identified in the General Plan, will receive special design treatment when part of a development proposal;"

Community Design Policy 9
"Building facades, landscaping, paving, utilities and other components of the streetscape should be combined in a manner which creates a distinctive and pleasing environment and identity for residents and visitors;

Scenic Highways Policy 1
"Scenic highways and corridors identified in the General Plan shall be analyzed and reviewed prior to development to assure the preservation of scenic resources;"

- Scenic Highway Map (Exhibit III-6) shows Hobsonway West, US Interstate 10, Riverside Ave, 14th Ave, Arrowhead Boulevard, and Neighbors Boulevard as proposed "Scenic Highways" in the vicinity of the project.

Scenic Highways Policy 2
"Develop and implement standards for viewshed analysis to assure the preservation and enhancement of natural scenic resources. Areas of special concern include but are not limited to parkways, building setbacks, pad elevations, building height and landscape treatment."

Scenic Highways Policy 8
"Electric substations, pumping stations, city wells, bulk fuel storage facilities, and similar utility infrastructure shall be screened from public view through the provision of decorative walls, landscaping buffers, or other acceptable means of screening;"

Public Utilities Policy 4
"The shared use of major transmission corridors, where feasible, and other appropriate measures shall be encouraged as a means of preserving the aesthetic resources of the City and to lessen the visual impacts of such development;"

Consistency Determination Consistent
The proposed project design would respect the visual characteristics already established in the vicinity. The project introduces new structures to an aesthetically sensitive and scenic valued area. Treatment of all project structures, buildings, and fences are to be treated in appropriate colors or hues that minimize visual intrusion and contrast by blending with the visual landscape. In addition, structures, buildings and fences are to have surfaces that do not create glare, and the property landscaped.

The project's design, surface treatment and landscaping through the effective implementation of the conditions of certification would limit its visual intrusiveness and contrast at this entry point, and within an aesthetically sensitive and scenic valued area. See proposed Conditions of Certifications **VIS-4** and **VIS-5**.

Zone Code Requirements
The following chapters of the City of Blythe Zoning Ordinance are applicable to the on-site construction of the proposed project:

- **Chapter 17.22 Landscaping**. "Landscaping is required in the following locations for all residential, commercial, industrial and public/quasi-public uses:

  A. Throughout required front-yard setbacks and other areas visible from a public right-of-way where not used for parking, access or loading;

  B. Five percent of the parking lot area which is visible from a public right-of-way."

- **Chapter 17.22.040 Commercial, industrial or public quasi-public**. "For every two hundred square feet of landscaping, one tree shall be provided in a tree well sized to accommodate a fifteen-gallon minimum tree. Suitable protection shall be provided to trees and public works from traffic."

- **Chapter 17.22.060 Maintenance**. "Require landscaping shall be maintained in a neat, clean and healthful condition."

  Compliance Determination
  Project would be **compliant** with implementation of **VIS-5 Landscape Screening**.

- **Chapter 17.26.050** On-premises business signs. "Signs erected or used for business purposes and located on a place of business, enterprise or calling and used solely for naming, designating or identifying the business, enterprise, calling, products or services available on or with the premises may be permitted within the following guidelines" for Free-standing Signs and Wall Signs.

Compliance Determination
Project would be **compliant** with implementation of **VIS-7 Signage**.

- **Chapter 17.28.030 Lighting of private property**. "Lighting, where provided to illuminate private property, shall be so arranged as to reflect away from adjoining property or any public way and to be arranged so as not to cause a nuisance either to highway traffic or to the living environment."

  Compliance Determination
  Project would be **compliant** with implementation of **VIS-2 Construction Lighting** and **VIS-6 Permanent Exterior Lighting**.

County of Riverside

The following visual resources related policies of the Riverside General Plan, Palo Verde Valley Area Plan (PVVAP) (adopted October 2003) are applicable to the proposed project:

PVVAP 3.1 "To provide for the orderly development of Blythe Airport and the surrounding area, comply with the Airport Land Use Compatibility Plan for Blythe Airport as fully set forth in Appendix L and as summarized in Table 4, as well as any applicable policies related to airports in the Land Use, Circulation, Safety and Noise Elements of the Riverside County General Plan."

"A. The following uses shall be prohibited in all airport safety zones:

(1) Any use which would direct a steady light or flashing light or red, white, green, or amber colors associated with airport operations toward an aircraft engaged in an initial straight climb following takeoff or toward an aircraft engaged in a straight final approach toward a landing at an airport, other than an FAA approved navigational signal light or visual approach slope indicator.

(2) Any use which would cause sunlight to be reflected toward an aircraft engaged in an initial straight climb following takeoff or toward an aircraft engaged in a straight final approach toward a landing at an airport.

(3) Any use which would generate smoke or water vapor or which would attract large concentrations or birds, or which may otherwise affect safe air navigation within the area."

Consistency Determination Consistent
The project introduces new structures that would be visually sensitive, and maintain visual characteristics that would not interfere with aircraft or airport operations; because the project's design and surface treatment through the effective implementation of the conditions of certification would limit the project's visual intrusiveness within the Blythe Airport Sphere of Influence. See proposed Conditions of Certifications **VIS-4** and **VIS-6**.

For a discussion on air navigation safety pertaining to Blythe Airport, refer to the **TRAFFIC AND TRANSPORTATION** and **BIOLOGICAL RESOURCES** (discussion regarding bird strikes) sections of this Final Staff Assessment.

PVVAP 10.1 "Protect the scenic highways in the Palo Verde Valley planning area from change that would diminish the aesthetic value of adjacent properties in accordance with the Scenic Corridors sections of the General Plan Land Use, Multipurpose Open Space, and Circulation Elements.

Consistency Determination Consistent
The proposed project design would respect the visual characteristics already established in the vicinity. The project introduces new structures to aesthetically sensitive and scenic valued area. Treatment of all project structures, buildings, and fences are to be treated in appropriate colors or hues that minimize visual intrusion and contrast by blending with the visual landscape. In addition, structures, buildings, and fences are to have surfaces that do not create glare.

The project's design, surface treatment, and landscaping through the effective implementation of the conditions of certification would limit its visual intrusiveness and contrast with the existing setting. See proposed Conditions of Certifications **VIS-4**, **VIS-5**, **VIS-6**, and **VIS-7**.

Zone District Requirements

No general visual requirements are identified.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff has summarized key points received from agency and public correspondence on the BEP II project docketed with the Energy Commission. The following listings of comments (below) were determined relevant for response under the **VISUAL RESOURCES** section. Correspondence on the Preliminary Staff Assessment (November 2003) was received from the City of Blythe in a letter dated July 16, 2004; and Caithness Blythe II, LLC in a letter dated April 2004. The correspondent's summarized comments have been listed with staff's response provided in italics below it.

CITY OF BLYTHE

Comment #11 – The City states "Exterior colors for each building and all related infra- or superstructure must be accurately presented on a color rendering (or renderings) and must be approved by the City of Blythe. Such approvals should be obtained prior to the ordering of any materials for the project that would be affected by this requirement."

> Response – *Staff concurs with the City. Staff has revised the original PSA condition of certification. See Condition of Certification **VIS-4** in the Final Staff Assessment (FSA).*

Comment #12 – The City states "Lighting for the plant shall not shine onto other properties or onto the adjacent public rights-of-way. In addition, all on site exterior lighting shall conform to generally accepted practices of preventing light pollution and impacting the night skyline by providing appropriate shielding and down casting of lighting while providing appropriate shielding and down casting of lighting while providing the required exit path illumination."

Response - *Staff concurs with the City. Staff has revised the original PSA conditions of certification. See Condition of Certification **VIS-2** and **VIS-6** in the FSA.*

Comment #13 – The City states "Any signage to be utilized for this project must be approved by the Development Services Department."

Response - *Staff concurs with the City. Staff has revised the original PSA condition of certification. See Condition of Certification **VIS-7** in the FSA.*

Caithness Blythe II, LLC

Comment #1 – The applicant states "Visual Resources Table 1 and the text provided with the table have several incorrect dimensions for plant components."

Response - *Staff revised Visual Resources Table 1and text in the FSA.*

Comment #2 – The applicant states "The section headed "Switchyard" notes the BEP II generation facilities would be connected directly to the Buck Boulevard Substation and as a result would not require a separate switchyard. A generation T&D collector area north of the generation step up transformers is planned. This area would include breaker positions and takeoff structure. The collector area, called the integration switchyard, is shown on the arrangement drawings that have been provided to the CEC as part of the revised BEP II Project Description."

Response - *Staff revised the "Project Description" portion in the Visual Resources section in the FSA.*

Comment #3 – The applicant states "A 12.4 acre area, central to the 152 acre BEP site is identified to be used for construction laydown and parking. Because of changes made to the BEP evaporation pond arrangement, all of the 12.4 acres identified in figure 2.0-24 of the AFC will not be available for BEP II construction laydown and parking. However, BEP II will use the 9.3 acre area just to the west of the BEP facility previously utilized for BEP construction. . ."

Response - *Staff revised the "Project Description" portion in the Visual Resources section in the FSA.*

Comment #4 – The applicant states "The section headed "Switchyard, Electrical Transmission Interconnection, and Linear Facilities" states BEP II would interconnect on-site with the existing (BEP I) support infrastructure (electric, gas, water, brine return)." We clarify BEP II will have interconnections with existing infrastructure for electric transmission and fuel gas supply. BEP II may interconnect with existing BEP water supply. BEP II may extend a brine line to the BEP evaporation ponds. . ."

Response - *Staff revised the "Project Description" portion in the Visual Resources section in the FSA. This section was deleted.*

Comment #5 – The applicant states "Staff has not accurately described the setting of the BEP project. CB II notes approximately of the existing BEP fenceline along Hobson is landscaped with plants. These plants, when fully grown will extend to a height of approximately 12 feet will mostly block the view of BEP for any traffic along Hobsonway."

> Response - *This analysis has identified the existence of Florida Power and Light's Blythe Energy Project (BEP I). The existing BEP I is approximately 1,300-1,800 feet from the proposed BEP II. BEP I was required to install landscaping on their project site as a condition of their license (VIS-4 Commission Decision Blythe Energy Project, March 2001). BEP I landscaping, at maturity, may be at a height and fullness to provide some screening of the proposed BEP II, and help to decrease the visual cumulative impact of both projects in this scenic valued area.*

Comment #6 – The applicant states "Staff has indicated the overall visual sensitivity for KOP 3 is moderate. Staff concluded however, in its assessment of BEP the viewer sensitivity is low. CB II does not agree with Staff's assessment that there should be a difference between BEP and BEP II from KOP 3."

> *Response - Staff has attempted to clarify the visual information used in this analysis. The change in overall visual sensitivity ranges from low to high. Staff determined the overall visual sensitivity using the existing KOP 3 view (consisting of a flat sparely vegetated tan-colored desert having several transmission lines and an existing power plant [BEP I]) without the existence of the BEP II composed a moderate overall viewer visual sensitivity assessment (see page 4.12-9). Staff concluded the level of overall visual change to the existing desert view at KOP 3, with a built BEP II, is low and would not result in a significant visual impact with implementation of the conditions of certification (see page 4.12-18).*

Comment #7 – The applicant states "Staff has indicated the overall visual sensitivity for KOP 4 is low to moderate. Staff concluded however, in its assessment of BEP the viewer sensitivity is low. CB II does not agree with Staff's assessment that there should be a difference between BEP and BEP II from KOP 4."

> *Response - Staff determined that the existing KOP 4 view (without the existence of the BEP II) composed a low-to-moderate overall viewer visual sensitivity assessment (page 4.12-10). Staff concluded that there is no overall visual change to the existing KOP 4 view (with BEP II). The anticipated lack of project visibility due to the substantial viewing distance and the screening provided by intervening vegetation would result in no significant visual impact at KOP 4 (page 4.12-18).*

Comment #8 – The applicant states "Staff has indicated the overall visual sensitivity for KOP 5 is moderate to high. Staff concluded however, in its assessment of BEP the viewer sensitivity is low to moderate. CB II does not agree with Staff's assessment that there should be a difference between BEP and BEP II and in fact, BEP II is further from KOP 5 than BEP is, so we do not agree with Staff's assessment."

Response - Staff determined that the existing KOP 5 view composed a moderate-to-high overall viewer visual sensitivity assessment (page 4.12-11). Staff concluded that the level of overall visual change to the existing KOP 5 view would be low and would not result in a significant visual impact (page 4.12-19).

Comment #9 – The applicant states "Staff has indicated the overall visual sensitivity for KOP 7 is moderate. Staff concluded however, in its assessment of BEP the viewer sensitivity is low to moderate. CB II does not agree with Staff's assessment that there should be a difference between BEP and BEP II from KOP 7 even though BEP II is slightly closer to the KOP."

Response - Staff determined that the existing KOP 7 view composed a moderate overall viewer visual sensitivity assessment (page 4.12-13). Staff concluded that the level of overall visual change to the existing KOP 7 view would be moderate-to-high; though adverse, it would generate a less than significant visual impact with implementation of the conditions of certifications (page 4.12-21).

Comment #10 – The applicant states "Staff has indicated that Construction activities will result in short term adverse, but not significant visual impacts. This is the same conclusion Staff reached for BEP construction activities. . .Viewer exposure is not significantly different during the construction activities for either project. There were no complaints regarding the construction of BEP, therefore additional visual impact mitigation as proposed by Staff is unnecessary and unwarranted."

*Response – Revised Condition of Certification **VIS-1** is recommended by staff, in addition to the applicant's proposed mitigation, so that the proposed BEP II would be consistent with the applicable adopted City and County LORS, and the requirements of CEQA.*

Comment #11- The applicant states "Staff should revise the conclusions relative to CEQA to reflect CB II's [*applicant*] comments #5 - #10."

Response - Staff has attempted to clarify the visual information used in the analysis in the responses to the applicant's comments #6 through #9 above.

Comment #12 – The applicant states "The section on "Mitigation of Construction Impacts" proposes "The project owner shall require from its contractors that all facility construction sites and staging, material, and equipment storage area be visually screened from adjacent public roads and nearby residences. We note this proposed mitigation measure does not acknowledge the location of the proposed laydown areas of the recently completed BEP I facility. . . We contend screening of "all facility construction sites" is impractical and not supported by Staff's own finding of insignificant impact. Therefore the mitigation is unwarranted."

*Response - Condition of Certification **VIS-1** is being recommended by staff to supplement the applicant's proposed mitigation so that the proposed project would be consistent with the applicable adopted City and County LORS pertaining to scenic valued resources. In addition the condition is to ensure that*

the project's construction activities would generate a less than significant effect as required by CEQA. Staff concluded that the temporary visual impacts generated by construction activities would be visible from Hobsonway, nearby residences, and I-10.

Comment #13 – The applicant states "Staff has proposed the planting of California Fan Palms and dense foliage native trees along of the western site boundary, along Hobsonway and also along of Buck Blvd. CB II does not believe Staff has an accurate view of the existing BEP site nor the existing landscaping requirements. CB II notes 1.) Landscaping must be approved by the City of Blythe – CEC's proposed landscaping method would not be acceptable to the City, 2.) USFWS [*United States Fish and Wildlife Service*] will need to issue either a Biological Opinion or a consistency determination – USFWS will not approve the Staff suggestions for landscaping and 3.) CB II has indicated there are no plans to perform any work outside the project fenceline."

Response - *Staff has revised the original PSA condition of certification. See Condition of Certification **VIS-5** in the FSA. Condition of Certification **VIS-5** is being recommended by staff to supplement the applicant's proposed mitigation so that the proposed project would be consistent with the applicable adopted City and County LORS, and generate a less than significant effect as required by CEQA.*

CONCLUSIONS

Energy Commission staff analyzed both the potential visual impacts of the proposed BEP II and the compliance of the project with applicable laws, ordinances, regulations, and standards.

Staff concludes that the project, as proposed, has the potential to cause adverse and significant visual impacts. However, with effective implementation of the proposed conditions of certification for surface treatment, landscaping and lighting control, the project's visual impacts would be less than significant.

Staff has also concluded that the project's contribution to cumulative visual and lighting impacts would not be cumulatively considerable, based on effective implementation of the conditions of certification.

The proposed project would not cause significant visual impacts on a minority population; there would be no environmental justice issues pertaining to visual resources.

The Energy Commission should adopt the following conditions of certification if it approves the project.

PROPOSED CONDITIONS OF CERTIFICATION

The purposed Visual Resources Conditions of Certification in this Final Staff Assessment differ from those drafted in the Preliminary Staff Assessment dated November 2003. These differences resulted from new information regarding the project and new standards developed by Energy Commission technical staff and the Compliance Project Manager for easier implementation of the Conditions.

CONSTRUCTION SCREENING

VIS-1 The project owner shall reduce the visibility of construction equipment, materials, and activities at the project site and as appropriate at any staging and material and equipment storage areas with temporary screening such as fabric attached to fencing or berms prior to the start of ground disturbance. Screening shall be of an appropriate height, design, opacity, and color for each specific location, as determined by the Compliance Project Manager (CPM).

The project owner shall submit to the CPM for review and approval a specific screening plan whose proper implementation will satisfy these requirements. The project owner shall provide a sample (at least 3" x 5") of the proposed screening material with the plan.

Verification: At least 30 days prior to the start of site mobilization, the project owner shall submit the screening plan to the CPM for review and approval. The screening shall be installed during the site mobilization phase. The project owner shall notify the CPM when installation is completed.

The project owner shall provide the CPM with electronic color photographs after installing screening at the power plant site and at staging and material and equipment storage areas showing the effectiveness of the screening.

Construction Lighting

VIS-2 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 and security;

b) All fixed position lighting shall be shielded/hooded, and directed downward and toward the area to be illuminated to prevent direct illumination of the night sky and direct light trespass (direct light extending outside the boundaries of the power plant site or the site of construction of ancillary facilities, including any security related boundaries); and

c) Wherever feasible and safe and not needed for security, lighting shall be kept off when not in use.

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 requires modifications to the lighting, 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.

Within 48 hours of receiving a lighting complaint, the project owner shall provide the CPM with a complaint resolution form report as specified in the General Conditions section, including a proposal to resolve the complaint and a schedule for implementation. The project owner shall notify the CPM within 48 hours after completing implementation of the proposed resolution. A copy of the complaint resolution form report shall be included in the subsequent Monthly Compliance Report.

Site Surface Restoration

VIS-3 The project owner shall remove all evidence of the temporary construction activities and shall restore the ground surface to the original or better condition, including the replacement of any vegetation or paving removed during construction where project development does not preclude this activity. The project owner shall submit to the CPM for review and approval a surface restoration plan, the proper implementation of which will satisfy these requirements.

Verification: At least 60 days prior to the start of commercial operation, the project owner shall submit the surface restoration plan to the CPM for review and approval.

If the CPM notifies the project owner that any revisions of the surface restoration plan are needed, the project owner shall submit to the CPM a plan with the specified revisions within 30 days of receiving that notification.

The project owner shall complete surface restoration within 60 days after the start of commercial operation. The project owner shall notify the CPM within seven days after completion of surface restoration that the restoration is ready for inspection.

Surface Treatment of Project Structures and Buildings

VIS-4 The project owner shall treat the surfaces of all project structures and buildings visible to the public such that a) their color(s) minimize(s) visual intrusion and contrast by blending with the landscape; b) their colors and finishes do not create excessive glare; and c) their colors and finishes are consistent with local policies and ordinances. The transmission line conductors shall be non-specular and non-reflective, and the insulators shall be non-reflective and non-refractive.

The project owner shall submit for CPM review and approval a specific surface treatment plan that will satisfy these requirements. The treatment plan shall include:

a) A description of the overall rationale for the proposed surface treatment, including the selection of the proposed color(s) and finishes;

b) A list of each major project structure, building, tank, pipe, and wall; the transmission line towers and/or poles; and fencing, specifying the color(s) and finish proposed for each. Colors must be identified by vendor, name, and number; or according to a universal designation system;

c) One set of color brochures or color chips showing each proposed color and finish;

d) One set of 11" x 17" color photo simulations at life size scale, of the treatment proposed for use on project structures, including structures treated during manufacture, from Key Observation Point(s) 2 and 6 (locations shown on Figures 6B and 10B of the Final Staff Assessment);

e) A specific 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 in the field, until the project owner receives notification of approval of the treatment plan by the CPM. Subsequent modifications to the treatment plan are prohibited without CPM approval.

Verification: At least 90 days prior to specifying to the vendor the color(s) and finish(es) of the first structures or buildings that are surface treated during manufacture, the project owner shall submit the proposed treatment plan to the CPM for review and approval and simultaneously to the City of Blythe for review and comment.

If the CPM determines that the plan requires revision, the project owner shall provide to the CPM a plan with the specified revision(s) for review and approval by the CPM before any treatment is applied. Any modifications to the treatment plan must be submitted to the CPM for review and approval.

Prior to the start of commercial operation, the project owner shall notify the CPM that surface treatment of all listed structures and buildings has been completed and they are ready for inspection and shall submit one set of electronic color photographs from the same key observation points identified in (d) above.

The project owner shall provide a status report regarding surface treatment maintenance in the Annual Compliance Report. The report shall specify a): the condition of the surfaces of all structures and buildings at the end of the reporting year; b) maintenance activities that occurred during the reporting year; and c) the schedule of maintenance activities for the next year.

Landscape Screening

VIS-5 The project owner shall provide landscaping that reduces the visibility of the power plant structures and complies with local policies and ordinances. Trees and other vegetation consisting of informal groupings of fast-growing native species shall be strategically placed and of sufficient density and height to effectively screen the power plant structures within the shortest feasible time.

The project owner shall submit to the CPM for review and approval and simultaneously to City of Blythe for review and comment a landscaping plan whose proper implementation will satisfy these requirements. The plan shall include:

a) A detailed landscape, grading, and irrigation plan, at a reasonable scale. The plan shall demonstrate how the requirements stated above shall be met. The plan shall provide a detailed installation schedule demonstrating installation of as much of the landscaping as early in the construction process as is feasible in coordination with project construction.

b) A list (prepared by a qualified professional arborist familiar with local growing conditions) of proposed species, specifying installation sizes, growth rates, expected time to maturity, expected size at five years and at maturity, spacing, number, availability, and a discussion of the suitability of the plants for the site conditions and mitigation objectives, with the objective of providing the widest possible range of species from which to choose;

c) Maintenance procedures, including any needed irrigation and a plan for routine annual or semi-annual debris removal for the life of the project;

d) A procedure for monitoring for and replacement of unsuccessful plantings for the life of the project; and

e) One set of 11”x17” color photo-simulations of the proposed landscaping at five years and twenty years after planting, as viewed from Key Observation Point(s) 2 and 6 (locations shown on Figures 6B and 10B of the Final Staff Assessment).

The plan shall not be implemented until the project owner receives final approval from the CPM.

Verification: The landscaping plan shall be submitted to the CPM for review and approval and simultaneously to the City of Blythe for review and comment at least 90 days prior to installation.

If the CPM determines that the plan requires revision, the project owner shall provide to the CPM and simultaneously to the City of Blythe a revised plan for review and approval by the CPM.

The planting must occur during the first optimal planting season following site mobilization. The project owner shall simultaneously notify the CPM and the City of Blythe within seven days after completing installation of the landscaping, that the landscaping is ready for inspection.

The project owner shall report landscape maintenance activities, including replacement of dead or dying vegetation, for the previous year of operation in each Annual Compliance Report.

Permanent Exterior Lighting

VIS-6 To the extent feasible, consistent with safety and security considerations, the project owner shall design and install all permanent exterior lighting such that a) light fixtures do not cause obtrusive spill light beyond the project site; b) lighting does not cause excessive reflected glare; c) direct lighting does not illuminate the nighttime sky; d) illumination of the project and its immediate

vicinity is minimized, and e) the plan complies with local policies and ordinances.

The project owner shall submit to the CPM for review and approval and simultaneously to the City of Blythe for review and comment a lighting mitigation plan that includes the following:

(1) Location and direction of light fixtures shall take the lighting mitigation requirements into account;

(2) Lighting design shall consider setbacks of project features from the site boundary to aid in satisfying the lighting mitigation requirements;

(3) Lighting shall incorporate fixture hoods/shielding, with light directed downward or toward the area to be illuminated;

(4) Light fixtures shall not cause obtrusive spill light beyond the project boundary.

(5) All lighting shall be of minimum necessary brightness consistent with operational safety and security; and

(6) Lights in high illumination areas not occupied on a continuous basis (such as maintenance platforms) shall have (in addition to hoods) switches, timer switches, or motion detectors so that the lights operate only when the area is occupied.

Verification: At least 90 days prior to ordering any permanent exterior lighting, the project owner shall contact the CPM to discuss the documentation required in the lighting mitigation plan.

At least 60 days prior to ordering any permanent exterior lighting, the project owner shall submit to the CPM for review and approval and simultaneously to the City of Blythe for review and comment a lighting mitigation plan.

If the CPM determines that the plan requires revision, the project owner shall provide to the CPM a revised plan for review and approval by the CPM.

The project owner shall not order any exterior lighting until receiving CPM approval of the lighting mitigation plan.

Prior to commercial operation, the project owner shall notify the CPM that the lighting has been completed and is ready for inspection. If after inspection the CPM notifies the project owner that modifications to the lighting are needed, within 30 days of receiving that notification the project owner shall implement the modifications and notify the CPM that the modifications have been completed and are ready for inspection.

Within 48 hours of receiving a lighting complaint, the project owner shall provide the CPM with a complaint resolution form report as specified in the Compliance General Conditions including a proposal to resolve the complaint, and a schedule for implementation. A copy of the complaint resolution form report shall be submitted to the CPM within 30 days of complaint resolution.

Signage

VIS-7 The project owner shall install minimal signage visible to the public, which shall a) have unobtrusive colors and finishes that prevent excessive glare; and b) be consistent with the policies and ordinances of the City of Blythe. The design of any signs required by safety regulations shall conform to the criteria established by those regulations.

Verification: The project owner shall notify the CPM and the City of Blythe that appropriate signage has been installed and is ready for inspection prior to the start of commercial operation, and shall provide the CPM with electronic color photographs of the signage. If the CPM determines that signage requires changes, the project owner shall complete the changes within 60 days and notify the CPM that the changes have been completed.

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VISUAL RESOURCES - APPENDIX VR-1

Blythe Energy Project Phase II - Visual Resources Staff Assessment - Summary of Analysis

(Does Not Include Plume Analysis)

VIEWPOINT		EXISTING VISUAL SETTING							VISUAL CHANGE					IMPACT SIGNIFICANCE	
Key Observation Point (KOP)	Description	Visual Quality	Viewer Concern	Viewer Exposure				Overall Visual Sensitivity	Description of Visual Change	Visual Contrast	Project Dominance	View Blockage	Overall Visual Change	Mitigation / Conditions	Impact Significance with Mitigation
				Visibility	Number of Viewers	Duration of View	Overall Viewer Exposure								
KOP 1 **EASTBOUND INTERSTATE 10** **Figures 5A / 5B**	View to the northeast from eastbound I-10, approximately 0.3 mi. southwest of the project site.	**Low to Moderate** Foreground to middleground level, desert mesa landscape lacking distinctive features and dominated by energy generation and transmission infrastructure and I-10. The immediate landscape lacks scenic features or elements of visual interest. Portions of background mountains are blocked by the industrial forms of the existing BEP I.	**Low to Moderate** Travelers on I-10 anticipate a foreground to middleground desert landscape dominated by energy infrastructure with a prominent presence of the rectangular block forms of trucks and containers on I-10. An increase in industrial character or view blockage would be seen as an adverse visual change.	**High**	**High**	**Moderate**	**Moderate to High**	**Moderate**	Addition of noticeable geometric forms with horizontal to vertical lines and complex industrial character. Facilities would be visible and co-dominant at this foreground viewing distance.	**Low to Moderate**	**Co-Dominant**	**Low to Moderate**	**Low to Moderate**	**Applicant and Staff Measures & Staff's Conditions: VIS-4 VIS-5**	**Adverse Less than Significant**
KOP 2 **EASTBOUND HOBSONWAY** **Figures 6A / 6B**	View to the east-northeast from eastbound Hobsonway, approximately 0.4 mi. west of the project site.	**Low to Moderate** Foreground to middleground level, desert mesa landscape lacking distinctive features and dominated by energy generation and transmission infrastructure and Hobsonway. The immediate landscape lacks scenic features or elements of visual interest. Portions of background mountains are blocked by the industrial forms of the existing BEP I and transmission infrastructure.	**Low to Moderate** Travelers on this stretch of Hobsonway anticipate a foreground to middleground non-descript desert landscape with prominent energy infrastructure. However, any increase in industrial character would be seen as an adverse visual change.	**High**	**Low**	Extended	**Moderate to High**	**Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass and scale would be greater than existing BEP I structures.	**Moderate to High**	**Dominant**	**Moderate**	**Moderate to High**	**Applicant and Staff Measures & Staff's Conditions: VIS-4 VIS-5**	**Adverse Less than Significant**
KOP 3 **MESA VERDE (Nicholls Warm Springs)** **Figures 7A / 7B**	View to the northeast from the north side of the Mesa Verde residential subdivision, approximately 2.5 mi. southwest of the project site.	**Low to Moderate** Foreground to middleground level, monotone desert mesa landscape, lacking distinctive features or elements of visual interest. Prominent energy and transportation infrastructure.	**Moderate** Although residences are generally attributed a higher degree of viewer sensitivity, in this case, viewer expectations are tempered by the visibility of the intervening I-10 corridor and electric transmission lines, and the visibility of the existing BEP I and facilities associated with Blythe Municipal Airport.	**Low**	**Low to Moderate**	**Extended**	**Moderate**	**Moderate**	Addition of minimally noticeable geometric forms. Structural mass would be similar to BEP I. Facilities would be visible but subordinate at this background viewing distance.	**Low**	**Subordinate**	**Low**	**Low**	**Applicant and Staff Measures & Staff's Conditions: VIS-4 VIS-5**	**Not Significant**
KOP 4 **CENTRAL BLYTHE** **Figures 8A / 8B**	View to the west "C" Canal Levee at Hobsonway, approximately 4 mi. east of the project site near central Blythe.	**Low to Moderate** Foreground to middleground level, agricultural landscape consisting of fields, roads, and utility infrastructure. Generally lacking distinctive features or elements of visual interest.	**Low** Viewers near this location would be accessing commercial facilities at the adjacent commercial center. Viewer expectations would include the transitional landscape between urban and rural settings that include various forms of infrastructure as well as agricultural and commercial uses.	**Low**	**Moderate to High**	**Brief to Moderate**	**Moderate**	**Low to Moderate**	No visible change.	**None**	**None**	**None**	**None**	**None**	**None**
KOP 5 **BLYTHE MUNICIPAL GOLF COURSE & RESIDENCES** **Figures 9A / 9B**	View to the southwest from Blythe Municipal Golf Course, approximately 4.5 mile northwest of the project site.	**Moderate to High** Panoramic vista views overlooking the Palo Verde Valley and Palo Verde Mesa backdropped by distant mountains. Elevated perspective provides visual access to a regional landscape that offers more distinctive features with greater visual variety and interest.	**Moderate to High** Residents in the Mesa Bluffs area are situated along the edge of the bluff to take advantage of the vista views of a predominantly agricultural and naturally appearing landscape with few structural features.	**Low**	**Moderate**	**Extended**	**Moderate**	**Moderate to High**	Addition of minimally noticeable geometric forms. Structural characteristics and mass would be similar to BEP I facilities and would appear subordinate at this background viewing distance.	**Low**	**Subordinate**	**Low**	**Low**	**None**	**Not Significant**
KOP 6 **WESTBOUND HOBSONWAY** **Figures 10A / 10B**	View to the northwest from westbound Hobsonway, at the intersection of Hobsonway and Buck Boulevard.	**Low to Moderate** Foreground level, highly modified desert mesa dominated by energy generation and transmission infrastructure. The immediate landscape lacks scenic features or elements of visual interest. Portions of background mountains are blocked by the industrial forms of the existing BEP I.	**Low to Moderate** Travelers along Hobsonway generally anticipate open, minimally obstruc ted views though viewer expectations will now be conditioned by the prominent industrial presence of the BEP I. A noticeable increase in visible industrial or additional view blockage would be perceived as an adverse visual change.	**High**	**Low**	**Moderate to Extended**	**Moderate**	**Low to Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass and scale would appear greater than the existing facilities due to the close proximity of BEP II to Hobsonway.	**Moderate to High**	**Co-dominant to Dominant**	**Moderate**	**Moderate to High**	**Applicant and Staff Measures & Staff's Conditions: VIS-4 VIS-5**	**Adverse Less than Significant**
KOP 7 **WESTBOUND INTERSTATE 10** **Figure 11**	View to the northwest from westbound Interstate 10, approximately 0.4 mile southeast of the project site.	**Low to Moderate** Foreground level, desert mesa with prominent energy generation and transmission infrastructure. The immediate landscape lacks scenic features or elements of visual interest. Small portions of the background mountains are blocked by the industrial forms of the existing BEP I.	**Low to Moderate** Travelers along I-10 generally anticipate open, minimally obstructed views though viewer expectations will now be conditioned by the prominent industrial presence of the BEP I. A noticeable increase in visible industrial or additional view blockage would be perceived as an adverse visual change.	**High**	**High**	**Moderate**	**Moderate to High**	**Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass and scale would appear greater than the existing facilities due to the closer proximity of BEP II to I-10.	**Moderate to High**	**Co-dominant to Dominant**	**Moderate**	**Moderate to High**	**Applicant and Staff Measures & Staff's Conditions: VIS-4 VIS-5**	**Adverse Less than Significant**

SOURCE: CEC Staff

VISUAL RESOURCES APPENDIX VR-2: STAFF'S VISUAL RESOURCES EVALUATION METHODOLOGY

Staff's analysis of potential impacts to Visual Resources caused by construction or operation of any power plant or related facility largely involves answering the four questions found in Appendix G of the CEQA Guidelines, under Aesthetics. The four questions that must be addressed regarding whether the potential impacts of a project are significant are:

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?

The visual analysis typically distinguishes between three different impact durations: temporary impacts, typically lasting no longer than two years; short-term impacts, generally last no longer than five years; and long-term impacts, which are impacts with a duration greater than five years. In general, short-term impacts are not considered significant.

In addition to visiting the project area for personal observation of how and whether a particular view is experienced, staff also searches for other evidence to determine if the local community values a particular view that might be affected by the project. This includes searching the applicable planning documents covering the area produced by local governments and community groups, as well as searches for any other type of evidence showing whether valued scenic vistas exist within the project's viewshed. Staff relies primarily on personal observation of the project site to make initial determinations of visual character or quality of the area, in comparison with all other landscapes in California, but also gives due deference to official statements by elected governmental bodies concerning the value of visual resources within the project area.

Staff answers each of the four checklist questions for each part of the project both during construction and during operation, including any related facility such as a transmission line or gas pipeline. To answer the first checklist question (Would the project have a substantial adverse effect on a scenic vista?), staff must determine if any such scenic vista exists within the viewshed of the various aspects of the project, and then determine if the project would have a substantial adverse effect on that vista.

To help make these determinations, visual resource professionals often answer a series of questions developed to help focus the analysis, and examine various ways that the project could create an impact to scenic vistas. The Energy Commission's Visual Resources staff has developed such a list for each of the four CEQA guideline questions, drawing upon published methodologies and academic resources (Smardon, et al.), as well as on past experience with other power plant siting cases. Questions

developed to help determine whether the project would significantly affect a scenic vista include:

1. Is the project located in the scenic view of a local/state/federal-designated scenic vista?
2. Is there compelling evidence to show that the view is designated/valued by the local community?
3. Will the project eliminate or block views of valuable visual resources?
4. Would the project create a water vapor plume that could have an adverse effect on a state/federal/local-designated scenic vista?

To help answer the second CEQA checklist question above (Would the project substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?), staff developed the following questions:

1. Is the project located in the scenic view from a local/state/federal-designated scenic highway?
2. Does the project site or its immediate vicinity contain scenic resources, such as trees, rock outcroppings, or historic structures that could be damaged by the project?
3. Would the project create a water vapor plume that could have an adverse effect on the view from a local/state/federal-designated scenic highway?

To answer the third question (Would the project substantially degrade the existing visual character or quality of the site and its surroundings?), staff assesses the existing visual character and quality of the project area, and then determines how the project would affect the character and quality of the project viewshed. To assess whether the project has the potential to substantially degrade the present visual character or quality, staff uses personal observation and such tools as visual simulations to determine if an impact is significant and mitigation is required to reduce the impact to a less-than-significant level. To make that determination, staff examines many factors, such as: how many viewers can see a particular view and for how long, collectively called “viewer exposure;” and to what degree would the project change the aspects of a given view, such as whether the project’s components would block a particular view.
To help determine how the community rates and values the visual character and quality of a given site, and whether the project would substantially alter the present visual character or quality, staff developed the following questions:

1. How many residential, recreational, and traveling (motorist) viewers would have views of the project?
2. Is the project site properly zoned?
3. Would a conditional use permit and/or height variance have been required from the city/county (if so what conditions would the city/county place on the power plant)?
4. Does the project conform to the clear written declarations of local/state/federal agencies to protect designated visual resources of importance or the valued

aesthetic character of a neighborhood (said declaration must be clear, concise, and uncompromised by conflicting declarations, and be an official action of the governing body (City Council/Board of Supervisors) such as a General Plan element, zoning ordinance, or design guideline)?

5. Will the project substantially alter the existing viewshed, including any changes in natural terrain?
6. Does the project substantially change the existing setting?
7. Has the applicant proposed landscaping?
8. Would the project create a water vapor plume that could have an adverse effect on a KOP view?

The process of answering these questions includes an examination of the present views within the project viewshed in terms of aesthetics – i.e., by examining the various aspects that together define the quality of a view – followed by an assessment of how the various aspects of the aesthetics of the view would be affected by the project, which conversely could be described as an analysis of how well the project area can absorb the various aspects of the project into the landscape.

To answer the fourth CEQA Guidelines checklist question (Would the project create a new source of substantial light or glare that would adversely affect day or nighttime views in the area?), staff analyzes the project's lighting plans to ensure they fit with established norms for low-impact lighting designs, and then answers the following questions to determine if a potential for impact from night-lighting exists:

1. With the Energy Commission's standard condition of certification for lighting control, would light or glare be reduced to acceptable levels?
2. Will the project result in significant amounts of backscatter light into the nighttime sky?

VISUAL RESOURCES APPENDIX VR–3

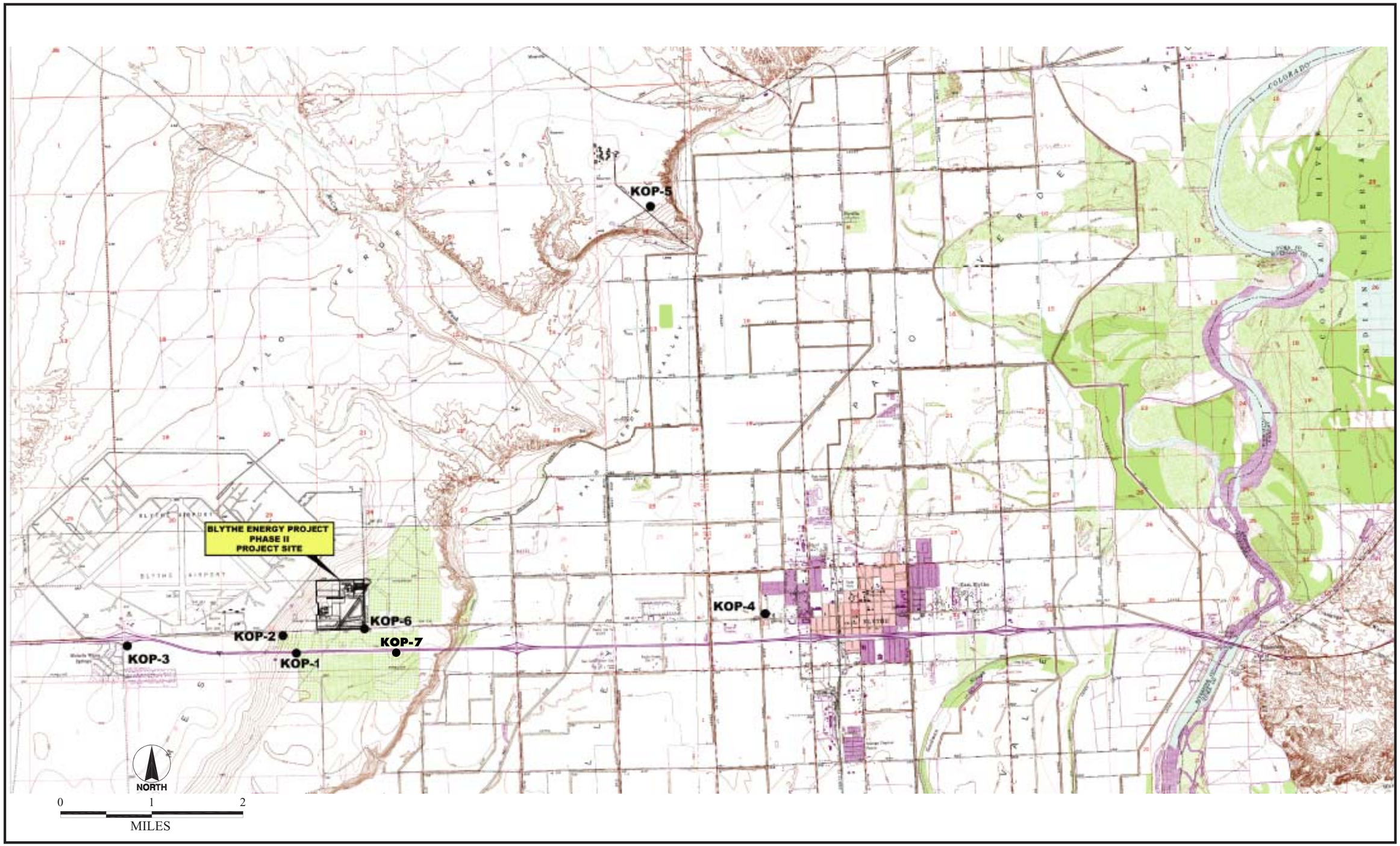
LIGHTING COMPLAINT RESOLUTION FORM

Blythe Energy Project, Phase II City of Blythe, 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.)

VISUAL RESOURCES - FIGURE 1

Blythe Energy Project Phase II - Location of Key Observation Points



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: BEP II 2002a, Figure 7.5-1

VISUAL RESOURCES - FIGURE 2A
Blythe Energy Project Phase II - KOP 1 - Existing View

EXISTING CONDITION

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 2B

Blythe Energy Project Phase II - KOP 1 - Photo Simulation

PHOTO SIMULATION

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 3A
Blythe Energy Project Phase II - KOP 2 - Existing View

EXISTING CONDITION

VISUAL RESOURCES

APRIL 2005

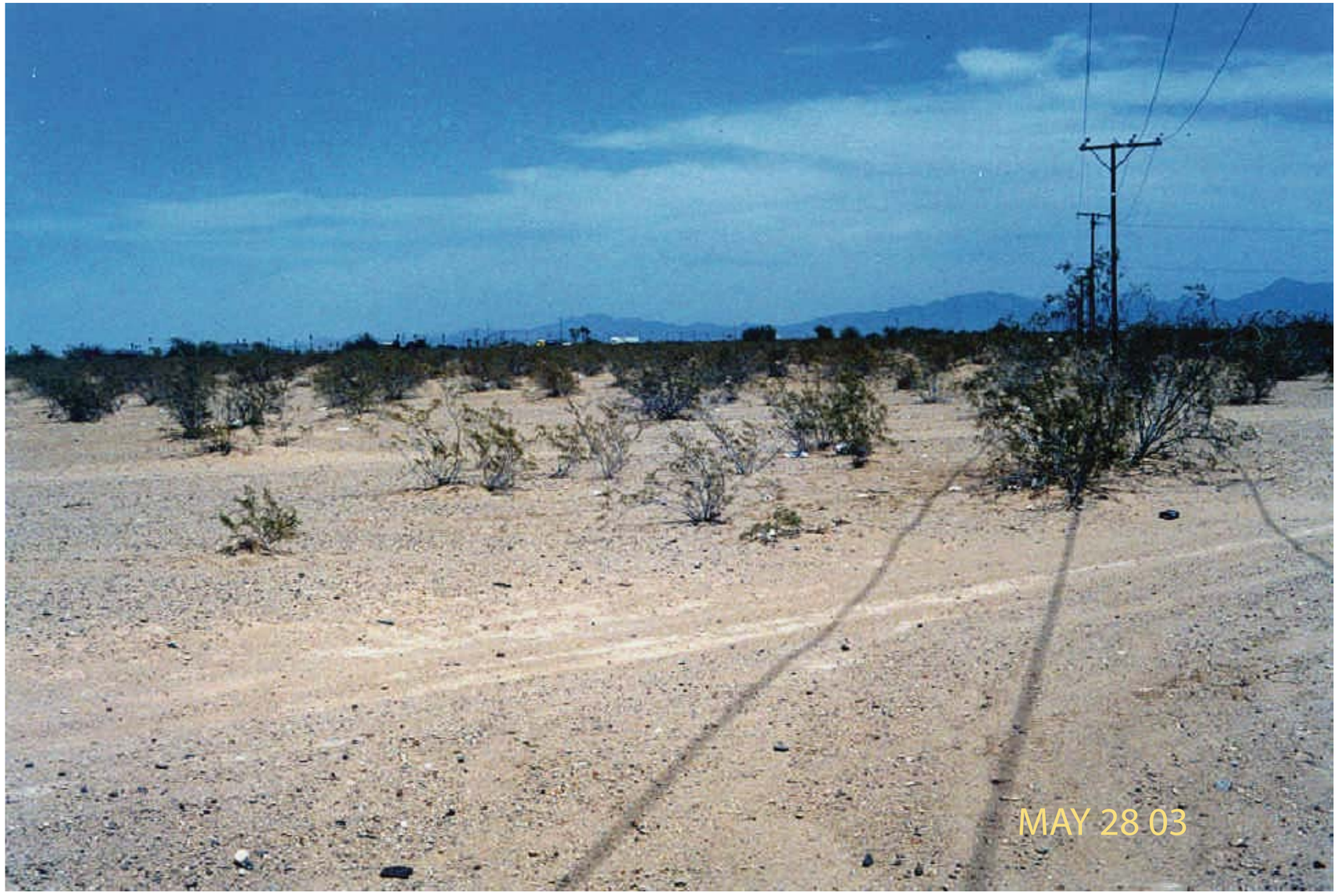
VISUAL RESOURCES - FIGURE 3B
Blythe Energy Project Phase II - KOP 2 - Photo Simulation

PHOTO SIMULATION

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 4A
Blythe Energy Project Phase II - KOP 3 - Existing View



EXISTING CONDITION

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 4B
Blythe Energy Project Phase II - KOP 3 - Photo Simulation

PHOTO SIMULATION

VISUAL RESOURCES - FIGURE 5A
Blythe Energy Project Phase II - KOP 4 - Existing View

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 5B

Blythe Energy Project Phase II - KOP 4 - Photo Simulation

VISUAL RESOURCES - FIGURE 6A
Blythe Energy Project Phase II - KOP 5 - Existing View

EXISTING VIEW

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 6B
Blythe Energy Project Phase II - KOP 5 - Photo Simulation

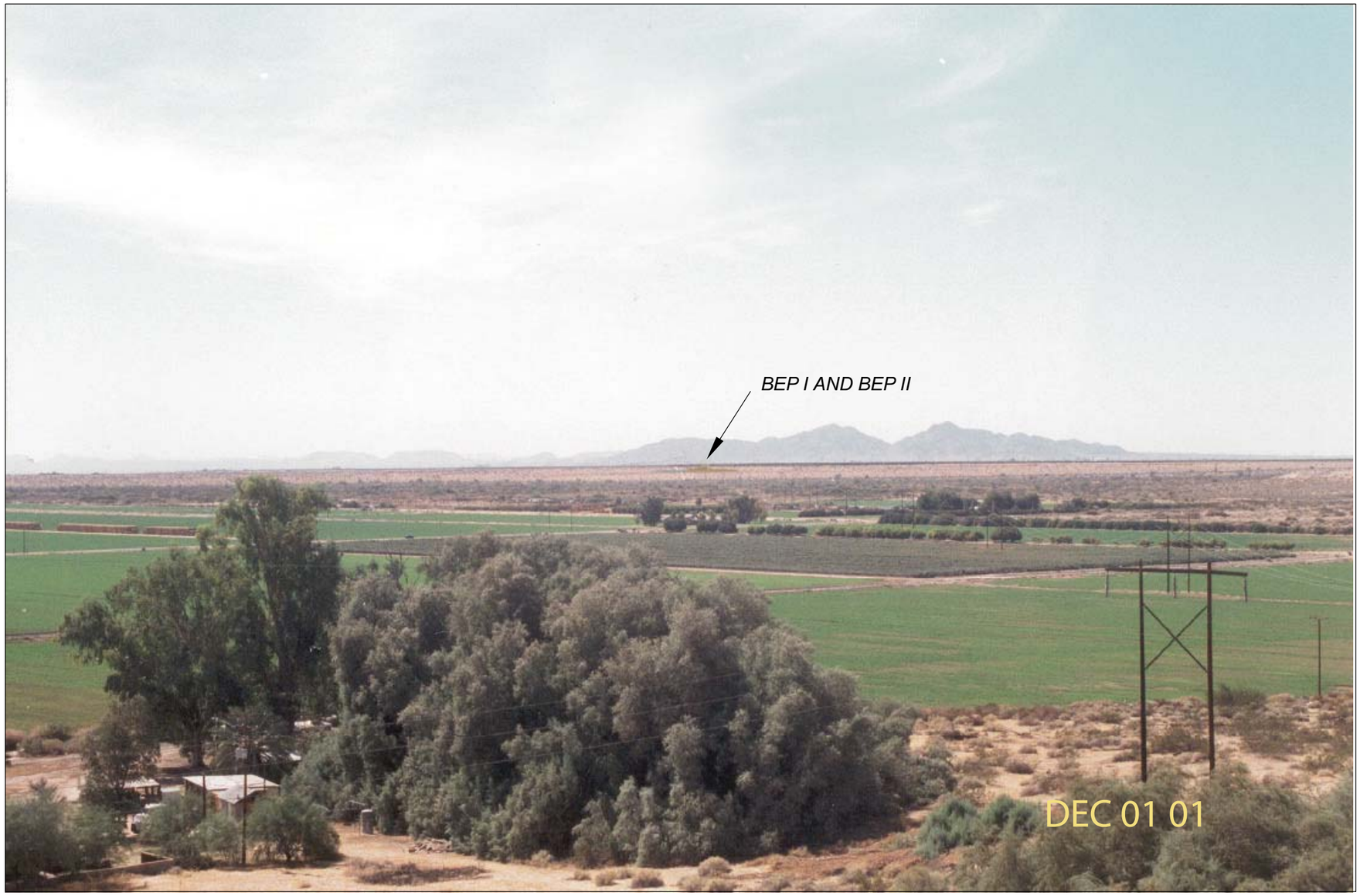
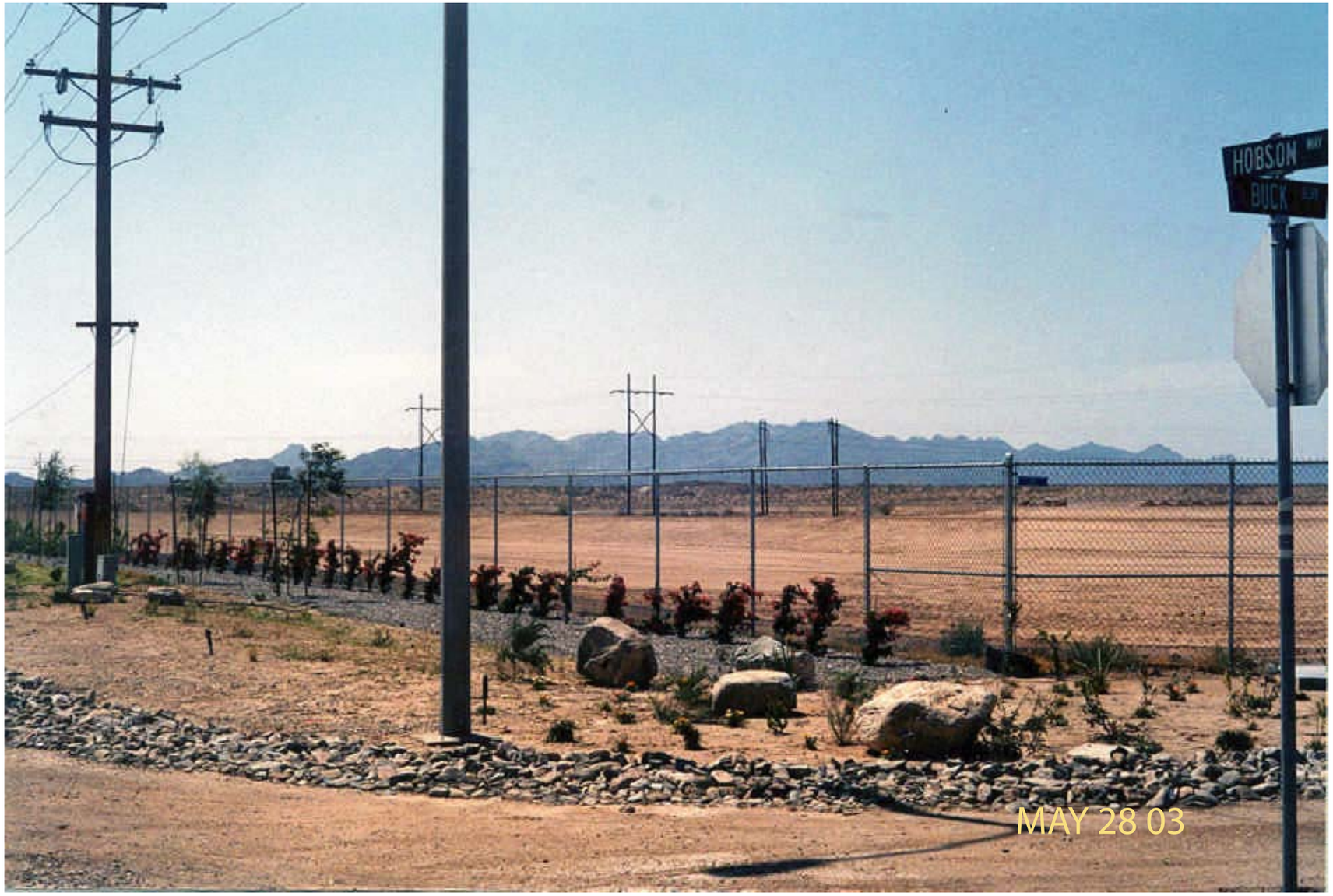


PHOTO SIMULATION

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 7A
Blythe Energy Project Phase II - KOP 6 - Existing View



EXISTING CONDITION

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 7B
Blythe Energy Project Phase II - KOP 6 - Photo Simulation

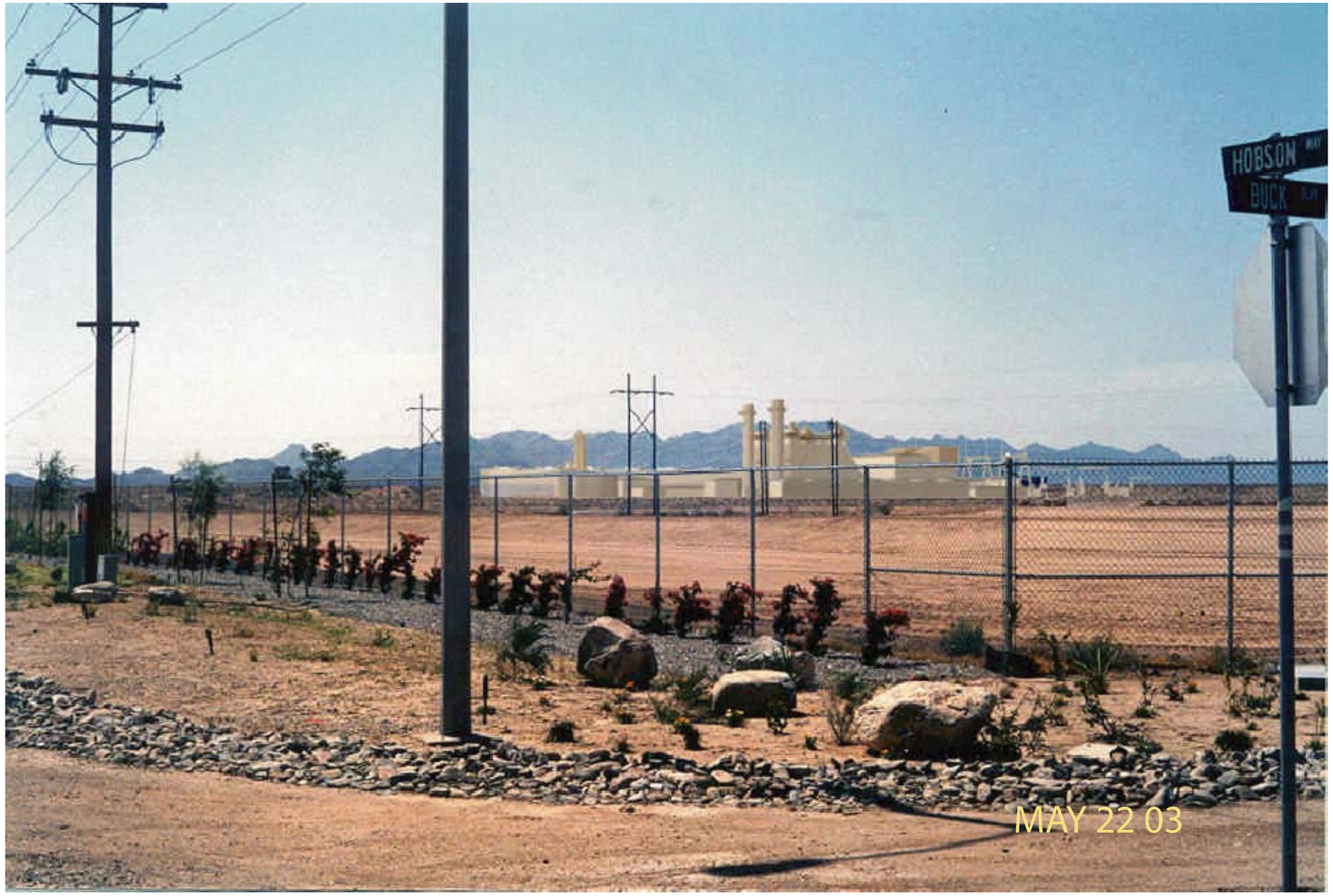


PHOTO SIMULATION

VISUAL RESOURCES

APRIL 2005

VISUAL RESOURCES - FIGURE 8
Blythe Energy Project Phase II - KOP 7 - Existing View

VISUAL RESOURCES APPENDIX VR– 5

VISIBLE PLUME MODELING ANALYSIS

William Walters and Lisa Blewitt

INTRODUCTION

The following provides staff's assessment of the Blythe Energy Project Phase II (BEP II) cooling tower and heat recovery steam generator (HRSG) exhaust stack visible plumes. Staff completed a modeling analysis for the applicant's proposed unabated cooling tower and HRSG designs. The analysis provided in the FSA was revised to use current plume frequency significance criteria.

PROJECT DESCRIPTION

The applicant has proposed a linear 8-cell conventional mechanical-draft cooling towers. The applicant has not proposed to use any methods to abate visible plumes from the cooling towers.

The project includes two separate turbine/heat recovery steam generator systems, each with separate exhaust stacks. The turbines will be equipped with an evaporative inlet cooling system to increase plant output during periods of high ambient temperature conditions. Each HRSG has a duct burner sized to maintain the steam turbine generator maximum output at higher ambient conditions. Duct burner operation is expected to be approximately 2,500 hours per year during peak summer periods (May-September), for approximately 10 hours per day and five days per week. These duct burners will only operate at ambient temperatures of 50°F or greater due to steam turbine steam flow limitations (BEP II 2002b, DR #100). The applicant has not proposed to use any methods to abate visible plumes from the HRSG exhausts.

VISIBLE PLUME MODELING METHODS

PLUME FREQUENCY MODELING

The Combustion Stack Visible Plume (CSVP) model was used to estimate visible plume frequency for the cooling tower and turbine/HRSG exhausts. This model provides conservative estimates of plume frequency by determining the exhaust plume mixing conditions, where if the plume as it mixes with ambient air crosses above the water vapor/air saturation curve a visible plume is assumed to form. This model uses both hourly exhaust parameters and ambient condition data to determine the plume frequency.

CLOUD COVER DATA ANALYSIS METHOD

A plume frequency of 20% of seasonal (November through April) daylight no rain/fog (SDNRNF) high visual contrast (i.e. Clear) hours is used to determine potential plume

impact significance. 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[3] used in the analysis categorizes total sky cover as "clear", "scattered", "broken", "overcast", "partially obscured", and obscured". When the opaque sky cover is less than 50% the ceiling height is given as unlimited, which is represented by the number "722". For the purpose of estimating the high visual contrast hours staff has included in the "Clear" category a) all hours with total sky cover defined as "clear" plus b) half of the non-obscured hours with unlimited ceiling height (i.e. hours with 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 b) for a substantial portion of the time when total sky cover is not clear or obscured the opacity of the sky cover is relatively low (equal to or less than 50%), and these clouds do not substantially reduce contrast with plumes. Staff has estimated that approximately half of the hours with a sky opacity of less than 50% can be considered high visual contrast hours and are included in the "clear" sky definition.

If it is determined that the seasonal (November through April) daylight no rain/fog high visual contrast hour plume frequency is greater than 20% then plume dimensions are determined and a significance analysis of the plumes is included in the Visual Resources section of the Staff Assessment.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

EXISTING CONDITIONS

The applicant verified in Data Response (DR) #93 (BEP II 2002b) that the only other visible water vapor plume source in the vicinity of the project site is the water vapor plume from the Blythe Energy Project Phase I (BEP I) cooling towers. BEP I has a cooling tower as the main cooling system for the steam cycle, which is operated whenever the plant is dispatched. BEP I also has a condenser tower for the inlet chilling system, which is operated whenever the ambient temperature is greater than 50°F. There are also minor steam plumes coming from miscellaneous steam vents, but these dissipate in relatively short distances.

COOLING TOWER DESIGN PARAMETERS

Staff evaluated the applicant's AFC (BEP II 2002a, AFC Sections 7.5.2.2.2 and 7.7.4.3) and Data Response #97 (BEP II 2002b), and performed an independent psychrometric analysis and dispersion modeling analysis. The Combustion Stack Visible Plume (CSVP) model was used to estimate the worst-case potential plume frequency.

[3] This analysis uses TD3280 formatted hourly surface data.

The cooling tower design characteristics, presented below in **Table 1**, were determined through a review of the applicant's AFC and Data Request Responses, and through additional engineering calculations.

Table 1 – New Cooling Tower Operating and Exhaust Parameters

Parameter		New Cooling Tower Design Parameters	
Number of Cells		8 (1 x 8 array)	
Stack Height		12.19 meters (40 feet)	
Cell Stack Diameter		10.07 meters (33 feet)	
Equivalent Stack Diameter		28.48 meters	
Maximum Design Inlet Air Flow Rate (kg/s)		6,068.1 (1)	
Tower Housing Length		144.1 meters (472 feet)	
Tower Housing Width		16.0 meters (52 feet)	
Maximum Heat Rejection Rate (MW)		328.03 (1)	
Design Liquid to Gas (L/G) Mass Ratio		1.26 (1)	
Case # (2)	**Ambient Condition**	**Exhaust Flow Rate (lbs/s/cell)**	**Exhaust Temperature (°F)**
1	95°F, 40% RH with Duct Firing	1570.5	95.8 (3)
2	59°F, 60% RH with Duct Firing	1699.0	80.8 (3)
3	30°F, 60% RH without Duct Firing	1795.1	66.1 (3)

Source: AFC (BEP II 2002a) Table 7.5-1 and Table 7.7-8, and Data Response, Set #1 (BEP II 2002b) DR #97.
Notes:
(1) For applicant modeling review purposes, the SACTI cooling tower design parameters were based on Case 2 (29°F, 60% RH, with Duct Firing).
(2) For CSVP modeling, values were extrapolated or interpolated between data points as necessary.
(3) Staff found, after performing a heat balance, that the exhaust temperatures provided by the applicant appeared to be in error. The exhaust temperature provided by the applicant for Case 1 appears to be too high and the temperatures provided for Cases 2 and 3 were too low. Staff's corrected estimates appear in the table.

For CSVP modeling, 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 the three cases presented in **Table 1**. The exhaust moisture content was determined by assuming saturated conditions at the calculated exhaust temperature.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

Staff modeled the cooling tower plume frequency using the Combustion Stack Visible Plume (CSVP) model. **Table 2** provides the CSVP model visible plume frequency results using a three-year (1989-1991) meteorological data set, obtained from the National Climatic Data Center, from Blythe Airport.

Table 2 – Staff Predicted Hours with Cooling Tower Steam Plumes Blythe Airport 1989-1991 Meteorological Data

	Available (hr)	Plume (hr)	Percent
All Hours	26,280	3,793	14.4%
Daylight Hours	13,425	857	6.4%
Nighttime Hours	12,855	2,936	22.8%
Daylight No Rain/Fog Hours	13,265	790	6.0%
Seasonal Daylight No Rain/Fog Hours*	5,989	740	12.4%
Seasonal Daylight Clear Hours	3,198	342	10.7%

*Seasonal conditions occur anytime from November through April.

These modeling results indicate that the visible plume formation would mainly occur during the cold weather months, with the majority of plume formation occurring during early morning and nighttime hours. For the proposed cooling tower, the maximum

temperature where a visible plume is predicted is 81°F when the relative humidity is 88%.

For the Limited Duct Firing case, considered a reasonable worst-case for plume formation because it assumes duct firing for all ambient conditions above 50°F, the seasonal daylight clear hour plume frequency was determined to be 10.7%. This is below the 20% threshold that would trigger a plume dimension modeling analysis and a visual impact analysis in the Visual Resources section of the Staff Assessment.

APPLICANT PLUME MODELING ANALYSIS

Staff reviewed the applicant's dispersion modeling analysis to predict the frequency and dimensions of visible plumes from the project's proposed unabated cooling tower using the SACTI model. Many of the input parameters used by the applicant do not appear to be correct per the guidelines provided in the SACTI User's Manual (Argonne National Lab., April 1984). Due to these apparent inconsistencies, the Applicant's SACTI results are not presented as part of this analysis.

HRSG VISIBLE PLUME MODELING ANALYSIS

Staff evaluated the applicant's AFC (BEP II 2002a, AFC Sections 7.5.2.2.2 and 7.7.4.3) and Data Response #99 (BEP II 2002b) and performed an independent psychrometric analysis and dispersion modeling analysis. The Combustion Stack Visible Plume (CSVP) model was used to estimate the worst-case potential plume frequency.

HRSG DESIGN PARAMETERS

Based on the 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 3**.

Table 3 – HRSG Exhaust Parameters

Parameter	**HRSG Exhaust Parameters**					
Stack Height	39.62 meters (130 feet)					
Stack Diameter	5.64 meters (18.5 feet)					
	Case 1		**Case 2**		**Case 3**	
Ambient Temp	20°F		59°F		95°F	
Ambient Relative Humidity	60%		60%		60%	
Duct Burner Status	On	Off	On	Off	On	Off
Exhaust Temperature	---	200°F	200°F	200°F	200°F	200°F
Exit Velocity	Calculated for each hour modeled					
Exhaust mass flow rate, lb/hr		3,768,897	3,562,120	3,557,661	3,298,242	3,293,783
Exhaust Molecular Weight	28.35 lbs/lb-mol (with duct firing) and 28.4 lbs/lb-mol (no duct firing)					
Moisture Content (% by vol.)	---	7.69%	8.40%	7.99%	9.78%	9.34%

Source: AFC (BEP II 2002a) Table 7.7-8, Appendix 7.7-A "Emission Calculation Spreadsheets", and Data Response, Set #1 (BEP II 2002b), DR #99.
Notes:
(1) For CSVP modeling, values were extrapolated or interpolated between data points as necessary.

HRSG VISIBLE PLUME MODELING ANALYSIS

Staff modeled the HRSG plumes using the CSVP model with a three-year meteorological data set, obtained from the National Climatic Data Center, for Blythe

Airport. **Table 4** provides the CSVP model visible plume frequency results for each HRSG operating without duct firing.

Table 4 – Staff Predicted Hours with HRSG Steam Plumes Blythe Airport 1989-1991 Meteorological Data

HRSG - No Duct Firing	Available (hr)	Plume (hr)	Percent
All Hours	26,280	58	0.22%
Daylight Hours	13,425	3	0.02%
Nighttime Hours	12,855	55	0.43%
Daylight No Rain/Fog Hours	13,265	3	0.02%
Seasonal Daylight No Rain/Fog Hours*	5,989	3	0.05%
Seasonal Daylight Clear Hours	3,198	2	0.06%

*Seasonal conditions occur anytime from November through April.

Per the applicant's discussion regarding the operating assumptions for the HRSGs, the duct burners will not be operational at ambient temperatures less than 50°F due to steam turbine flow limitations (BEP II 2002b, DR #100). For the proposed HRSGs operating with duct firing at temperatures of 50°F or greater, no visible steam plumes were predicted to occur.

The results provided in **Table 5** confirm that the visible plume formation would mainly occur during the cold weather months, with the majority of plume formation occurring during early morning and nighttime hours. For the proposed HRSG operating without duct firing, the maximum temperature where a visible plume is predicted is 42°F when the relative humidity is 100%.

A plume frequency of 20% of seasonal (November through April) daylight clear is used as an initial plume impact study threshold trigger. The CSVP model predicts plume frequencies significantly less than 20% of seasonal clear hours, which does not trigger additional study of the visual impacts of the plumes from the HRSGs.

CONCLUSIONS

Visible plumes from the proposed BEP II cooling tower and turbine/HRSGs exhausts are expected to occur less than 20% of seasonal daylight clear hours. Therefore, no additional analysis of the project's cooling tower and turbine/HRSG plumes is required.

REFERENCES

BEP II (Caithness Blythe II, LLC) 2002a. Application for Certification, Volumes 1 and 2 (02-AFC-1). Submitted to the California Energy Commission on February 19, 2002.

BEP II (Caithness Blythe II, LLC) 2002b. Data Response, Set #1. Submitted to the California Energy Commission. Docketed on September 30, 2002.

WASTE MANAGEMENT

Testimony of Ramesh Sundareswaran

INTRODUCTION

The purpose of this analysis is to assess the potential impacts associated with the planning and managing of wastes generated from constructing and operating the proposed Blythe Energy Project Phase II (BEP II). It evaluates the proposed waste management plans and mitigation measures designed to reduce the risks and environmental impacts associated with handling, storing, and disposing of project-related hazardous and nonhazardous wastes. The technical scope of this analysis encompasses wastes generated during facility construction and operation, except project wastewaters, such as those discharged to evaporation ponds. Wastewater management is discussed in the **Soil and Water Resources** section of this document.

Energy Commission staff's objective in its waste management analysis is to ensure that the management of the wastes will be in compliance with all applicable laws, ordinances, regulations, and standards (LORS). Compliance with LORS ensures that wastes generated during constructing and operating the proposed project will be managed in an environmentally safe manner; and disposal of project wastes will not result in significant adverse impacts to existing waste disposal facilities.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

A framework, based on environmental laws, ordinances, regulations and standards (LORS) exists to reduce detrimental risks to the public and environment from the generation, storage and disposal of both hazardous and nonhazardous wastes. The institutional and legal conditions of several laws, regulations, policies and programs that would regulate wastes from BEP II are outlined below.

FEDERAL

Resource Conservation and Recovery Act (42 U.S.C. § 6922)

The Resource Conservation and Recovery Act (RCRA) establishes requirements for the management of hazardous wastes from the time of generation to the point of ultimate treatment or disposal. RCRA requires generators of hazardous waste to comply with requirements regarding record keeping practices which identify quantities of hazardous wastes generated and their disposition, labeling practices and use of appropriate containers, use of a manifest system for transportation, and submission of periodic reports to the U.S. Environmental Protection Agency (U.S. EPA) or authorized state.

Title 40, Code of Federal Regulations, part 260

These sections contain regulations promulgated by the U.S. EPA to implement the requirements of RCRA as described above. Characteristics of hazardous waste are described in terms of ignitability, corrosivity, reactivity, and toxicity, and specific types of wastes are listed.

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 (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 criteria and guidelines for the identification of such wastes. It also requires hazardous waste generators to file 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 set forth minimum standards for solid waste handling and disposal, guidelines to ensure conformance of solid waste facilities with county solid waste management plans, as well as enforcement and administration provisions.

Title 22, California Code of Regulations, §66262.10 et seq. (Generator Standards)

These sections establish requirements for generators of hazardous waste. Under these sections, waste generators must determine if their wastes are hazardous according to either specified characteristics or lists of wastes. As in the federal program, hazardous waste generators must obtain federal or state EPA identification numbers, prepare manifests before transporting the waste off-site, and use only permitted treatment, storage, and disposal facilities. Additionally, hazardous waste must only be handled by registered hazardous waste transporters. Generator requirements for record keeping, reporting, packaging, and labeling are also established.

SETTING

PROJECT AND SITE DESCRIPTION

The proposed project is a nominal 520 megawatt natural gas fired combined cycle generating facility consisting of two gas turbine generators with associated heat recovery steam generators and one steam turbine generator (BEP II 2002d). The proposed location is on predominantly unimproved desert land, about five miles west of the city of Blythe. The site was annexed by Blythe in 2000.

A Phase I Environmental Site Assessment (ESA) was performed by Greystone Environmental Consultants in June 2001 to document actual or potential environmental concerns at the BEP II site based on past and present uses of the site (BEP II 2002d). It was performed in accordance with the guidelines of the American Society for Testing and Materials standard 1527 for Phase I ESAs. The Phase I ESA involved gathering information from historical records, aerial photographs, government and other sources, and a physical tour of the site with recordation of visual, olfactory and tactile

perceptions. It was also supplemented with some limited soil sampling due to concerns regarding possible contamination in an area located on the northern boundary of the site. The Phase I ESA concluded the following:

- There is no evidence of any existing, past or threatened releases of contamination in connection with surrounding offsite properties that can impact the site.
- There is a former World War II era landfill located along the northern boundary of the site. Soil sampling along the northern boundary indicated an elevated level of lead at 570 parts per million (ppm) at one sampling location.

The concentration, however, is well below the U.S. Environmental Protection Agency (U.S. EPA) Region IX, Preliminary Remediation Goal (PRG) of 750 ppm for lead in soil permitted for industrial use (U.S. EPA 2002). PRGs are chemical concentrations that correspond to fixed levels of health risk in soil, water, and air and serve as tools that can be used for evaluating and cleaning up contaminated sites. No additional sampling or remediation is therefore warranted at the site, as no adverse health effects are associated with the presence of lead.

IMPACTS

PROJECT SPECIFIC IMPACTS

Construction

Site preparation, along with construction of the generating plant and associated facilities, will generate a variety of nonhazardous and hazardous wastes.

Nonhazardous waste streams from construction may include packing paper, cardboard, wood, glass, and plastics. These will be generated from packing materials, waste construction lumber, insulation materials, and empty containers. BEP II estimates that about 90 tons of these wastes will be generated during construction (BEP II 2002d). These wastes will be recycled where practical, with the rest discharged to the Blythe Sanitary Landfill (BEP II 2002d). Hazardous material containers may be classified as nonhazardous if they are emptied and managed according to specified methods (Cal. Code Regs., tit. 22, §66261.7).

An estimated 50 tons of waste asphalt or concrete will be generated during construction of foundations, parking lots, and roads (BEP II 2002d). Uncontaminated soil and concrete may be used for fill material either on or offsite, with the remainder being disposed of in the Blythe Sanitary Landfill.

Up to 25 tons of metal wastes from welding and cutting operations, packing materials, trim, and empty containers and drums will be generated (BEP II 2002d). This also includes aluminum and copper electrical wiring waste from the power plant, substation, and transmission lines. These wastes will be recycled through scrap metal brokers with the remainder disposed to the Blythe landfill.

Hazardous wastes that may be generated during construction include waste oil and grease, paint, spent solvent, welding materials, and cleanup materials from spills of

hazardous substances. These are typically generated in minor amounts. The construction contractor is considered the actual waste generator and will be responsible for proper hazardous waste handling. Such wastes will be collected in hazardous waste accumulation containers near the point of generation. The containers will be taken to the construction contractor's hazardous waste storage area and within 90 days will be delivered to an authorized hazardous waste management facility (BEP II 2002d).

Although the Phase I ESA did not identify onsite environmental concerns that may not currently be apparent, subsurface contamination could be potentially encountered during earth moving activities. Depending on the nature and extent of contamination present, additional hazardous wastes may require transportation off-site to a permitted facility.

Operation

Under normal operating conditions, the proposed facility will generate both nonhazardous and hazardous wastes.

Nonhazardous wastes generated during plant operation include trash, office wastes, empty containers, broken or used parts, used packing material, and used filters. It is estimated that about 65 cubic yards annually of such wastes will be generated (BEP II 2002d). Metal parts and other materials such as paper, aluminum, and plastic will be recycled through brokers, when possible. Nonrecyclable solid wastes will be transported to the Blythe Sanitary Landfill.

Routine project operation will generate a variety of hazardous wastes. AFC Table 7.11-1 summarizes the hazardous wastes that are anticipated to be routinely generated, along with estimated amounts and planned management methods (BEP II 2002d). Much of the hazardous waste generated is suitable for recycling. Used turbine lubricating oil will be collected for recycling by a licensed waste oil recycler (BEP II 2002d). Every three to four years, air pollution control catalysts must be replaced in order to maintain their control efficiency. Spent catalyst will be returned to the manufacturer for metals reclamation or disposal. Liquid hazardous wastes consisting of solvents containing hazardous levels of heavy metals will be generated during pre-operational and periodic flushing and cleaning of pipes and the heat recovery steam generators (HRSG). A contractor will be used for such cleaning operations and will transport liquid wastes to an offsite facility licensed to manage such wastes.

BEP II has proposed storing process wastewater in an onsite evaporation pond. Such storage will generate residuals with potentially high concentrations of heavy metals and mineral solids, which will then be transported to and managed at an offsite facility. However, the wastewater and evaporation pond have been determined to be deleterious to both avian life and the local aviation system. Zero Liquid Discharge (ZLD) technology has been identified as a viable alternative to the storage of wastewater in the evaporation pond. Discussions about the adverse impacts of the evaporation pond and ZLD's mitigating relief are available in the **Traffic and Transportation** and **Biological Resources** sections of the FSA.

A detailed discussion of the ZLD concept, which allows close to 100 percent reclamation of water, can be found in the **Soils and Water Resources** section of this FSA. Introduction of a ZLD system will generate additional waste streams at BEP II.

Such waste streams will include but not be limited to spent ZLD equipment cleaning material and a recurrent waste that is a highly concentrated sludge, which can be rendered moisture free. These wastes have the potential to exhibit hazardous characteristics. If classified as hazardous, the wastes will need to be appropriately managed in accordance with all federal, state and local hazardous waste requirements. Should the wastes be deemed non-hazardous, it is possible that the wastes, particularly the concentrated sludge, could be characterized as a "California designated waste". This category of waste is either non-hazardous waste that contains pollutants, or hazardous waste which has been granted a variance from hazardous waste management requirements pursuant to Title 22 of the California Code of Regulations. If characterized as non-hazardous waste that contains pollutants, waste could be released in concentrations exceeding applicable water quality objectives (or could reasonably be expected to affect the beneficial uses of the waters of the state) under ambient environmental conditions at a waste management unit (WMU).

Designated wastes can be managed at a Class I or II WMU that typically are landfills, waste piles or land treatment systems. The same wastes can also be disposed of at a Class III WMU (landfills only) if it can be proven that they do not pose a significant threat to underlying ground water quality. Staff proposes condition of certification, **WASTE-7**, in order to ensure proper and adequate classification and management of the ZLD wastes.

IMPACT ON EXISTING WASTE DISPOSAL FACILITIES

The Blythe Sanitary Landfill is a permitted class III (nonhazardous) facility about seven miles north of Blythe. It is projected to remain operational until 2073 and accepts an average daily load of about 50 tons/day. The volume of nonhazardous waste expected from constructing and operating BEP II is expected to be a fraction of one percent of the Blythe landfill's annual capacity. The total remaining capacity of the landfill is estimated to be five million cubic yards. Even discounting the effects of recycling on the total amount of non-hazardous wastes destined for landfilling, the amounts of waste generated during project construction and operation are insignificant relative to existing disposal capacity.

Three Class I landfills in California, at Kettleman Hills in King's County, Buttonwillow in Kern County, and Westmoreland in Imperial County, are permitted to accept hazardous waste. In total, there is in excess of twenty million cubic yards of remaining hazardous waste disposal capacity at these landfills, with remaining operating lifetimes of over 50 years. The amount of hazardous waste transported to these landfills has decreased in recent years due to source reduction efforts by generators, and the transport of waste out of state that is hazardous under California law, but not federal law.

Much of the hazardous waste generated during facility construction and operation will be recycled, such as used oil and spent catalysts. Even without recycling, the generation of hazardous waste from BEP II would be a very small fraction (less than one percent) of existing capacity and will not significantly impact the capacity or remaining life of any of the state's Class I landfills.

CUMULATIVE IMPACTS

Due to the minor amounts of wastes generated during project construction and operation, the insignificant impacts on individual disposal facilities, and the availability of additional regional landfills in Riverside County, cumulative impacts will be insignificant for both hazardous and nonhazardous wastes.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is more than 50 percent within a six-mile radius of the proposed BEP II (please refer to **Socioeconomics Figure 1** in this staff assessment). Staff also reviewed Census 2000 information that shows the low-income population is less than fifty percent within the same radius.

Based on the **Waste Management** analysis, staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project and, therefore, there are no waste-related environmental justice issues related to this project.

FACILITY CLOSURE

During any type of facility closure (see staff's General Conditions section which discusses planned, unexpected temporary, and unexpected permanent closure), one concern is that project wastes not pose any potentially significant problem to the public, workers, or the environment. Staff believes that conditions of certification in the General Conditions section will adequately address waste management issues related to closure.

COMPLIANCE WITH APPLICABLE LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Energy Commission staff concludes that BEP II will be able to comply with all applicable LORS regulating the management of hazardous and non-hazardous wastes during facility construction and operation. The applicant is required to dispose of hazardous and non-hazardous wastes at facilities approved by the Regional Water Quality Control Board or the Cal EPA - Department of Toxic Substances Control. Because hazardous wastes will be produced during project construction and operation, BEP II must acquire and maintain an EPA identification number as a hazardous waste generator as required by Condition of Certification **WASTE-3.** Accordingly, BEP II will be required to properly store, package and label waste, use only approved transporters, prepare hazardous waste manifests, and keep detailed records. Pursuant to title 22, California Code of Regulations, section 67100.1 et seq., a hazardous waste source reduction and management review may be required, depending on the amounts of hazardous waste ultimately generated.

MITIGATION

BEP II intends to implement the following safeguards and measures during construction and operation of the proposed project:

- A hazardous waste reduction program will be developed to minimize the quantity of hazardous wastes generated. Management methods will include source reduction, recycling, treatment, and selection of less toxic materials.
- Nonhazardous wastes will be recycled whenever practical.

Staff has examined the waste management related measures proposed by BEP II and concludes that, together with applicable LORS and the additional conditions proposed by staff, such measures will adequately assure that no significant environmental impacts will result from the management and disposal of project-related waste.

RESPONSE TO AGENCY, PUBLIC AND APPLICANT COMMENTS

No public public comments have been received concerning the project-related impacts discussed in this analysis.

Comments were received from the Western Area Power Administration (WAPA) regarding this analysis. Staff discussed the comments with Ken Mathias of WAPA on 3-14-05. The consensus was that the comments are adequately addressed in the AFC, other FSA sections and through the Applicant's compliance with LORS.

The Applicant made two comments; one concerning the fact that the site has been partially improved and the other suggesting consideration of the use of BEP I Conditions of Certification (COC) for BEP II.

Site improvement: Comment noted and the analysis reflects the fact that the site is partially improved.

Use of BEP I COCs: The COCs cited in the Commission decision for BEP I and those currently proposed for BEP II are are termed "standard" conditions that have been routinely used for various Commission licensing decisions. In terms of basic intent and purpose (i.e., to protect human health and the environment), the BEP I COCs are no different from the COCs proposed for BEP II. However, the BEP II COCs have progressively metamorphosed from COCs similar to those proposed for BEP. As a minimum, (a) changes in laws, regulations, codes, policies and industry practices, (b) feedback obtained at various Commission licensing workshops and hearings, and (c) "evolving lessons and wisdom" learnt during compliance monitoring of Commission licensed projects, mandate that Staff continually revise the standard COCs, as needed. The proposed BEP II COCs are the most recent revisions and are therefore retained for the BEP II project.

CONCLUSIONS AND RECOMMENDATIONS

Management of the wastes generated during construction and operation of BEP II will not result in any significant adverse impacts if the waste management measures and

safeguards proposed in the Application for Certification (02-AFC-1) and the proposed conditions of certification are implemented.

CONDITIONS OF CERTIFICATION

WASTE-1 The project owner shall provide the resume of a California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer, who shall be responsible for oversight of earth moving activities requiring interpretation and proper application of geologic or engineering sciences to the CPM for review and approval. The resume shall show substantial experience in hazardous waste remedial investigation and feasibility studies.

The California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer shall be given full authority by the project owner to oversee and direct 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 California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer or his authorized designee, shall, 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. All reports and proposals must be prepared by or under the direction of a registered professional as referenced above and signed and stamped (must include registration number and expiration date) by that professional.

Depending on the nature and extent of contamination, the California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer 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 California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer, significant remediation may be required, the project owner shall contact representatives of the Colorado River Basin Regional Water Quality Control Board, the Hazardous Materials Management Division of the Riverside County Department of Environmental Health, and the Cypress Regional Office of the California Department of Toxic Substances Control for guidance and possible oversight.

Verification: The project owner shall submit any reports or proposals filed by the California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer 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 or the U.S. Environmental Protection Agency 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 to the CPM 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.

WASTE-6 Prior to any earth moving activities, employees shall receive hazardous-waste-related training that focuses on the recognition of potentially contaminated soil and/or groundwater and contingency procedures to be followed as specified in WASTE-2 above. Training shall comply with

Hazardous Waste Operations (8 CCR 5192) and Hazard Communication (8 CCR 5194) requirements as appropriate.

Verification: The project owner shall notify the CPM via the monthly compliance report of completion of the hazardous waste training program.

WASTE-7 The project owner shall determine if the ZLD generated wastes are hazardous or non-hazardous pursuant to Chapter 12, section 66262.11 of Title 22 of the California Code of Regulations. The wastes shall be managed as designated wastes if the wastes are classified as non-hazardous, unless determined otherwise.

Verification: The project owner shall notify the CPM via the monthly compliance report regarding the classification of the wastes and the treatment/disposal methods utilized consequently.

REFERENCES

BEP II (Blythe Energy Project Phase II) 2002d. Revised Application for Certification for Blythe II. 07/03/2002 (tn: 26100)

U.S. EPA 2002. U.S. Environmental Protection Agency. URL: http/www/epa.gov/region09/waste/sfund/prg/index.html

WORKER SAFETY AND FIRE PROTECTION

Testimony of Alvin J. Greenberg, Ph.D. and Rick Tyler

INTRODUCTION

Worker safety and fire protection is regulated through laws, ordinances, regulations, and standards (LORS), at the federal, State, and local levels. Industrial workers at the facility operate equipment and handle hazardous materials daily and may face hazards that can result in accidents and serious injury. Protection measures are employed to eliminate these hazards or to minimize the risk through special training, protective equipment and procedural controls.

The purpose of this Staff Assessment is to assess the worker safety and fire protection measures proposed by the Blythe Energy Project Phase II (BEP II) and to determine whether the applicant has proposed 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 1970 Congress enacted Public Law 91-596, the Federal Occupational Safety and Health Act of 1970. 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 to 1910.1500 which 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 act represent a compilation of 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 USC § 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 implement the responsibilities assigned by this act.

Applicable Federal requirements include:

- 29 U.S. Code section 651 et seq. (Occupational Safety and Health Act of 1970);
- 29 CFR sections 1910.1 to 1910.1500 (Occupational Safety and Health Administration Safety and Health Regulations);
- 29 CFR sections 1952.170 to 1952.175 (Federal approval of California's plan for enforcement of its own Safety and Health requirements, in lieu of most of the Federal requirements found in 29 CFR §1910.1 to 1910.1500).

STATE

California passed the Occupational Safety and Health Act of 1973 ("Cal/OSHA") as published in the California Labor Code section 6300. Regulations promulgated as a result of the Act are codified at Title 8 of the California Code of Regulations, beginning with sections 337 to 560 and continuing with sections 1514 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)) and thus all Cal/OSHA health and safety standards meet or exceed the federal requirements. Hence, California obtained federal approval of its State health and safety regulations, in lieu of the federal requirements. 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.

The State of California Department of Industrial Relations is charged with responsibility for administering Cal/OSHA. 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 (8 CCR §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 CFR §1910.1200), which established on the federal level an employee's "right to know" about chemical hazards in the workplace, and 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, 8 CCR 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:

- 8 CCR section 339 - List of hazardous chemicals relating to the Hazardous Substance Information and Training Act;
- 8 CCR section 337, et seq. - Cal/OSHA regulations;
- 8 CCR section 3221 – Fire Prevention Plans

- 24 CCR section 3, et seq. - incorporates the current addition of the Uniform Building Code;
- Health and Safety Code section 25500, et seq. - Risk Management Plan requirements for threshold quantity of listed acutely hazardous materials at the facility; and
- Health and Safety Code sections 25500 to 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 California Building Standards Code incorporates current editions of the Uniform Building Code and includes the electrical, mechanical, energy, and fire codes applicable to the project. The City of Blythe Building and Safety department enforces the 2001 edition of the California Building Standards Code.

NFPA standards are incorporated into the California Uniform Fire Code (Cal. Code Regs., tit. 24, part 9). The fire code contains general provisions for fire safety, including: 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.

Similarly, the Uniform Fire Code (UFC) Standards contain 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 California Fire Code, a companion publication to the UFC, incorporates current editions of the UFC standards. The City of Blythe adopted the 2001 edition of the California Fire Code (CFC) and is the administering agency for the CFC standards.

Applicable local (or locally enforced) requirements include:

- 2001 Edition of California Fire Code and all applicable NFPA standards (24 CCR Part 9);
- California Building Code Title 24, California Code of Regulations (24 CCR § 3, et seq.); and
- Uniform Fire Code, 1997.

SETTING

The proposed project would be located within the City of Blythe approximately five miles west of the center of the City.

BEP II would be a nominally rated 520 MW combined-cycle power plant, proposed as an addition to the existing Blythe Energy Project Phase I (BEP I), and would be located adjacent to the BEP I site boundary. BEP II would require no off-site linear facilities. The electrical interconnect will be with the existing Buck Blvd. substation on the northeast corner of the existing BEP I site and the natural gaswill interconnect with the existing BEP natural gas pipeline.

Fire support services to the site will be under the jurisdiction of the City of Blythe Fire Department (BFD). The BFD is located at 201 North Commercial Street approximately 5 miles away with a response time of 10 to 15 minutes (HRC 2000 and BFD 2003). The BFD has 30 trained volunteer firefighters, one full time fire marshal, and four fire engines (BEP II 2002d Page 7.6-7). The BFD has a mutual aid agreement with the Riverside County Fire Department (RCFD), which has two stations that are closer to the project site and would be the actual first responders. Fire Station No. 45 is the closest station to the site and is located at 17280 Hobsonway, approximately 0.75 miles west of the project site. The response time to the project site is estimated to be 3-5 minutes, and this station has two engines with two full-time trained firefighters. By the end of year 2003, the RCFD will upgrade the permanent staff at Station 45 from 2 to 3 firefighters per shift. All staff at station 45 are trained Emergency Medical Technicians (EMTs) (RCFD 2003a and 2003b). RCFD station 43 is located at 140 West Barnard Street, approximately 5 miles from the project site with an estimated response time of 7 to 10 minutes (HRC 2000 and RCFD 2003a). This station has two engines, two full-time trained firefighters, and up to 15 volunteers available during emergencies (BEP II 2002d Page 7.6-7). RCFD Station 44 is located in the town of Ripley, approximately 9 miles from the project site with an estimated response time of 15 minutes (HRC 2000). Staff determined that the response times of RCFD and BFD are adequate and consistent with the UFC and the NFPA. This information is summarized in Table 1, below.

A Fire Service Needs Assessment was prepared in April 2004 for BEP II and concluded that funding was required from the applicant to improve staffing, training and equipment in order to reduce impacts on the fire and emergency services to insignificance. The applicant has reached an agreement with the City of Blythe Fire Department and the Riverside County Fire Department on the additional funding that is necessary to reduce impacts from BEP II to insignificance. In conversations with the fire departments and in statements made by the City of Blythe at the January 26, 2005 Preliminary Staff Assessment workshop, both BFD and RCFD indicated that they were satisfied with the fire needs assessment and the level of funding that would come out of the applicant's community benefits package (BFD 2003 and RCFD 2003a,b).

WORKER SAFETY AND FIRE PROTECTION Table 1
Equipment and Personnel at BFD and RCFD

Station	Response Time	Distance to BEP II	Equipment	Number of Firefighters
Station No. 45 Hobsonway Blythe, CA (Riverside County Fire Department)	Approx. 3 to 5 minutes	Approx. 0.75 miles	2 – Type 1 Engine 1 – Type 4, Squad Vehicle	3 trained firefighters by 2004 15 to 20 volunteer firefighters
Station No. 43 140 West Barnard St. Blythe, CA (Riverside County Fire Department)	Approx. 5 to 7 minutes	Approx. 5 miles	2 – Type 1 Engine 1 – Water Tender 1 – Type 4, Squad Vehicle	2 trained firefighters 15 to 20 volunteer firefighters
Blythe Fire Department 201 North Commercial St. Blythe, CA (City of Blythe Fire Department)	Approx.10 to 15 minutes	Approx. 5 miles	1 – 50 foot ladder truck 4 – Fire Truck 1 – Squad Vehicle 1 – Quick Response Vehicle	33 trained volunteer firefighters 1 Fire Marshal

The BFD fire station is considered first responder for hazardous materials (HazMat) incidents, with backup service provided by the RCFD Stations 43 and 45. Currently, the BFD fire station and RCFD Stations 43 and 45 do not have any trained HazMat technicians. Additional response would be provided by the Riverside County HazMat Response Team located in Beaumont, approximately two hours away and manned with 4 HazMat technicians (BEP II 2002d Page 7.6-8, HRC 2000, and RCFD 2003b). The needs assessment conducted for BEP II indicated that this may not result in timely response as the expected hazardous materials event may last less than 1 hour. Staff proposes an additional Condition of Certification (**WORKER SAFETY-3**) that would require the applicant to train BEP II personnel to the level of HazMat Technicians, as was done at BEP I, in order to reduce the response time to an adequate one and reduce the potential impacts from a HazMat incident to insignificant.

IMPACTS

WORKER SAFETY

Industrial environments are potentially dangerous during 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 BEP II 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.

BEP II is also proposing to use a wet cooling system using water from the raw water storage system. The raw water will be obtained from on-site wells and therefore no off-site pipelines will be constructed. Two wells will be added by BEP II with similar characteristics to the two existing BEP I wells that are 600 and 620 feet deep. Compliance with worker safety regulations would protect workers from any hazards associated with the construction and operation of the cooling system and wells. This cooling option would not result in a significant impact to worker safety and health. Additionally, this cooling system will not represent a significant hazard and will not significantly impact fire protection services.

FIRE HAZARDS

During construction and operation of the proposed BEP II there is the potential for both small fires and major structural fires. Electrical sparks, combustion of fuel oil, natural gas, hydraulic fluid, mineral oil, insulating fluid at the power plant switchyard or flammable liquids, explosions, and over-heated equipment, may cause small fires. Major structural fires in areas without automatic fire detection and suppression systems are unlikely to develop at power plants. Fires and explosions of natural gas or other flammable gasses or liquids are rare. Compliance with all LORS will be adequate to assure protection from all fire hazards.

APPLICANT'S PROPOSED MITIGATION

WORKER SAFETY

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 BEP II encompasses construction and operation of a natural gas fired facility. Workers will be exposed to hazards typical of construction and operation of a gas-fired combined cycle facility.

Construction Safety Orders are published at 8 CCR 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 (8 CCR § 1509)
- Construction Fire Protection and Prevention Plan (8 CCR § 1920)

- Personal Protective Equipment Program (8 CCR §§ 1514 - 1522)
- Emergency Action Program and Plan

Additional programs under General Industry Safety Orders (8 CCR §§ 3200 to 6184), Electrical Safety Orders (8 CCR §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 CCR §§ 450 to 544) will include:

- Electrical Safety Program
- Motor Vehicle and Heavy Equipment Safety Program;
- Forklift Operation Program;
- Excavation/Trenching Program;
- Fall Prevention Program;
- Scaffolding/Ladder Safety Program;
- Articulating Boom Platforms Program;
- Crane and Material Handling Program;
- Housekeeping and Material Handling and Storage Program;
- Respiratory Protection Program;
- Employee Exposure Monitoring Program;
- Hand and Portable Power Tool Safety Program;
- Hearing Conservation Program;
- Back Injury Prevention Program;
- Hazard Communication Program;
- Heat and Cold Stress Monitoring and Control Program; and
- Pressure Vessel and Pipeline Safety Program.

The AFC includes adequate outlines of each of the above programs (BEP II 2002d, Section 7.10.2.1). Prior to the start of construction of the BEP II, detailed programs and plans will be provided pursuant to the Condition of Certification **WORKER SAFETY-1**.

Operations and Maintenance Safety and Health Program

Prior to the start of operations at the BEP II, 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 (8 CCR § 3203);
- Emergency Action Plan (8 CCR § 3220);
- Hazardous Materials Management Program;
- Fire Protection and Prevention Program (8 CCR § 3221); and
- Personal Protective Equipment Program (8 CCR §§ 3401 to 3411).

In addition, the requirements under General Industry Safety Orders (8 CCR §§ 3200 to 6184), Electrical Safety Orders (8 CCR §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 CCR §§ 450 to 544) will be applicable to the project. Written safety programs for the BEP II, which the applicant will develop, will ensure compliance with the above-mentioned requirements.

The AFC includes adequate outlines of the Injury and Illness Prevention Program, Emergency Action Plan, Fire Protection and Prevention Program, and Personal Protective Equipment Program (BEP II 2002d, Section 7.10.2.2). Prior to operation of the BEP II, 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 expanded Construction and Operations Illness and Injury Prevention Programs to Cal/OSHA for review and comment 30 days prior to construction and operation of the project, respectively.

The IIPP will do the following (as presented in the AFC for BEP II 2002d Section 7.10.2.2.1):

- Identify person(s) with authority and responsibility for implementing the program;
- establish a safety and health policy of the plan;
- define work rules and safe work practices for construction activities;
- establish a system for ensuring that employees comply with safe and healthy work practices;
- establish a system for facilitating employer-employee communications;
- implement procedures for identifying and evaluating workplace hazards and developing necessary program(s);
- implement methods for correcting unhealthy/unsafe conditions in a timely manner;
- determine and establish training and instruction requirements and programs; and
- specify safety procedures.

Emergency Action Plan

California regulations require an Emergency Action Plan (8 CCR § 3220). The AFC contains a satisfactory outline for an emergency action plan (BEP II 2002d Section 7.10.2.2.3).

The EAP will do the following :

- establish emergency escape procedures and emergency escape route for the facility;
- determine procedures to be followed by employees who remain to operate critical plant operations before they evacuate;
- provide procedures to account for all employees and visitors after emergency evacuation of the plant has been completed;
- specify rescue and medical duties for assigned employees;
- identify fire and emergency reporting procedures to regulatory agencies;
- develop alarm and communication system for the facility;
- establish a list of personnel to contact for information on the plan contents;
- provide emergency response procedures for ammonia, natural gas releases, or other hazardous chemicals that could exceed plant boundaries;
- include a copy of the Hazardous Materials Management Program;
- develop a Spill Prevention Control and Countermeasure (SPCC) Plan; and
- determine and establish training and instruction requirements and programs.

Fire Prevention Plan

California Code of Regulations requires an Operations Fire Prevention Plan (8 CCR § 3221). The AFC describes a proposed Fire Protection and Prevention Plan which is acceptable to staff (BEP II 2002d Section 7.10.2.2.2). The plan will include the following topics:

- determine general program requirements;
- develop good housekeeping practices and procedures;
- establish employee alarm and/or communication system(s);
- provide portable fire extinguishers at appropriate site locations;
- locate fixed fire fighting equipment in suitable areas;
- specify fire control requirements and procedures;
- establish proper flammable and combustible liquid storage facilities;
- identify the location and use of flammable and combustible liquids;
- provide proper dispensing facilities for flammable materials;
- determine proper disposal requirements for flammable liquids;
- identify proper servicing and refueling locations; and
- establish and determine training and instruction requirements and programs.

Staff proposes that the applicant submit a final Fire Protection and Prevention Plan to the California Energy Commission Compliance Project Manager (CPM) for review and approval and to the City of Blythe Fire Department for review and comment to satisfy proposed Conditions of Certification **WORKER SAFETY-1** and **WORKER SAFETY-2**.

Staff has found, however, that the potential for both work-related and non-work related heart attacks exists at power plants. In fact, staff's research on the frequency of EMS response to gas-fired power plants shows that the majority of the responses for cardiac emergencies involved non-work related incidences including visitors. The need for prompt response within a few minutes is well documented in the medical literature. Staff finds that the quickest and most effective medical intervention for heart attacks can only be achieved with the use of an on-site cardiac defibrillator; the response from an off-site provider would take longer regardless of the provider location and could be too late to convert a cardiac arrhythmia to normal sinus rhythm. This fact is also well documented and serves as the basis for many private and public locations (e.g., airports, factories, government buildings) maintaining on-site cardiac defibrillation devices. The Energy Commission maintains such a device at its building in Sacramento. Staff thus finds that with the advent of modern cost-effective cardiac defibrillation devices, it is proper in a power plant environment to maintain such a device on-site in order to convert cardiac arrhythmias resulting from industrial accidents or other non-work related causes (Cummins 1987, Marenco 2001). Therefore, an additional Condition of Certification (**WORKER SAFETY-4**) is proposed which would require that a portable automatic cardiac defibrillator be located on site.

Personal Protective Equipment Program

California regulations require Personal Protective Equipment (PPE) and first aid supplies whenever hazards are present that, due to process, environment, chemicals or mechanical irritants, can cause injury or impair bodily function as a result of absorption, inhalation or physical contact (8 CCR section 3380 to 3400). The BEP II operational environment will require PPE.

All safety equipment must meet National Institute of Safety and Health (NIOSH) or ANSI standards and will carry markings, numbers, or certificates of approval. Respirators must meet NIOSH and Cal/OSHA standards. Each employee must be provided with the following information 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 provides employees with the information and training necessary to protect them from potential workplace hazards.

Written Safety Program

In addition to the specific plans listed above, additional LORS apply to the project, 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, but are not limited to, the following:

- Fall Protection Program;

- Hot Work Safety Program;
- Confined Space Entry Program;
- Hearing Conservation Program;
- Hazard Communication Program;
- Process Safety Management (PSM) Program; and
- Contractor Safety Program, including the Lockout/Tagout program.

Safety Training Programs

Employees will be trained in the safe work practices described in all the above-referenced safety programs as well as all safety training in programs not listed above but required by Cal OSHA regulations.

FIRE PROTECTION

Staff reviewed the information provided in the AFC to determine if available fire protection services and equipment would adequately protect workers, and to determine the project's impact on fire protection services in the area (BEP II 2002d, Section 7.10.2.2.2). The project will 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 the event of a major fire, fire support services, including trained firefighters and equipment for a sustained response, would be provided by the City of Blythe Fire Department and Riverside County Fire Department.

During construction portable fire extinguishers will be provided in accordance with Cal-OSHA requirements at locations including portable office spaces, welding and braising areas, flammable chemical storage areas, and mobile equipment. A 4,000 gallon water pumping truck will be located on-site until the permanent fire pump system is operational (BEP II 2002d Page 7.10-7).

The information in the AFC indicates that the project intends to meet the fire protection and suppression requirements of the California Fire Code, all applicable recommended NFPA standards (including Standard 850 addressing fire protection at electric generating plants), and all Cal-OSHA requirements. Elements include both fixed and portable fire extinguishing systems. The BEP II fire protection system may also be interconnected to the existing BEP fire protection system. The fire water will be supplied from the raw water storage tank constructed as part of the BEP II project, with a minimum supply of 300,000 gallons dedicated for fire suppression purposes. The raw water storage tank has a holding capacity of 600,000 gallons, and make-up water will be provided by two on-site wells and pumps each capable of restoring water at a total maximum rate of 3,000 gallons/minute which is above the designed flow capacity of the 2500 gpm fire protection pump (BEP II 2002d, Page 2-17 and BEP II 2003b, DR-187). It is important to note that the water rights issue has yet to be resolved and therefore the applicant may or may not have the unrestricted right to use groundwater for fire protection. Please refer to the **Soil & Water Resources** section of the FSA for further discussion of water rights. When this issue is resolved, a legal and adequate supply of water for the project must be identified.

The firewater pumping system consists of an electric motor-driven fire pump, an emergency backup driven by a diesel engine, and an electric jockey pump to maintain the pressure in the main fire loop. The fire loop pumps have a maximum capacity each of 2500 gallons/minute to deliver water to the fire protection water piping network. The two electric well pumps at BEP I have a maximum capacity of 3000 gallons/minute each. Staff finds that this system will provide more than an adequate quantity of fire-fighting water to facility fire hydrants, and automatic fire suppression (sprinkler/deluge) systems.

A deluge type fire protection system will be provided for the turbine and generator bearing areas, lube oil lines, and lube oil tank and filter area.

Fire hydrants and portable fire extinguishers will be located throughout the power plant site at appropriate intervals according to code. The fire plant loop will also supply a vapor suppression system at the aqueous ammonia storage tank area.

In addition to the fixed fire protection system, smoke detectors, flame detectors, temperature detectors, and appropriate class of service portable extinguishers will be located throughout the facility at code-approved intervals. These systems are standard requirement by the NFPA and the UFC and staff finds that they will ensure adequate fire protection.

The applicant will be required to provide the final Fire Protection and Prevention Program to staff and to both the City of Blythe Fire Department and Riverside County Fire Department, prior to construction and operation of the project, to confirm the adequacy of the proposed fire protection measures.

CUMULATIVE IMPACTS

Staff reviewed the potential for the construction and operation of BEP II, combined with existing industrial facilities and expected new facilities, to result in impacts on the fire and emergency service capabilities of the City of Blythe Fire Department and Riverside County Fire Department. Staff also reviewed the Fire Services Needs Assessment (April 2004) and determined that without mitigation, cumulative impacts on the fire and emergency services would be significant. However, the applicant has entered into an agreement with the City of Blythe Fire Department to fund those needs, thus mitigating the impacts to less that a significant level. Staff also proposes Condition of Certification **WORKER SAFETY-3** that requires the applicant to train BEP II personnel to the level of HazMat Technicians, as was done at BEP I, in order to reduce the response time to an adequate one and reduce the potential impacts from a HazMat incident to insignificant.

In regards to water, the availability of fire water supplies remains an issue.

FACILITY CLOSURE

The project owner/operator is responsible for maintaining an operational fire protection system during closure activities. The project must also maintain compliance with all applicable health and safety LORS during that time. A facility closure plan will be developed prior to closure to incorporate these requirements.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

AGENCY COMMENTS

Mr. Butch Hull of the City of Blythe commented that the City had entered into an agreement with the applicant for funds to address the needs of the BFD identified in the Fire Needs Assessment and that the funding was adequate.

Response: none needed

PUBLIC COMMENTS

None

APPLICANT'S COMMENTS

The Applicant made several written comments in an April 2004 submittal and these were reiterated at the Janaury 26, 2005 Preliminary Staff Assessment Workshop. These comments included:

a. Checking that the 2001 edition of the California Fire Code was correctly referenced;

b. Correcting an error about the electrical interconnect found in the section "Setting";

c. Revising the reference to the need for a Fire Needs Assessment in the PSA because the assessment has been completed and an agreement with the BFD has been reached;

d. Revising the text to reflect that two additional wells will be added on-site instead of one additional well;

e. clarifying that the BEP I raw water and fire water systems ***may*** *be interconnected with the BEP II systems;*

f. Clarifying that although the groundwater pumps to be installed on-site are capable of a combined flow of 6,000 gpm, the fire suppression system is only capable of providing 2,500 gpm; and

g. clarifying that the deluge system for the CT will also be used for the generator bearing areas, lube oil lines, and lube oil and filter areas.

RESPONSE: All changes and clarifications have been made. The 2001 California Fire Code is the correct version.

CONCLUSION AND RECOMMENDATIONS

If the Applicant for the proposed BEP II provides a Project Construction Safety and Health Program and a Project Operations and Maintenance 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 if the applicant trains the BEP II staff to the level of Hazmat Technicians (Condition of Certification **WORKER SAFETY –3**), BEP II staff would be able to respond quickly and

adequately to hazardous materials incidents. Staff therefore finds that with **WORKER SAFETY-3** and with the applicant's proposed mitigation regarding hazardous materials spills, the impacts of an on-site hazardous material spill would be reduced to an insignificant level. Staff also notes that with the advent of modern cost-effective cardiac defibrillation devices, it is proper in a power plant environment to maintain such a device on-site in order to convert cardiac arrhythmias resulting from industrial accidents or other non-work related causes (Cummins 1987, Marenco 2001). Therefore, an additional Condition of Certification (**WORKER SAFETY-4**) is proposed which would require that at least one portable automatic cardiac defibrillator be located on site during both construction and operations. Finally, staff proposes Condition of Certification **WORKER SAFETY-5** which requires that a safety monitor will be hired to conduct routine safety inspections during both construction and commissioning. Recent accidents at California Energy Commission-certified power plants and on-site safety audits at several power plants under construction have demonstrated that the complexity in building a power plant requires increased vigilance and expertise in safety.

In regards to fire water supplies, the availability of water remains an issue. If groundwater use is restricted or prohibited outright, the project will need to identify other sources for fire water supplies or the project cannot be built.

If the Energy Commission certifies the project, staff recommends that the following proposed Conditions of Certification be adopted. The proposed Conditions of Certification provide assurance that the Construction Safety and Health Program and the Operations and Maintenance 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.

In regards to off-site fire protection and emergency medical services, the applicant and the City of Blythe have entered into an agreement to fund certain equipment and training identified in the Fire Needs Assessment. The resultant upgrading of the response capability of both the BFD and the RCFD combined with fixed fire-suppression systems at the power plant will result in an insignificant impact on local fire departments.

PROPOSED CONDITIONS OF CERTIFICATION

WORKER SAFETY-1 The project owner shall submit to the Compliance Project Manager (CPM) a copy of the Project Construction Safety and Health Program containing the following:

- A Construction Personal Protective Equipment Program;
- A Construction Injury and Illness Prevention Program;
- A Construction Emergency Action Plan; and
- A Construction Fire Protection and Prevention Plan.

The Personal Protective Equipment Program and the Injury and Illness Prevention Program shall be submitted to the CPM for review and approval

concerning compliance of the program with all applicable Safety Orders. The Construction Emergency Action Plan and the Fire Protection and Prevention Plan shall be submitted to the City of Blythe Fire Department and the Riverside County Fire Department for review and comment prior to submittal to the CPM for approval.

Verification: At least 30 days prior to the start of construction, the project owner shall submit to the CPM for review and approval a copy of the Project Construction Safety and Health Program. The project owner shall provide a letter from the City of Blythe Fire Department and the Riverside County Fire Department stating that they have reviewed and commented on the Construction Fire Protection and Prevention Plan and Emergency Action Plan.

WORKER SAFETY-2 The project owner shall submit to the CPM a copy of the Project Operations and Maintenance Safety and Health Program containing the following:

- An Operation Injury and Illness Prevention Plan;
- An Emergency Action Plan;
- Hazardous Materials Management Program;
- Fire Protection and Prevention Program (8 CCR § 3221); and
- Personal Protective Equipment Program (8 CCR §§ 3401-3411).

The Operation Injury and Illness Prevention Plan, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted to the 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 to the City of Blythe Fire Department and the Riverside 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 for approval a copy 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 City of Blythe Fire Department and the Riverside County Fire Department stating that they have reviewed and commented on the Operations Fire Protection and Prevention Plan and the Emergency Action Plan.

WORKER SAFETY-3 Prior to the delivery of any hazardous materials to the project site, the project owner shall train the personnel at the BEP II facility to the level of Hazmat Technicians capable of responding to hazardous materials incidents.

Verification: At least thirty (30) days prior to the delivery of hazardous materials to the site, the project owner shall provide the CPM with a letter indicating the number of employees that have been trained as Hazmat Technicians.

WORKER SAFETY-4 The project owner shall provide a portable automatic cardiac defibrillator on site during construction and operation.

Verification: At least 30 days prior to the start of site mobilization the project owner shall submit to the CPM proof that a portable automatic cardiac defibrillator exists on site.

WORKER SAFETY-5 The project owner shall ensure that a CPM approved Safety Monitor(s) conducts an on-site safety inspection at least once a week during construction of permanent structures, and commissioning, of the power plant unless a lesser number of inspections are approved by the CPM. The CPM may also require a similar inspection and report concerning linear facilities.

The Safety Monitor shall keep the CBO fully informed regarding safety related matters and coordinate with the CBO concerning on-site safety inspections, and conduct a final safety inspection prior to issuance of the Certificate of Occupancy by the CBO. The Safety Monitor shall be retained until cessation of construction and commissioning activities, and issuance of the Certificate of Occupancy, unless otherwise approved by the CPM.

The Safety Monitor(s) shall also:

- Inform the construction supervisors of any construction or commissioning problems that could pose a future danger to life or health, consulting with the CBO as necessary.
- After consultation with the CBO, have the authority to temporarily stop construction or commissioning activities involving possible safety violations or unsafe conditions that may pose an immediate or future danger to life or health, until the problem is resolved to the satisfaction of the Safety Monitor and CBO.
- Consult with the CBO to determine when construction may resume unless the problem is corrected immediately and to the satisfaction of the Safety Monitor and/or CBO.
- Inform the CPM within 24 hours of any temporary halt in construction or commissioning activities.
- Be available to inspect the site whenever necessary in addition to the minimum weekly basis during construction and commissioning as determined in consultation with the CBO and CPM.
- Verify that a safety program for the project that complies with CAL-OSHA & Federal regulations related to power plant projects has been implemented.
- Verify that all Federal and CALOSHA requirements are complied with during the construction and installation of all permanent structures (including safety aspects of electrical installations).
- Verify that all construction and commissioning workers and supervisors receive adequate safety training.

- Conduct accident and safety-related incident investigations, emergency response reports for injuries, and inform the CPM of all safety-related incidents.
- Verify that all the plans identified in **Worker Safety-1** are implemented.

The Safety Monitor shall be qualified regarding the following:

- Safety issues related to equipment, pipelines, etc,
- LORS applicable to workplace safety and worker protection
- Workplace hazards typically associated with power production
- Lock-out / tag-out and confined spaces control systems

Verification: The project owner shall submit the Safety Monitor(s) resume(s) to the CPM for approval at least 30 days prior to site mobilization. One or more individuals may hold this position.

The Safety Monitor shall submit in the MCR a monthly safety inspection report to include the following items:

1. Record of all employees trained for that month (all records shall be kept on site for the duration of the project);
2. Summary report of safety management actions that occurred during the month;
3. Report of any continuing or unresolved situations or incidents that may pose danger to life or health;
4. Report of accidents and injuries that occurred during the month.

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Engineering

Assessment

FACILITY DESIGN

Testimony of Shahab Khoshmashrab, Al McCuen and Steve Baker

INTRODUCTION

Facility Design encompasses the civil, structural, mechanical and electrical engineering design of the project. The purpose of the Facility Design analysis is to:

- verify that the laws, ordinances, regulations and standards (LORS) applicable to the engineering design and construction of the project have been identified;
- verify that the project and ancillary facilities have been described in sufficient detail, including proposed design criteria and analysis methods, to provide reasonable assurance that the project can be designed and constructed in accordance with all applicable engineering LORS, and in a manner that assures public health and safety;
- determine whether special design features should be considered during final design to deal with conditions unique to the site which could influence public health and safety; and
- describe the design review and construction inspection process and establish Conditions of Certification that will be used to monitor and ensure compliance with the 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).

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

Caithness Blythe II, LLC proposes to construct and operate a nominally rated 520 megawatt combined-cycle power plant known as the Blythe Energy Project Phase II (BEP II). The project will be located approximately five miles west of the City of Blythe in Riverside County. The site will occupy approximately 76 acres on a 152-acre site (BEP II 2004d, AFC § 2.2.1), and will lie in seismic zone 3. For more information on the site and related project description, please see the **Project Description** section of this document. References to "the City" and "the County" designate the City of Blythe and Riverside County, respectively. Additional engineering design details are contained in the Revised Application for Certification (AFC), in Appendices 8A through 8E (BEP II 2002d).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

Lists of LORS applicable to each engineering discipline (civil, structural, mechanical and electrical) are described in the AFC (BEP II 2002d, Appendices 8A through 8E). Some of these LORS include the California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations), and guidelines promulgated by the American National Standards Institute (ANSI), American Society of Mechanical Engineers (ASME), American Society for Testing and Materials (ASTM) and American Welding Society (AWS).

ANALYSIS

The basis of this analysis is the applicant's analysis and proposed construction methods and 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 and water pipelines. The applicant proposes to use accepted industry standards (see AFC Appendices 8A through 8E 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, would most likely comply with all applicable site preparation LORS, and proposes Conditions of Certification (see below and the **Geology and Paleontology** section of this document) to ensure compliance.

MAJOR STRUCTURES, SYSTEMS AND EQUIPMENT

Major structures, systems and equipment are defined as those structures and associated components or equipment that are necessary for power production and are costly to repair or replace, that require a long lead time to repair or replace, or that are used for the storage, containment, or handling of hazardous or toxic materials, or may become potential health and safety hazards if not constructed according to the applicable engineering LORS. 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 2001 edition of the California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations), which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and other applicable codes and standards in effect at the time design and construction of the project actually commences. In the event the initial designs are submitted to the Chief Building Official (CBO) for review and approval when the successor to the 2001 CBSC is in effect, the 2001 CBSC 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 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.

PROJECT QUALITY PROCEDURES

The AFC (BEP II 2002d, § 8.1.5) states that a project Quality Program will be used on the project to ensure that systems and components will be designed, fabricated, stored, transported, installed and tested in accordance with the technical codes and standards appropriate for a power plant. Compliance with design requirements will be verified through an appropriate program of inspections and audits. Employment of this quality assurance/quality control (QA/QC) program would ensure that the project is actually designed, procured, fabricated, and installed as contemplated in this analysis.

COMPLIANCE MONITORING

Under Section 104.2 of the CBC, the CBO 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 CBO 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 to 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, that would be difficult to reverse or correct, may proceed without prior approval of plans by the CBO. Those elements of construction that are not difficult to reverse 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 subsequent 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:

- 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.

RESPONSE TO THE APPLICANT'S COMMENTS

The applicant submitted comments regarding **Facility Design** as described by the Preliminary Staff Assessment (BEP II 2004e). Staff has reviewed those comments and incorporated appropriate revisions. Following are staff's responses to the comments:

Numbered Comments:

1. The site acreage has been revised to reflect the current proposal to occupy 76 acres on a 152-acre site (see above).
2. Revision was not made; staff disagrees with adding the applicant as a party to the MOU. The purpose of the MOU is to outline the Energy Commission's expectations of the CBO as its delegate agent. Furthermore, signing an MOU with the applicant would violate the independence of the CBO.
3. Revision was not made. Those elements of construction needing modification in order to comply with design changes can not be predetermined as they are unpredictable and will occur after project construction commences.
4. Revision was not made; periodic evaluation of the CBO's performance by the applicant is not necessary. The purpose of the **Facility Design** Conditions of Certification is for the Energy Commission to evaluate, via the CBO, the performance of the project owner in regard to compliance with the applicable codes, not vice versa. The project owner cannot influence the CBO's function and thus cannot participate as an auditor of the CBO. The Energy Commission may provide audits of the CBO's performance, but not in partnership with the project owner or its representatives. This has been the staff's standard practice and should remain unchanged.
5. Revision was not made; a review committee to render interpretations of the code is not necessary. The above **Facility Design** conditions, as written, allow the project owner, at any time before and during construction, to request that any such issues be brought to the attention of the CPM and be resolved with the involvement of Energy Commission representatives. This is the staff's standard practice and has worked well in numerous licensing cases in the past.

Comments regarding the proposed Conditions of Certification:

GEN-1, **GEN-8** & **CIVIL-4**: The edition of the CBSC has been revised to reflect the applicable version.

GEN-1:

Summary of comment: The applicant does not see the need to require confirmation to the Energy Commission that all contracts between the project owner and its contractors, subcontractors and suppliers include the specific requirements from condition **GEN-1**.

Response: Revision was not made. Staff crafted this text as the result of concerns with the Blythe I project, when the project owner expressed its frustration with difficulties meeting the code requirements through its contractors and subcontractors. The project owner representatives for the Blythe I project stated that some of their contractors and subcontractors were not aware of the California code requirements. The project owner requested that this text be added.

Summary of comment: Clarify who the title "responsible design engineer" used throughout the PSA refers to.

Response: Revision has been made (see below); the responsible design engineer refers to each one of the responsible structural, civil, mechanical, and electrical engineers.

GEN-2:

Summary of comment: Modify **Facility Design Table 1** to incorporate the items revised or added.

Response: Appropriate revisions to this table have been made (see below). However, specifying the type of chemical used in the ammonia storage system and the numerical values for pressure and diameter of the high pressure piping systems are not necessary, as they will be addressed during the detailed design and construction.

GEN-4:

Summary of comment: Energy Commission is using as a basis for the resident engineer's (RE) responsibilities a section of the code that applies to essential services buildings (CBC Section 4-209). Blythe 2 project is not an essential services facility.

Response: Staff disagrees; portions of a power plant such as Blythe 2 are considered essential facilities. Both fire suppression systems and hazardous materials will be present in numerous areas throughout the facility (such as hazardous chemicals and high pressure gases and fluids). Also, the power plant shall be capable of both activating its emergency response systems and providing services to the public after a disaster (earthquake, flooding, terrorist attack…) if needed.

Moreover, the 2001 CBC Sections 104.2.2 (Deputies) and 106.3.4 (Architect or Engineer of Record) authorize the CBO to appoint deputies (i.e., the RE) if necessary to assure the goals of the code are met, regardless of the essentiality of the services provided. The complex engineering nature of this project necessitates that the Energy Commission exercise this right. Note that the RE is employed by the project owner with the purpose of providing independent services to ensure project compliance with the LORS enforced by the CBO.

In addition to the above requirements, the need for the independent supervision provided by an RE during design and construction of such an engineering intensive

project stems from the requirements and procedures of the 2005 California State Professional Engineers Act (Business and Professions Code, §§ 6700-6799).

Summary of comment: The applicant questions the need for an RE.

Response: As explained above, for a large and complex power plant project such as Blythe 2, a resident engineer is essential for establishing and maintaining communication among the construction personnel, the contractors and subcontractors, the CBO, and the responsible engineers who may work in distant locations. This individual should be a technical expert in the area of power plant design and construction in California (a civil or a structural engineer) with a valid California engineering license. He/she may be required to seal and sign design and construction documents that otherwise would have to be signed by engineers in far away locations who may not be actively involved in the daily construction work. This practice helps to reduce the chance of any non-compliance activities that could occur otherwise. Having a resident engineer in or near the project site is crucial to ensuring the project owner's compliance with the codes in a timely manner.

Summary of comment: The code does not specify that the RE has the authority to halt construction.

Response: Staff disagrees. As a deputy of the CBO (see above), the resident engineer has the authority to stop work according to the 2001 CBC Section 104.2.4 (Stop Orders), in order to help prevent any non-compliance activity from occurring. Some permanent facilities can be very difficult to reverse or correct.

Summary of comment: The applicant questions the requirement that the CBO approve qualifications of the responsible engineers (including the RE).

Response: In some cases in the past, non-California registered engineers prepared design documents not in compliance with the codes and in many of those cases the plans were implemented as such. To help prevent this practice, by approving their qualifications, the CBO in advance ensures that engineers (including the RE) are properly licensed and experienced in their respective disciplinary areas.

GEN-6:

Summary of comment: This condition requires that all discrepancies be brought to the immediate attention of the RE for correction... However, CBC Section 1701.3 requires that discrepancies be brought to the immediate attention of the contractor for correction, then, if uncorrected, to the proper design authority.

Response: As explained above, the RE is the link between the construction crew, the contractors and the responsible engineers (design authorities). The Energy Commission process, in addition to being in line with the code, ensures good control and efficiency.

GEN-7:

Summary of comment: The CBC does not require that corrective actions be approved by the CBO.

Response: Staff disagrees. The 2001 CBC, Section 108.4 clearly states that any work that is not in compliance shall be corrected and reevaluated by the CBO for approval. Submitting corrective actions for CBO approval is the first logical step to meeting this requirement.

GEN-8:

Summary of comment: The code does not mention that the project owner shall obtain CBO's final approval of completed work that has undergone CBO design review and approval.

Response: Staff disagrees. This requirement is made clear in the 2001 CBC Sections 106.4.1 (Permits Issuance), 108.5.6 (Final Inspections), 109 (Certificate of Occupancy), 1702 (Structural Observation) and 3318 (Completion of Work). The requirement that the project owner issue a signed statement that the work conforms to final approved plans ensures that the project owner or its representatives have implemented the final approved plans. Without this, no such assurance exists.

Note that the staff-recommended **Facility Design** conditions as outlined in this staff assessment are consistent with the current Energy Commission practices. Finally, note that 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 provisions [2001 CBC, Section 4-203 – Interpretation].

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. Even though 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 2001 CBSC (or successor standard, if such is in effect when the initial project engineering designs are submitted for review); and
3. The CBO shall review the final designs, conduct plan checking and perform field inspections during construction. Energy Commission staff shall audit and monitor the CBO to ensure satisfactory performance.

CONDITIONS OF CERTIFICATION

GEN-1 The project owner shall design, construct and inspect the project in accordance with the 2001 California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations), which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable engineering LORS in effect at the time initial design plans are submitted to the CBO for review and approval. (The CBSC 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.

In the event that the initial engineering designs are submitted to the CBO when a successor to the 2001 CBSC is in effect, the 2001 CBSC 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.

The project owner shall ensure that all contracts with contractors, subcontractors and suppliers shall clearly specify that all work performed and materials supplied on this project are to comply with the applicable codes listed above.

Verification: Within 30 days after execution of any contract or subcontract, the project owner shall submit to the CPM a copy of that portion of the contract or subcontract containing language specifying that work under that contract or subcontract shall comply with the applicable codes listed in this Condition of Certification. 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 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 [2001 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 **Facility Design 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	2
Combustion Turbine Generator Foundation and Connections	2
Steam Turbine (ST) Foundation and Connections	1
Steam Turbine Generator Foundation and Connections	1
Auxiliary Transformer Foundation and Connections	2
CT Inlet Air Plenum Structure, Foundation and Connections	2
Heat Recovery Steam Generator (HRSG) Structure, Foundation and Connections	2
HRSG Stack Structure, Foundation and Connections	2
Cooling Tower Structure, Foundation and Connections	1
Boiler Feed Pump Foundation and Connections	3
Condensate Extraction Pump Foundation and Connections	3
Circulating Water Pump Foundation and Connections	2
Steam Surface Condensers Foundation and Connections	2
Condenser Evacuation Pump Foundation and Connections	2
Turbine Hall Overhead Crane	1
Continuous Emission Monitoring System Structure, Foundation and Connections	2
Ammonia Storage System Foundation and Connections	1

Equipment/System	**Quantity (Plant)**
Circulating Water System Dosing Foundation and Connections	1
Water Steam Cycle Dosing Foundation and Connections	1
High, Intermediate and Low Pressure Steam Systems	1 Lot
Reheat Steam System	1 Lot
Condensate and Feed Systems	1 Lot
Water Treatment System Brine Concentrator Foundation and Connections	1
Water Treatment System Demineralizer Foundation and Connections	1
Raw Water Storage Tank Foundation and Connections	1
Demineralized Water Storage Tank Foundation and Connections	1
Fuel Gas Heater Foundation and Connections	2
Fuel Gas Scrubbing and Regulating System Foundation and Connections	1
Fire Protection System Pumps Foundation and Connections	2
Workshop/Storage Building Structures, Foundation and Connections	1
Fire Pump House Foundation and Connections	1
Control Room Building Structures, Foundation and Connections	1
Boiler Feedwater Pump House Structures, Foundation and Connections	1
Secondary Unit Substation/Transformer	2
Combustion Turbine Electrical/Control Center	2
Steam Turbine Electrical/Control Center	2
Air Compressor Foundation and Connections	2
CT Static Starter Skid Foundation and Connections	2
Switchgear Equipment Building Structure, Foundation and Connections	2
CT Generator Step-up Transformer Foundation and Connections	2
ST Generator Step-up Transformer Foundation and Connections	1
Air Receiver Foundation and Connections	1
Air Dryer Foundation and Connections	1
Closed Cycle Cooling Water Heat Exchanger Foundation and Connections	2
Closed Cycle Cooling Water Pump Foundation and Connections	2
Inlet Air Chilling (or Evaporative Cooling) Skid Foundation and Connections	2
Water Treatment Systems Skid Foundation and Connections	1 Lot
Potable Water Systems	1 Lot
Drainage Systems (including sanitary drain and waste)	1 Lot
High Pressure and Large Diameter Piping	1 Lot
HVAC and Refrigeration Systems	1 Lot
Temperature Control and Ventilation Systems (including water and sewer connections)	1 Lot
Building Energy Conservation Systems	1 Lot
Substation/Switchyard, Buses and Towers (Excluding Buck Blvd.	1 Lot

Equipment/System	**Quantity (Plant)**
Substation)	
Electrical Duct Banks	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 based on a CPM approved agreement. These fees may be consistent with the fees listed in the 2001 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. Payments to the CBO shall in no way affect or diminish the independence of 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. The project owner shall provide a copy of the payment agreement to the CPM for review and approval prior to execution.

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.

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 rough grading, the project owner shall assign at least one of each of the following California registered engineers to the project: A) a civil engineer; B) a soils engineer, or a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; and C) an engineering geologist. Prior to the start of construction, the project owner shall assign at least one of each of the following California registered engineers to the project: D) a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; E) a mechanical engineer; and F) an electrical engineer. [California Business and Professions Code section 6704 et seq., and sections 6730, 6731 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 structural engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g., proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer.

The 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 [2001 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.

A. The civil engineer shall:

1. Review the Foundation Investigations Report, Geotechnical Report or Soils Report prepared by the soils engineer, the geotechnical engineer, or by a civil engineer experienced and knowledgeable in the practice of soils engineering;
2. Design, or be responsible for 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
3. Provide consultation to the RE during the construction phase of the project and <u>when necessary,</u> recommend changes in the design of the civil works facilities and changes in the construction procedures.

B. The soils engineer, geotechnical engineer, or civil engineer experienced and knowledgeable in the practice of soils engineering, shall:

1. Review all the engineering geology reports;
2. Prepare the Foundation Investigations Report, Geotechnical Report or Soils Report containing field exploration reports, laboratory tests and engineering analysis detailing the nature and extent of the soils that may be susceptible to liquefaction, rapid settlement or collapse when saturated under load [2001 CBC, Appendix Chapter 33, Section 3309.5, Soils Engineering Report; Section 3309.6, Engineering Geology Report; and Chapter 18, Section 1804, Foundation Investigations];

3. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 2001 CBC, Appendix Chapter 33; Section 3317, Grading Inspections (depending on the site conditions, this may be the responsibility of either the soils engineer or engineering geologist or both); and
4. Recommend field changes to the civil engineer and RE.

This engineer shall be authorized to halt earthwork and to require changes if site conditions are unsafe or do not conform to predicted conditions used as a basis for design of earthwork or foundations [2001 CBC, section 104.2.4, Stop orders].

C. The engineering geologist shall:

1. Review all the engineering geology reports and prepare final soils grading report; and
2. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 2001 CBC, Appendix Chapter 33; Section 3317, Grading Inspections (depending on the site conditions, this may be the responsibility of either the soils engineer or engineering geologist or both).

D. The structural or civil engineer shall:

1. Be directly responsible for the design of the proposed structures and equipment supports;
2. Provide consultation to the RE during design and construction of the project;
3. Monitor construction progress to ensure compliance with engineering LORS;
4. Evaluate and recommend necessary changes in design; and
5. Prepare and sign all major building plans, specifications and calculations.

E. The mechanical engineer shall be responsible for, and sign and stamp a statement with, each mechanical submittal to the CBO, stating that the proposed final design plans, specifications, and calculations conform to all of the mechanical engineering design requirements set forth in the Energy Commission's Decision.

F. The electrical engineer shall:

1. Be responsible for the electrical design of the project; and
2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

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, resumes and registration numbers of the responsible civil

engineer, soils (geotechnical) engineer and engineering geologist assigned to the project.

At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of construction, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible structural engineer, mechanical engineer and electrical engineer assigned to the project.

The project owner shall notify the CPM of the CBO's approvals of the responsible engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-6 Prior to the start of an activity requiring special inspection, 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 2001 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.
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 [2001 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 [2001 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall 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 the CBO's approval.

GEN-8 The project owner shall obtain the CBO's final approval of all completed work that has undergone CBO design review and approval. The project owner shall request the CBO to inspect the completed structure and review the submitted documents. The project owner shall notify the CPM after obtaining the CBO's final approval. The project owner shall retain one set of approved engineering plans, specifications and calculations (including all approved changes) at the project site or at another accessible location during the operating life of the project [2001 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, Geotechnical Report or Foundation Investigations Report required by the 2001 CBC [Appendix Chapter 33, Section 3309.5, Soils Engineering Report; Section 3309.6, Engineering Geology Report; and Chapter 18, Section 1804, Foundation Investigations].

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 earthwork and construction in the affected areas when the responsible soils engineer, geotechnical engineer, or the civil engineer experienced and knowledgeable in the practice of soils engineering identifies unforeseen adverse soil or geologic conditions. The project owner shall submit modified plans, specifications and calculations to the CBO based on these new conditions. The project owner shall obtain approval from the CBO before resuming earthwork and construction in the affected area [2001 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 2001 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.

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 [2001 CBC, Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The project owner shall prepare a written report, with copies to the CBO and the CPM, detailing all discrepancies, non-compliance items, and the proposed corrective action.

Verification: Within five days of the discovery of any discrepancies, the resident engineer shall transmit to the CBO and the CPM a Non-Conformance Report (NCR), and the proposed corrective action for review and approval. Within five days of resolution of the NCR, the project owner shall submit the details of the corrective action to the CBO and the CPM. A list of NCRs, for the reporting month, shall also be included in the following Monthly Compliance Report.

CIVIL-4 After completion of finished grading and erosion and sedimentation control and drainage work, the project owner shall obtain the CBO's approval of the final grading plans (including final changes) for the erosion and sedimentation control work. The civil engineer shall state that the work within

his/her area of responsibility was done in accordance with the final approved plans [2001 CBC, Section 3318, Completion of Work].

Verification: Within 30 days (or project owner and CBO approved alternative timeframe) of the completion of the erosion and sediment control mitigation and drainage work, the project owner shall submit to the CBO, for review and approval, the final grading plans (including final changes) and the responsible civil engineer's signed statement that the installation of the facilities and all erosion control measures were completed in accordance with the final approved combined grading plans, and that the facilities are adequate for their intended purposes, with a copy of the transmittal letter to the CPM. The project owner shall submit a copy of the CBO's approval to the CPM in the next Monthly Compliance Report.

STRUC-1 Prior to the start of any increment of construction of any major structure or component (or project owner and CBO approved alternative timeframe) 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.

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 [2001 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 prior to the start of on-site fabrication and

installation of each structure, equipment support, or foundation [2001 CBC, Section 106.4.2, Retention of plans; and Section 106.3.2, Submittal documents];

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 engineer [2001 CBC, Section 106.3.4, Architect or Engineer of Record]; and

5. Submit to the CBO the responsible engineer's signed statement that the final design plans conform to the applicable LORS [2001 CBC, Section 106.3.4, Architect or Engineer of Record].

Verification: At least 60 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 **Facility Design Table 1** of Condition of Certification **GEN-2** above, the project owner shall submit to the CBO the above final design plans, specifications and calculations, with a copy of the transmittal letter to the CPM.

The project owner shall submit to the CPM, in the next Monthly Compliance Report a copy of a statement from the CBO that the proposed structural plans, specifications and calculations have been approved and are in compliance 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 2001 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 and the proposed corrective action to the CBO, with a copy of the

transmittal letter to the CPM [2001 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 2001 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 to the CBO prior notice of the intended filing.

Verification: On a schedule suitable to the CBO, the project owner shall notify the CBO of the intended filing of design changes, and shall submit the required number of sets of revised drawings and the required number of copies of the other above-mentioned documents to the CBO, with a copy of the transmittal letter to the CPM. The project owner shall notify the CPM, via the Monthly Compliance Report, when the CBO has approved the revised plans.

STRUC-4 Tanks and vessels containing quantities of toxic or hazardous materials exceeding amounts specified in Chapter 3, Table 3-E of the 2001 CBC shall, at a minimum, be designed to comply with the requirements of that Chapter.

Verification: At least 30 days (or project owner and CBO approved alternate 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 **Facility Design 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 [2001 CBC, Section 106.3.2, Submittal Documents; Section 108.3, Inspection Requests; Section 108.4, Approval Required; 2001

California Plumbing Code, Section 103.5.4, Inspection Request; Section 301.1.1, Approval].

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 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 [2001 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 **Facility Design 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 [2001 CBC, Section 108.3, Inspection Requests].

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 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.

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. 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 [2001 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 2001, 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 [2001 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.

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.

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.

C. The following activities shall be reported to the CPM in the Monthly Compliance Report:

1. Receipt or delay of major electrical equipment;
2. Testing or energizing of major electrical equipment; and
3. A signed statement by the registered electrical engineer certifying that the proposed final design plans and specifications conform to requirements set forth in the Energy Commission Decision.

Verification: At least 30 days (or project owner and CBO approved alternative 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

BEP II (Blythe Energy Project Phase II). 2002d. Revised Application for Certification for Blythe II. 07/03/2002 (tn: 26100)

BEP II (Blythe Energy Project Phase II). 2004d. Revision to Section 2.0 of the Blythe Energy Project Phase II. POS. 04/21/2004 (tn: 31295)

BEP II (Blythe Energy Project Phase II). 2004e. Caithness Blythe II Response to the Blythe Energy Phase II Preliminary Staff Assessment. 04/28/2004. (tn: 31327)

GEOLOGY, MINERAL RESOURCES, AND PALEONTOLOGY

Testimony of Patrick A. Pilling, Ph.D., P.E., G.E.

INTRODUCTION

In this section, Energy Commission staff discusses potential impacts of the proposed Blythe Energy Project Phase II (BEP II) regarding geologic hazards, geologic (including mineralogic), and paleontologic resources. Staff's objective is to ensure that there will be no significant adverse impacts to geological and paleontological resources during project construction, operation and closure. A brief geological and paleontological overview of the project is provided. The section concludes with staff's proposed monitoring and mitigation measures with respect to geologic hazards and geologic, mineralogic, and paleontologic resources, with the inclusion of Conditions of Certification.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

The applicable LORS are listed in the Application for Certification (AFC), in Section 3.0, Table 3.0-1 of the AFC (Caithness Blythe II, LLC, 2002). The following is a brief description of the LORS for geologic hazards and resources, and paleontologic resources.

FEDERAL

The proposed BEP II plant site is not located on federal land. As such, there are no federal LORS for geological hazards and resources or grading for the BEP II plant site.

STATE AND LOCAL

The project shall be designed and constructed to the 2001 edition of the California Building Standards Code (CBSC). The CBSC includes a series of standards that are used in project investigation, design and construction (including grading and erosion control).

The "Measures for Assessment and Mitigation of Adverse Impacts to Non-renewable Paleontologic Resources: Standard Procedures" (Society of Vertebrate Paleontology [SVP] 1995) is a set of procedures and standards for assessing and mitigating impacts to vertebrate paleontological resources. The measures were adopted in October 1995 by the Society of Vertebrate Paleontology (SVP), a national organization of professional scientists.

ENVIRONMENTAL SETTING

The proposed BEP II site is located within the Colorado Desert geomorphic province near the Colorado River and the California – Arizona state line. This area within the Colorado Desert is characterized by the flood plain of the Colorado River and numerous flood terraces. The BEP II site is located on the Palo Verde Mesa, a flood terrace of the Colorado River. Major geologic units in the vicinity of the site include Tertiary and pre-

Tertiary igneous, metamorphic, and sedimentary bedrock, Miocene to Pliocene fanglomerate [conglomerate], the Pliocene Bouse Formation, and Quaternary alluvium. The Pliocene to Pleistocene alluvium is also named the Chemehuevi Formation. The Miocene to Pliocene fanglomerate consists of cemented, poorly sorted gravel and sand. The Pliocene Bouse Formation consists of marine and brackish-water limestone and interbedded clays, silts, sands, and tufa (chemical sedimentary rock consisting of calcium carbonate or silica, deposited in solution in the water of a lake). The Quaternary alluvium consists of sands, gravels, silts, and clays.

The plant site has received approximately 200,000 cubic yards of fill, the result of mass grading during Phase I construction. Underlying native materials consist of a mix of light to dark brown, medium dense to dense silty sand to poorly-graded sand to a depth of 111 feet. Information contained in the AFC (Caithness Blythe II, LLC, 2002) indicates ground water is present at a depth approximately 88-1/2 feet below the original ground surface.

ANALYSIS AND IMPACTS

There are two types of impacts considered in this section. The first are geologic hazards, which could impact proper functioning of the proposed facility and include faulting and seismicity, liquefaction, dynamic compaction, hydrocompaction, subsidence, expansive soils, landslides, and tsunamis and seiches. The second considers potential impacts the proposed facility could have on existing geologic, mineralogic, and paleontologic resources in the area.

STAFF'S CRITERIA FOR DETERMINING IMPACT SIGNIFICANCE

No federal LORS with respect to geologic hazards and geologic and mineralogic resources apply to this project; however, the California Building Standards Code (CBSC) provides geotechnical and geological investigation and design guidelines, which engineers must adhere to when designing a proposed facility. As a result, the criteria used to assess geologic hazard impact significance includes evaluating each potential hazard in relation to being able to adequately design and construct the proposed facility.

The California Environmental Quality Act Guidelines Appendix G provides a checklist of questions that a lead agency should normally address if relevant to a project's environmental impacts.

- Section (V) (c) asks if the project will directly or indirectly destroy a unique paleontological resource or site or unique geological feature.
- Sections (VI) (a), (b), (c), (d), and (e) pose questions that are focused on whether or not the project would expose persons or structures to geologic hazards.
- Sections (X) (a) and (b) pose questions about the project's effect on mineral resources.

With respect to impacts, the proposed facility may have on existing geologic and mineralogic resources, geologic and mineral resource maps for the surrounding area have been reviewed, in addition to any site-specific information provided by the

applicant, to determine if geologic and mineralogic resources are present in the area. When available, operating procedures of the proposed facility, in particular ground water extraction and mass grading operations, are reviewed to determine if such operations could adversely impact such resources.

Staff reviewed existing paleontologic information for the surrounding area, as well as any site-specific information provided by the applicant, in accordance with accepted assessment protocol (SVP, 1995) to determine if there are any known paleontologic resources in the general area. If present or likely to exist, Conditions of Certification are applied to project approval, which outlines procedures required during construction to mitigate impacts to potential resources.

GEOLOGIC HAZARDS

The AFC (Caithness Blythe II, LLC, 2002) provides documentation of potential geologic hazards at the BEP II plant site. Review of the AFC, coupled with our independent research, indicates the potential for these geologic hazards to impact the facility is low. Our independent research included review of available geologic maps, reports, and related data of the BEP II plant site and associated alternative linear facility areas. Geological information was available from the California Geological Survey (CGS), U. S. Geological Survey (USGS), and other governmental organizations.

Faulting and Seismicity

Energy Commission staff reviewed the California Geological Survey (CGS) publication *Fault Activity Map of California and Adjacent Areas with Locations and Ages of Recent Volcanic Eruptions*, dated 1994 (CGS, 1994); the *Geologic Map of California – Salton Sea Sheet* (CGS, 1967); the Late Pliocene – Quaternary (Post 4 m.y.) Faults, Folds and Volcanic Rocks in Arizona (Scarborough et al., 1986); the *Geologic Map of Yuma County, Arizona* (Wilson, 1960); the Preliminary Geologic Map of the Blythe 30' by 60' Quadrangle, California and Arizona (Stone, 1990); and the *Maps of Known Active Fault Near-Source Zones in California and Adjacent Parts of Nevada* (International Conference of Building Officials [ICBO], 1998). The project is located within Seismic Zone 3, as delineated on Figure 16-2 of the CBSC. The closest known Holocene (active) faults are the Brawley Fault, Elmore Ranch Fault, and the San Andreas Fault (Southern and Coachella segments), which is the closest to the project and located approximately 61 miles southwest of the plant site. Staff has calculated an estimated deterministic peak horizontal ground acceleration for the Brawley Fault, Elmore Ranch fault, and the Southern and Coachella segments of the San Andreas Fault as 0.05 times the acceleration due to gravity (g), 0.05g, 0.08g, and 0.08g, respectively. These estimates are based on a moment magnitude 6.5, 6.6, 7.4, and 7.4 earthquake on the Brawley Fault, Elmore Ranch fault, and the Southern and Coachella segments of the San Andreas Fault, respectively.

Liquefaction

Liquefaction is a nearly complete loss of soil shear strength that can occur during a seismic event. During the seismic event, cyclic shear stresses cause the development of excessive pore water pressure between the soil grains, effectively reducing the

internal strength of the soil. This phenomenon is generally limited to unconsolidated, clean to silty sand (up to 35 percent non-plastic fines) and very soft silts lying below the ground water table. The higher the ground acceleration caused by a seismic event, the more likely liquefaction is to occur. Severe liquefaction can result in catastrophic settlements of overlying structural improvements and lateral spreading of the liquefied layer when confined vertically but not horizontally.

As reported in the AFC (Caithness Blythe II, LLC, 2002), ground water was encountered during exploration at a depth approximately 88-1/2 feet below the ground surface at the plant site. Soils encountered during this exploration generally consist of medium dense to dense silty sand. With a water table greater than 50 feet in depth, there is no potential for liquefaction.

Dynamic Compaction

Dynamic compaction of soils results when relatively unconsolidated granular materials experience vibration associated with seismic events. The vibration causes a decrease in soil volume, as the soil grains tend to rearrange into a more dense state (an increase in soil density). The decrease in volume can result in settlement of overlying structural improvements. Since the plant site is generally underlain by medium dense to dense silty sand, the potential for dynamic compaction at the plant site is considered by staff to be low.

Hydrocompaction

Partially saturated soils can possess bonds that are a result of chemical precipitates that accumulate under semi-arid conditions. Such soluble compound bonds provide the soils with cohesion and rigidity; however, these bonds can be destroyed upon prolonged submergence. When destroyed, a substantial decrease in the material's void ratio is experienced even though the vertical pressure does not change. Materials that exhibit this decrease in void ratio and corresponding decrease in volume with the addition of water are defined as collapsible soils. Collapsible soils are typically limited to true loess, clayey loose sands, loose sands cemented by soluble salts, and windblown silts. Since the plant site is generally underlain by medium dense to dense silty sand, the potential for hydrocompaction at the plant site is considered by staff to be low.

Subsidence

Ground subsidence is typically caused when ground water is drawn down by irrigation activities such that the effective unit weight of the soil mass is increased, which in turn increases the effective stress on underlying soils, resulting in consolidation/settlement of the underlying soils. The BEP II will obtain ground water from wells located at the plant site with drawdowns estimated to be less than 4 feet; as such, significant draw down of the water table due to BEP II operations is not anticipated. As a result, the potential for ground subsidence is considered by staff to be low.

Expansive Soils

Soil expansion occurs when clay-rich soils, with an affinity for water, exist in-place at a moisture content below their plastic limit. The addition of moisture from irrigation, capillary tension, water line breaks, etc. causes the clay soils to collect water molecules

in their structure, which, in turn, causes an increase in the overall volume of the soil. This increase in volume can correspond to movement of overlying structural improvements. As reported in the exploration logs, materials encountered in the project area consist of silty sand soils. As a result, the potential for expansive soils is low.

Landslides

Landslides typically involve rotational slump failures within surficial soils/colluvium and/or weakened bedrock that are usually implemented by an increase of the material's moisture content above a layer, which exhibits a relatively low strength. Debris-flows are shallow landslides that travel downslope very rapidly as muddy slurry. The BEP II site is relatively flat with up to approximately 25 feet of relief over the plant site and lies approximately 1 mile east of the edge of the Palo Verde Mesa. As a result, the potential impact of landslides to the BEP II site is low. There is some potential for a debris-flow driven by a flash flood; however, the flash flood would be caused by an unusually intense thunderstorm, which would be a low probability event.

Tsunamis and Seiches

Tsunamis and seiches are earthquake-induced waves, which inundate low-lying areas adjacent to large bodies of water. The proposed site is situated approximately 350 to 375 feet above mean sea level and no large bodies of water are present near the BEP II site. As a result, the potential for tsunamis and seiches to affect the site is considered by staff to be negligible.

GEOLOGIC, MINERALOGIC, AND PALEONTOLOGIC RESOURCES

Energy Commission staff have reviewed applicable geologic maps and reports for this area (Kohler-Anatablin, 1994; Clark, 1969; Larose, 1999; DOGGR, 1982; Saul et al., 1968; and CGS, 1980). Based on this information and the information contained in the AFC (Caithness Blythe II, LLC, 2002), there are no known mineralogic resources located at or immediately adjacent to the proposed BEP II site. An area of undeveloped warm thermal waters and several thermal wells are present in the Palo Verde Valley to the east (CGS, 1980). No other geologic resources are located at or immediately adjacent to the proposed BEP II site.

The applicant's consultant conducted a paleontologic resources field survey and a sensitivity analysis for the BEP I and BEP II plant sites. No significant fossil fragments were observed at the BEP II site; however, two vertebrate fossils were identified during construction of the BEP I project over five months of near-full-time monitoring. Surficial, older alluvium of the Chemehuevi Formation has been assigned a "high" sensitivity rating with respect to potentially containing paleontological resources. Based on this information and staff's review of available information (San Bernardino County Museum, 2002), the proposed BEP II site has a high potential to contain significant paleontologic resources.

PROJECT SPECIFIC IMPACTS

Seismicity represents the main geologic hazard at this site. Mass grading performed during construction of Blythe I resulted in the placement of approximately 200,000 cubic yards of fill within the limits of Blythe II. If this material was not placed as a structural fill,

which requires testing and inspection, reworking of this material would be necessary. **Conditions of Certification GEN-1**, **GEN-5**, **CIVIL-1 in the Facility Design** section, however, requires such work and should mitigate any potential impact, as well as those from seismicity, to a level of less than significant. No geologic or mineralogic resources are known to exist in the area. Paleontologic resources have been identified during construction of the BEP I plant, and the (confidential) Paleontologic Resources Report (Caithness Blythe II, LLC, 2002) assigns a sensitivity rating of high for the older alluvium that underlies the proposed facility. Since the proposed project will include significant amounts of trenching and grading and a few fossils have been discovered at the adjacent BEP I plant site, staff considers the probability that paleontologic resources will be encountered during trenching and possibly mass grading of undisturbed areas at the BEP II site to be high based on SVP assessment criteria. Conditions of Certification **PAL-1** to **PAL-7** are designed to mitigate any paleontological resource impacts, as discussed above, to a less than significant level.

CUMULATIVE IMPACTS

The BEP II site lies in an area that exhibits low geologic hazards and no known geologic or mineralogic resources. However, construction and operation of the BEP II project will likely require either a new 118-mile electrical transmission line linking a new substation near the BEP I site with the Southern California Edison Company's Devers Substation, located near Palm Springs, California or an approximately 60-mile-long transmission line currently proposed by BEP I.

The Bureau of Land Management (BLM) has recommended a specific measure to mitigate paleontological impacts associated with the transmission line over federally administered land. The mitigation measure requires that a paleontologist develop a mitigation program. This measure is consistent with the Conditions of Certification recommended herein for this portion of the project. Based on this information and the proposed Conditions of Certification to mitigate potential project specific impacts, it is staff's opinion that the potential for significant adverse cumulative impacts to the project from geologic hazards, and to potential geologic, mineralogic, and paleontologic resources from the proposed project is low.

RESPONSE TO COMMENTS ON PSA

Minor comments on the PSA were also received from Western Area Power Authority and the report text was updated, where deemed appropriate.

The Applicant issued three comments with respect to Geology, Mineral Resources, and Paleontology. Comments one and two were related to an alternative water supply line, initially considered, that has been subsequently removed from the project. Water supply for the project will be provided by two (2) on-site ground water wells as described previously. The third and final comment was that a significant amount of grading (filling) has already been performed across the site, and that minimal disturbance of additional areas is anticipated during construction of Blythe II. However, trenching will still be necessary and will encounter native materials such that there is still the potential to encounter paleontological resources.

FACILITY CLOSURE

A definition and general approach to closure is presented in the **General Conditions** section of this assessment. Facility closure activities are not anticipated to impact geologic, mineralogic, or paleontologic resources. This is due to the fact that no such resources are known to exist at the proposed project site. In addition, decommissioning and closure of the power plant should not negatively affect geologic, mineralogic, or paleontologic resources since the majority of the ground disturbed in plant decommissioning and closure will have been disturbed during construction and operation of the facility.

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. Paleontological **Conditions of Certification PAL-1 through PAL-7** are identified below.

PAL-1 The project owner shall provide the Compliance Project Manager (CPM) with the resume and qualifications of its Paleontological Resource Specialist (PRS) for review and approval. If the approved PRS is replaced prior to completion of project mitigation and submittal of the Paleontological Resources Report, the project owner shall obtain CPM approval of the replacement PRS. The project owner shall submit to the CPM to keep on file, resumes of the qualified Paleontological Resource Monitors (PRMs). If a PRM is replaced, the resumes of the replacement PRM shall also be provided to the CPM.

The PRS resume shall include the names and phone numbers of references. The resume shall also demonstrate to the satisfaction of the CPM, the appropriate education and experience to accomplish the required paleontological resource tasks.

As determined by the CPM, the PRS shall meet the minimum qualifications for a vertebrate paleontologist as described in the Society of Vertebrate Paleontology (SVP) guidelines of 1995. The experience of the PRS shall include the following:

1. Institutional affiliations, appropriate credentials and college degree;
2. ability to recognize and collect fossils in the field;
3. local geological and biostratigraphic expertise;
4. proficiency in identifying vertebrate and invertebrate fossils and;
   at least three years of paleontological resource mitigation and field experience in California, and at least one year of experience leading paleontological resource mitigation and field activities.

The project owner shall ensure that the PRS obtains qualified paleontological resource monitors to oversee and evaluate project operations as he or she deems necessary. Paleontologic resource monitors (PRMs) shall have the equivalent of the following qualifications:

- BS or BA degree in geology or paleontology and one year experience monitoring in California; or
- AS or AA in geology, paleontology or biology and four years experience monitoring in California; or
- Enrollment in upper division classes pursuing a degree in the fields of geology or paleontology and two years of monitoring experience in California.

Verification: (1) At least 60 days prior to the start of ground disturbance, the project owner shall submit a resume and statement of availability of its designated PRS for on-site work.

(2) At least 20 days prior to ground disturbance, the PRS or project owner shall provide a letter with resumes naming anticipated monitors for the project 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. The letter shall be provided to the CPM no later than one week prior to the monitor beginning on-site duties.

(3) Prior to the termination or release of a PRS, the project owner shall submit the resume of the proposed new PRS to the CPM for review and approval.

PAL-2 The project owner shall provide to the PRS and the CPM, for approval, maps and drawings showing the footprint of the power plant, construction laydown areas, and all related facilities. Maps shall identify all areas of the project where ground disturbance is anticipated. If the PRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the PRS and CPM. The site grading plan and the plan and profile drawings for the utility lines would be acceptable for this purpose. The plan drawings shall show the location, depth, and extent of all ground disturbances and should be of such as scale to allow the PRS to determine and map fossil occurrences. 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 project owner shall ensure that the PRS or PRM consults weekly with the project superintendent or construction field manager to confirm area(s) to be worked during the next week, until ground disturbance is completed.

Verification: (1) At least 30 days prior to the start of ground disturbance, the project owner shall provide the maps and drawings to the PRS and CPM.

(2) If there are changes to the footprint of the project, revised maps and drawings shall be provided to the PRS and CPM at least 15 days prior to the start of ground disturbance.

(3) If there are changes to the scheduling of the construction phases, the project owner shall submit a letter to the CPM within 5 days of identifying the changes.

PAL-3 The project owner shall ensure that the PRS prepares, and the project owner submits to the CPM for review and approval, a Paleontological Resources Monitoring and Mitigation Plan (PRMMP) to identify general and specific measures to minimize potential impacts to significant paleontological resources. Approval of the PRMMP by the CPM shall occur prior to any ground disturbance. The PRMMP shall function as the formal guide for monitoring, collecting and sampling activities and may be modified with CPM approval. This document shall be used as 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 Vertebrate Paleontology (SVP, 1995) and shall include, but not be limited to, the following:

1. Assurance that the performance and sequence of project-related tasks, such as any literature searches, pre-construction surveys, worker environmental training, fieldwork, flagging or staking; construction monitoring; mapping and data recovery; fossil preparation and collection; identification and inventory; preparation of final reports; and transmittal of materials for curation will be performed according to the PRMMP procedures;
2. Identification of the person(s) expected to assist with each of the tasks identified within the PRMMP and the Conditions of Certification;
3. A thorough discussion of the anticipated geologic units expected to be encountered, the location and depth of the units relative to the project when known, and the known sensitivity of those units based on the occurrence of fossils either in that unit or in correlative units;
4. A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed schedule for the monitoring and sampling;
5. A discussion of the procedures to be followed in the event of a significant fossil discovery, halting construction, resuming construction, and how notifications will be performed;
6. A discussion of equipment and supplies necessary for collection of fossil materials and any specialized equipment needed to prepare, remove, load, transport, and analyze large-sized fossils or extensive fossil deposits;
7. 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 Paleontology standards and requirements for the curation of paleontological resources;

8. Identification of the institution that has agreed to receive any data and fossil materials collected, requirements or specifications for materials delivered for curation and how they will be met, and the name and phone number of the contact person at the institution; and
9. A copy of the paleontological Conditions of Certification.

Verification: At least (30) days prior to ground disturbance, the project owner shall provide two copies of the PRMMP to the CPM. The PRMMP shall include an affidavit of authorship by the PRS, and acceptance of the PRMMP by the project owner evidenced by a signature.

PAL-4 Prior to ground disturbance and for the duration of construction, the project owner and the PRS shall prepare and conduct weekly CPM-approved training for all recently employed project managers, construction supervisors and workers who are involved with or operate ground disturbing equipment or tools and who have not previously had the training. Workers shall not excavate in sensitive units prior to receiving CPM-approved worker training. Worker training shall consist of an initial in-person PRS training during the project kick-off for those mentioned above. Following initial training, a CPM-approved video or in-person training may be used for new employees. The training program may be combined with other training programs prepared for cultural and biological resources, hazardous materials, or 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.

The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Good quality photographs or physical examples of vertebrate fossils shall be provided for project sites containing units of high sensitivity;
3. Information that the PRS or PRM has the authority to halt or redirect construction in the event of a discovery or unanticipated impact to a paleontological resource;
4. Instruction that employees are to halt or redirect work in the vicinity of a find and to contact their supervisor and the PRS or PRM;
5. An informational brochure that identifies reporting procedures in the event of a discovery;
6. A 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: (1) At least 30 days prior to ground disturbance, the project owner shall submit two copies of the proposed WEAP including the brochure with the set of reporting procedures the workers are to follow.

(2) 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.

(3) If an alternate paleontological trainer is requested by the project owner, the resume and qualifications of the trainer shall be submitted to the CPM for review and approval prior to installation of the alternate trainer. Alternate trainers shall not conduct training prior to CPM authorization.

(4) In the Monthly Compliance Report (MCR) the project owner shall provide copies of the WEAP Certification of Completion forms with the names of those trained and the trainer or type of training offered that month. The MCR shall also include a running total of all persons who have completed the training to date.

PAL-5 The project owner shall ensure that the PRS and PRM(s) monitor consistently 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 project owner shall notify and seek the concurrence of the CPM.

The project owner shall ensure that the PRS and PRM(s) have the authority to halt or redirect construction if paleontological resources are encountered. The project owner shall ensure that there is no interference with monitoring activities unless directed by the PRS. Monitoring activities shall be conducted as follows:

1. Any change of monitoring different from the accepted program presented in the PRMMP shall be proposed in a letter or email from the PRS and the project owner to the CPM prior to the change in monitoring. The letter or email shall include the justification for the change in monitoring and be submitted to the CPM for review and approval.

2. The project owner shall ensure that the PRM(s) keeps 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 project owner shall ensure that the PRS immediately notifies 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 project owner shall ensure that the PRS prepares a summary of the monitoring and other paleontological activities that will be placed in the Monthly Compliance Reports (MCR). The summary will include the name(s) of PRS or PRM(s) active during the month, general descriptions of training and monitored construction activities and general locations of excavations, grading, etc. A section of the report shall include the geologic units or subunits encountered; descriptions of sampling within each unit; and a list of identified fossils. A final section of the report shall 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 report shall include an explanation in the summary as to why monitoring was not conducted.

Verification: The project owner shall ensure that the PRS submits the summary of monitoring and paleontological activities in the MCR. When feasible, the CPM shall be notified 10 days in advance of any proposed changes in monitoring different from the plan identified in the PRMMP. If there is any unforeseen change in monitoring, the notice shall be given as soon as possible prior to implementation of the change.

PAL-6 The project owner, through the designated PRS, shall ensure that all components of the PRMMP are adequately performed including collection of fossil materials, preparation of fossil materials for analysis, analysis of fossils, identification and inventory of fossils, the preparation of fossils for curation, and the delivery for curation of all significant paleontological resource materials encountered and collected during the project construction.

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 Paleontological Resource Report (See **PAL-7**). A signed contract or agreement with the PRS shall be provided to the CPM upon request. The project owner shall be responsible to pay any curation fees charged by the museum for fossils collected and curated as a result of paleontological mitigation. A copy of the letter of transmittal submitting the fossils to the curating institution shall be provided to the CPM.

PAL-7 The project owner shall ensure preparation of a Paleontological Resources Report (PRR) by the designated PRS. The PRR shall be prepared following completion of the ground disturbing activities. The PRR shall include an analysis of the collected fossil materials and related information and submitted to the CPM for review and approval.

The report shall include, but is not limited to, a description and inventory of recovered fossil materials; a map showing the location of paleontological resources encountered; determinations of sensitivity and significance; and a statement by the PRS that project impacts to paleontological resources have been mitigated.

Verification: Within (90) days after completion of ground disturbing activities, including landscaping, the project owner shall submit the Paleontological Resources Report under confidential cover to the CPM.

Certification of Completion of Worker
Environmental Awareness Program
BLYTHE ENERGY PROJECT II (02-AFC-1)

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 and Biological 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 the Monthly Compliance Report.

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Cul Trainer: _____ Signature:_____ Date: ___/___/____
PaleoTrainer: _____ Signature:_____ Date: ___/___/____
Bio Trainer: _____ Signature:_____ Date: ___/___/____

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POWER PLANT EFFICIENCY

Testimony of Kevin Robinson and Steve Baker

INTRODUCTION

The Energy Commission makes findings as to whether energy use by the Blythe Energy Project Phase II (BEP II) 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 BEP II'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 impact. 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:

- examine whether the facility will likely present any adverse impacts upon energy resources;
- examine whether these adverse impacts are significant; and if so,
- examine 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 LORS apply to the efficiency of this project.

STATE

No State LORS apply to the efficiency of this project.

LOCAL

No local or county ordinances apply to power plant efficiency.

SETTING

Caithness Blythe II proposes to construct and operate the 520 MW (nominal gross output) combined cycle, merchant BEP II power plant to generate baseload and load following power, selling energy to the power market (Blythe 2002d, AFC §§ 8.3.2, 8.4, Blythe 2004d, AFC §§ 1.1, 2.1, 2.2.2, 2.2.16.1). (Note that this nominal rating is based upon preliminary design information and generating equipment manufacturers' guarantees. The project's actual maximum generating capacity may differ from this figure.) The BEP II will consist of two Siemens Westinghouse V84.3a 170 MW F-class combustion gas turbines with a chilled water inlet air cooling system or an evaporative inlet air cooling system (Blythe 2004d, AFC §§ 2.1, 2.2.2, 2.2.4.1.1), two multi-pressure heat recovery steam generators (HRSGs) with duct burners, and one single 3-pressure, reheat, condensing steam turbine (ST) generator producing a maximum of 180 MW,

arranged in a two-on-one combined cycle train, totaling approximately 520 MW. The gas turbines and HRSGs will be equipped with dry low-NOx combustors and selective catalytic reduction to control air emissions (Blythe 2004b, AFC §§ 1.1.1, 2.2.2, 2.2.12). Natural gas will be delivered by the existing El Paso Natural Gas Company (EPNGC) gas distribution system through a new pipeline connection to the completed Blythe Energy Project I gas supply system (Blythe 2002d, AFC §§ 6.4, 8.3.1, Blythe 2004d, AFC §§ 1.1.1, 2.2.7, Fig. 2.0-4).

ANALYSIS AND IMPACTS

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).

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. Under normal conditions, the BEP II will burn natural gas at a nominal rate of 84,400 MMBtu per day, lower heating value (LHV) (Blythe 2004d, AFC § 2.2.7). 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 full load efficiency of between approximately 55 and 58 percent LHV (Blythe 2002d, AFC § 8.4, Figures 2.0-6A, Figure 2.0-6B, Figure 2.0-6C, Figure 2.0-6D). This efficiency level compares favorably to the average fuel efficiency of a typical 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 (Blythe 2002d, AFC § 8.3.1, Blythe 2004d, AFC §§ 1.1.1, 2.2.7). Natural gas for the BEP II will be supplied from the existing EPNGC system via a new pipeline connection to the approved BEP I gas supply system. The EPNGC system is capable of delivering the

required quantity of gas to the BEP II. The El Paso natural gas supply represents a reliable source of natural gas for this project. 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 the EPNGC via a new pipeline connection to the approved BEP I gas supply system (Blythe 2002d, AFC § 8.3.1, Blythe 2004d, AFC §§ 1.1.1, 2.2.7). There is no real likelihood that the BEP II will require the development of additional energy supply capacity.

Compliance With Energy Standards

No standards apply to the efficiency of the BEP II or other non-cogeneration projects.

Alternatives To Reduce Wasteful, Inefficient And Unnecessary Energy Consumption

The BEP II 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 BEP II will be configured as a combined cycle power plant, in which electricity is generated by two gas turbines, and additionally by a reheat steam turbine that operates on heat energy recuperated from the gas turbines' exhaust (Blythe 2004d, AFC §§ 1.1, 1.1.1, 2.1, 2.2.2). 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.

The Applicant proposes to use inlet air coolers, HRSG duct burners (re-heaters), three-pressure HRSGs and a steam turbine unit and circulating cooling water system (Blythe 2004d, AFC §§ 1.1, 1.1.1, 2.1, 2.2.2, 2.2.4.1.1, 2.2.4.2, 2.2.4.3). Staff believes these features contribute to meaningful efficiency enhancement to the BEP II. The two-train combustion turbine (CT)/HRSG configuration also allows for high efficiency during unit turndown because one CT can be shut down, leaving one fully loaded, efficiently operating CT instead of having two CTs operating at an inefficient 50 percent load.

The BEP II includes HRSG duct burners, partially to replace heat to the ST cycle during high ambient temperatures when CT capacity drops, and partially for added power. Duct firing also provides a number of operational benefits, such as load following and balancing and optimizing the operation of the ST cycle.

Equipment Selection

The F-class of advanced gas turbines to be employed in the BEP II represent some of the most modern and efficient such machines now available. The applicant will employ two Siemens-Westinghouse V84.3a advanced F-class combustion gas turbine generators in a two-on-one combined cycle power train nominally rated at 520 MW and 58 percent efficiency LHV (Blythe 2002d, AFC § 8.4, Blythe 2004d, AFC §§ 1.1, 1.1.1, 2.1, 2.2.2, 2.2.4.1.1).

One possible alternative is the Siemens-Westinghouse 501F, nominally rated in a two-on-one train combined cycle configuration at 589.7 MW and 57.2 percent efficiency LHV at ISO conditions (GTW 2004).

Another alternative is the General Electric GE 7FA, nominally rated in a two-on-one train combined cycle configuration at 529.9 MW and 56.5 percent efficiency LHV (GTW 2004).

Any differences among the V84.3a, GE 7FA, and W501FD in actual operating efficiency will be insignificant. Selecting among these machines is thus based on other factors, such as generating capacity, cost, commercial availability, and ability to meet air pollution limitations.

Efficiency Of Alternatives To The Project

The project objectives include generation of baseload electricity and ancillary services, as market conditions dictate (Blythe 2002d, AFC §§ 6.7, 8.3.2, 8.4, Blythe 2004d, AFC §§ 1.1, 2.2.2, 2.2.16.1, 2.4.1).

Alternative Generating Technologies

Alternative generating technologies for the BEP II are considered in the AFC (Blythe 2002d, AFC § 6.7.2, Table 6.0-3, Table 6.0-4). Fossil fuels, nuclear, solar, hydroelectric, and biomass technologies are all considered. Given the project objectives, location, and air pollution control requirements, staff agrees with the applicant that only natural gas-burning technologies are feasible.

Natural Gas-Burning Technologies

Fuel consumption is one of the most important economic factors in selecting an electric generator; fuel typically accounts for over two-thirds of the total operating costs of a fossil-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 thus strongly motivated to purchase fuel-efficient machinery.

Modern gas turbines embody the most fuel-efficient electric generating technology available today. Currently available, large combustion turbine models can be grouped into three categories including conventional, advanced, and next generation. Advanced combustion turbines offer advantages for the BEP II. Their higher firing temperatures 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 (Blythe 2004d, AFC §§ 1.1.1, 2.2.2, 2.2.12.1).

One possible alternative to an advanced F-class gas turbine is the next generation G-class machine, such as the Siemens-Westinghouse 501G gas turbine generator, which employs partial steam cooling to allow slightly higher temperatures, yielding slightly greater efficiency. In actual operation, one would expect to see the difference in efficiency narrow, as the larger capacity G-class turbines would run at less than optimum (full) output more frequently than the smaller capacity F-class turbines. (Gas turbine efficiency drops rapidly at less then full load.) The W501G is still relatively new; the first such machine began simple cycle operation at a site in Florida owned by Lakeland Electric and Water on April 16, 2001 and at PG&E Generating's Millennium combined cycle project in Charlton, Massachusetts on April 5, 2001 (GTW 2001). Given the minor efficiency improvement promised by the G-class turbine and the lack of a proven track record for the W501G, the applicant's decision to purchase F-class machines is a reasonable one.

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.

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.

Given the climate at the project site and the relative lack of clear superiority of one system over the other, staff agrees that either choice of gas turbine inlet air cooling methods will yield no significant adverse energy impacts.

Conclusions on Efficiency of Alternatives

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. The two-train CT/HRSG configuration also allows for high efficiency during unit turndown because one CT can be shut down, leaving one fully loaded, efficiently operating CT instead of having two CTs operating at an inefficient 50 percent load. This offers an efficiency advantage over the larger machines during unit turndown. There are no alternatives that could significantly reduce energy consumption.

Staff, therefore, believes the BEP II will not constitute a significant adverse impact on energy resources.

CUMULATIVE IMPACTS

BEP I presently operates a nearby power plant project that holds the potential for cumulative energy consumption impacts when aggregated with the project. Staff knows of no other projects that could result in cumulative energy impacts.

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 BEP II. 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. The high efficiency of the proposed BEP II 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 adversely impacting or even reducing the cumulative amount of natural gas consumed for power generation.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The project, if constructed and operated as proposed, would generate a nominal 520 MW of electric power at an overall project fuel efficiency between 55 and 58 percent LHV. While it will consume substantial amounts of energy, it will do so in the most efficient manner practicable. It will not create significant adverse effects on energy supplies or resources, will not require additional sources of energy supply, and will not consume energy in a wasteful or inefficient manner. No energy standards apply to the project. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources.

No cumulative impacts on energy resources are likely. Facility closure would not likely present significant impacts on electric system efficiency.

RECOMMENDATION

No Conditions of Certification are proposed.

REFERENCES

BEP II (Blythe Energy Project Phase II). 2002d. Revised Application for Certification for Blythe II. 07/03/2002 (tn: 26100)

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POWER PLANT RELIABILITY

Testimony of Kevin Robinson 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 Caithness Blythe II has predicted a 92 to 98 percent availability for the Blythe Energy Project Phase II (see below), staff uses the benchmark identified above, rather than Caithness Blythe II'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 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 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 Cal-ISO 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. 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.

Caithness Blythe II proposes to operate the 520 MW (nominal output) Blythe Energy Project Phase II (BEP II), selling energy and capacity to the power market (Blythe 2002d, AFC § 8.4, Blythe 2004d, AFC §§ 1.1, 2.1, 2.2.16.1). The project is expected to operate at an overall availability in the range of 92 to 98 percent (Blythe 2002d, AFC § 8.3.2), and at a capacity factor, over the life of the plant, of 30-100 percent of base load (Blythe 2004d, AFC § 2.4.1).

ANALYSIS AND IMPACTS

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 (Blythe 2002d, AFC §

8.3.2, Blythe 2004d, AFC § 2.4.1), the BEP II 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 BEP II 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

Caithness Blythe II describes a QA/QC program (Blythe 2002d, AFC § 8.3.2, Blythe 2004d, AFC §§ 2.4, 2.4.1) typical of the power industry. Equipment will be purchased from qualified suppliers, based on technical and commercial evaluations. Suppliers' personnel, production capability, past performance, QA programs and quality history will be evaluated. 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.

Caithness Blythe II plans to provide appropriate redundancy of function for the combined cycle portion of the project (Blythe 2002d, AFC § 8.3.4, Blythe 2004d, AFC §§ 2.2.6, 2.4.2). The fact that the project consists of two trains of gas turbine generators/HRSGs provides inherent reliability. Failure of a non-redundant component of one train should not cause the other train 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. Emergency direct current (DC) and alternating current (AC) power systems will be supplied by redundant batteries, chargers, and inverters. Other balance of plant equipment will be provided with redundant examples, including:

- three 50 percent capacity feedwater pumps;
- three 50 percent capacity condensate pumps;
- two 60 percent capacity circulating water pumps;

- two 100 percent capacity cooling water pumps; and
- two 100 percent capacity air compressors.

With this opportunity for continued operation in the face of equipment failure, staff believes that equipment redundancy will be sufficient for a project such as this.

Maintenance Program

Caithness Blythe II proposes to establish a preventive plant maintenance program typical of the industry (Blythe 2004d, AFC § 2.4.1). Equipment manufacturers provide maintenance recommendations with their products; the applicant will base its maintenance program on these recommendations. 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 BEP II will burn natural gas from the El Paso Natural Gas Company (EPNGC) distribution system. Gas will be transmitted to the plant via a new pipeline connection to the approved BEP I gas supply system (Blythe 2002d, AFC § 8.3.1, Blythe 2004d, AFC §§ 1.1.1, 2.2.7, 6.4, Figure 2.0-4). This EPNGC natural gas system represents a reliable source of considerable capacity. This system offers access to adequate supplies of gas (Blythe 2002d, AFC § 8.3.1). 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 BEP II will obtain water from two additional wells constructed on-site which will supply cooling water for the steam turbine condenser and inlet air cooling system (Blythe 2004d, AFC §§ 1.5, 2.2.8, 2.2.8.2). The applicant predicts average water consumption of approximately 2,200 gallons per minute (gpm). Potable water will be provided by the water treatment system (Blythe 2004d, AFC §§ 2.2.8, 2.2.8.1, 2.2.8.5.2, Table 2.0-1, Table 2.0-2). Staff believes these sources yield sufficient likelihood of a reliable supply of water. (For further discussion of water supply, see the **Soil and Water Resources** section of this document.)

POWER PLANT RELIABILITY IN RELATION TO NATURAL HAZARDS

Natural forces can threaten the reliable operation of a power plant. High winds, flooding, tsunamis (tidal waves), and seiches (waves in inland bodies of water) will not likely represent a hazard for this project, but seismic shaking (earthquake) presents a credible threat to reliable operation.

Seismic Shaking

The site lies within Seismic Zone 3 (Blythe 2002d, AFC §§ 7.16, 8.1.1, 8.1.2, Blythe 2004d, AFC § 2.3.1); see that portion of this document entitled **Geology, Mineral Resources, and Paleontology**. The project will be designed and constructed to the latest appropriate LORS (Blythe 2002d, AFC §§ 8.1.2, Appendix 8.0, Blythe 2004d, AFC § 2.3.1). 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 that 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 special concern with power plant functional reliability affecting 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 statistic for the years 1999 through 2003 (NERC 2005):

For Combined Cycle units (All MW sizes)
Availability Factor = 89.00 percent

The 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. The applicant's prediction of an annual availability factor in the 92 to 98 percent range (Blythe 2002d, AFC § 8.3.2) 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 two parallel gas turbine generating trains, 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, and staff believes they are likely to yield an adequately reliable plant.

FACILITY CLOSURE

Closure of the facility, whether planned or unplanned, will not impact power plant reliability. Reliability impacts on the electric system from facility closure, should there be

any, are discussed in the **Transmission System Engineering** section of this document.

CONCLUSION

Caithness Blythe II predicts an equivalent availability factor in the 92 to 98 percent range, which staff believes is achievable in light of the industry norm of 90.31 percent for this type of plant. Based on a review of the proposal, 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.

REFERENCES

BEP II (Blythe Energy Project Phase II). 2002d. Revised Application for Certification for Blythe II. 07/03/2002 (tn: 26100)

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TRANSMISSION SYSTEM ENGINEERING

Testimony of Ajoy Guha, MSEE, PE and Al McCuen

SUMMARY OF CONCLUSIONS

Staff has been unable to complete a full analysis of the BEP II applicant's proposal for transmission interconnection due to the following factors:

1. **Existing Transmission Studies are Inaccurate and Incomplete**. The applicant is relying on the 2002-2003 Blythe Area Regional Transmission (BART) study, which it provided as a screening and feasibility study, instead of a System Impact Study for transmission interconnection of the Blythe II project (BEP II). The BART Study is not based on a current, accurate project description, and staff has substantial concerns about the validity of the study. In addition, this FSA documents concerns about the lack of adequate System Impact Studies, the improper consideration of pending projects in the transmission planning queue, and lack of consideration of projects currently being evaluated in the regional transmission planning stakeholder groups including the Devers-Palo Verde No. 2 (DPV2) 500 kV Project and the Blythe Energy Project Transmission Line (BEPTL) modification plan.

2. **Project Description is Uncertain and Unidentified.** While the BART Study concluded that the Desert Southwest Transmission Project (DSWTP) 500 kV line would be the preferred transmission option to transmit the output of BEP II from Western's Buck Boulevard Substation to the California Independent System Operator (CA ISO) grid, there is substantial uncertainty surrounding the DSWTP. First, publication of the final EIS/EIR for the DSWTP line has been deferred for an indefinite period for unknown reasons. Second, staff is uncertain of the applicant's continuing commitment to interconnection with the Western system at the Buck Boulevard Substation and the DSWTP (as proposed before the Commission), given its recent application to the Southern California Edison (SCE) for study of other interconnection alternatives to the CA ISO grid (CA ISO, 2005). This ambiguity results so far in an incomplete and flawed project description, and leaves questions about the feasibility of the project as proposed and its actual transmission option. However, Western has recently initiated a System Impact Study on behalf of the applicant for termination of the BEP II project at Western's Buck Boulevard Substation with the DSWTP transmission option. This study will include the Blythe Energy Project Transmission Line (BEPTL) plan, proposed amendment to the existing Blythe Energy Project Phase I (BEP I) Transmission Line, as a pre-project scenario (Western, 2005). Staff does not know when SCE will commence their interconnection study.

3. **Conformance with Laws, Ordinances, Regulations and Standards (LORS)** cannot be determined from an *engineering* perspective or from a *reliability* perspective with available information, nor can the "whole of the action" per the California Environmental Quality Act (CEQA) be identified because the project interconnection facilities and the transmission option are unidentified, uncertain and infeasible at this stage.

With the available information, staff cannot identify the direct or cumulative system reliability and environmental impacts. For the reasons cited above and explained further below, staff recommends that the Commission not consider approval of the BEP II project until the required critical information identified at the end of this section is provided.

INTRODUCTION

This Transmission System Engineering (TSE) analysis examines whether or not the transmission facilities associated with the proposed project conform to all applicable LORS required for safe and reliable electric power transmission and whether or not the applicant has accurately identified all interconnection facilities required for connection of the project to the electric grid. A definition of technical terms is provided in the TSE Attachment 2, at the end of this section.

Staff's analysis evaluates the power plant switchyard, outlet line, termination and downstream facilities identified by the applicant, CA ISO, Western and the staff. Staff's analysis would normally provide proposed conditions of certification to ensure that the project complies with applicable LORS during the design review, construction, operation and potential closure of the project. However, the project facilities proposed by the applicant are undefined and infeasible given that the BEPTL modification plan[1] is ahead in the generation/transmission queue[2] (CA ISO, 2003a), making the identification of conditions of certification practically questionable.

Unlike other applications for certification, since the Western system is not a part of the CA ISO grid, the CA ISO is not responsible for the BEP II generator interconnection to the Western System (Buck Boulevard Substation). The staff, therefore, has the increased responsibility to evaluate the system reliability impacts of the project and provide conclusions and recommendations to the Commission. However, the CA ISO is still responsible for making sure that there are no adverse impacts on the CA ISO grid due to interconnecting the BEP II generation project to the Western system. At this time without a SIS that has the queue projects properly modeled by the transmission owner (TO), the CA ISO cannot provide a review and conclusions.

Furthermore, under CEQA, the Energy Commission must conduct an environmental review of the "whole of the action," which may include facilities not licensed by the Energy Commission (California Code of Regulations, tit 14, §15378). Therefore, the Energy Commission must identify and evaluate the environmental effects of construction and operation of any new or modified transmission facilities required for the

[1] The BEPTL modification plan was filed by Blythe Energy on October 12, 2004, as a petition to amend the Blythe Energy project to build transmission modifications from the Buck Boulevard Substation as follows: a) a 67.4 mile single circuit 230 kV line from the Buck Boulevard Substation to the Julian Hinds substation, or b) a 6.7 mile 230 kV single circuit line to a new Midpoint Substation with connection to the existing DPV1 500 kV line or c) both transmission modifications. Significant modifications to the Buck Boulevard substation are required.

[2] In the generator interconnection paradigm per the Federal Energy Regulatory Commission's (FERC) requirements an Interconnection Application is filed, the applicant's facilities are described, the interconnection point is identified, a System Impact Study Agreement is signed and fees are paid. The CA ISO's tariff provides generally that an applicant secures a place in the queue for new projects when their application is received. Until recently the applicant failed to submit an Application for Interconnection to Western and SCE in a timely manner. As a result the queue position of the BEP II project is behind that of the proposed DPV2 line and the BEP I BEPTL plan.

project's interconnection to the electric grid, as well as any facilities beyond the project's interconnection with the existing transmission system that are required as a result of the power plant interconnection to the California transmission system. Facilities required for interconnection of the project and those that are a reasonably foreseeable consequence of the project beyond the project's interconnection with the existing system are defined as "downstream and analyze facilities". The Energy Commission is also required to provide enough information on the project for the Energy Commission to conduct such an analysis to identify the "whole of the action" the information available does not. Staff relies partially on the input from the CA ISO and Western in its identification of downstream facility requirements.

Caithness Blythe II, LLC (applicant) filed an AFC to the California Energy Commission to construct a nominal 520-megawatt (MW) natural gas-fired combined cycle generating facility to be located about 5 miles west of the City of Blythe near Interstate 10 and the Blythe Airport (BEP II, 2002a, Application for Certification, 2-20-02). The applicant proposes to connect their BEP II project to Western's existing Buck Boulevard Substation where the Blythe Energy Project Phase I (BEP I) is presently interconnected. According to the AFC, BEP II was planned to be on-line in the summer of 2006 (BEP II, 2002h), however this date is infeasible given the status of the siting process and construction timelines. At this time staff believes that the earliest the plant could come on-line would be in mid to late 2008 depending on the new transmission option(s).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

TSE Table 1 provides a brief list of the LORS that apply to this analysis. A detailed description of these LORS is provided in TSE Attachment 1.

TSE Table 1
Laws, Ordinances, Regulations, and Standards

Applicable LORS	Description
Regional	
North American Electric Reliability Council (NERC) Planning Standards	Principles designed to insure the adequacy and security of the transmission network
Western Electric Coordinating Council (WECC) Reliability Criteria	Insure continuity of load service and protection of the interconnected grid.
National Electric Safety Code 1999 (NESC	Provides electrical, mechanical, civil and structural requirements for overhead electric line construction and operation
Western, General Requirements of Interconnection	Requirements for Interconnection, additions and modifications to Western grid.
State	
CPUC GO 95	Rules for overhead line construction
CA ISO/FERC Electric Tariff	Provides guidelines for transmission additions/upgrades within the CA ISO controlled grid.

CA ISO Reliability Criteria	Incorporate NERC and WECC standards and some additional requirements.

EXISTING FACILITIES AND RELATED SYSTEMS (SETTING)

The existing transmission facilities in the vicinity of the BEP II project area and generating plant and facilities which deliver power to the Devers Substation include the following (See **TSE Figure 1** attached):

- Buck Boulevard 161/230 kV Substation owned by Western (approved by the Commission in 2001 when the BEP I project was approved).
- Blythe 161 kV Substation. This Western substation is connected to the Buck Boulevard 161/230 kV Substation by an 1800 foot 161 kV single circuit line (the line was approved by the Commission in 2001 when BEP I was approved).
- Devers-Palo Verde (DPV1) line owned by SCE.
- Parker-Gene 230 kV line owned by Western.
- Gene-Camino-Eagle Mountain-Julian Hinds 230 kV line owned by Metropolitan Water District (MWD) and operated by SCE.
- Julian Hinds-Mirage-Devers 230 kV Line owned by SCE.
- Parker-Harcuvar-Hassyampa 230 kV line owned by Bureau of Reclamation (BOR) and operated by Western.
- Coachella-Ramon-Mirage 230 kV line owned by Imperial Irrigation District (IID).
- Coachella-Devers 230 kV line: the Coachella-Mirage section owned by IID and the Mirage-Devers section owned by SCE.

The Blythe Substation, which is a part of Western's "South of Parker" transmission system, is connected with the following:

1. Blythe-Knob 161 kV line owned by Western.
2. Parker-Blythe 161 kV line owned by Western.
3. Parker-Headgate-Blythe 161 kV line owned by Western.
4. Niland-Blythe 161 kV line owned by Imperial Irrigation District (IID).
5. Path 59: Interconnection between Western and SCE systems via Path 59 which is a bus-tie between Western's Blythe Substation and SCE's Blythe (Blythesc) Substation.
6. Eagle Mountain-Blythesc 161 kV line owned by SCE.

Western's Blythe and Parker Substations receive significant hydropower from Western's Hoover, Davis and Parker Dams, and transmit power to Arizona and the lower Colorado River areas served by IID and Arizona Public Service (APS).

TRANSMISSION OPTIONS

In view of limited transmission capacity in the "South of Parker" transmission system and in the existing DPV1 line, staff believes that accommodating the power output from the existing 520 MW BEP I plant and from the proposed 520 MW BEP II plant to the CA ISO grid warrants consideration of the following major transmission plan options:

a. A new bulk 500 kV transmission line or a double circuit 230 kV line from Buck Boulevard Substation to SCE's Devers (or Mirage) Substation similar to the proposed DSWTP being sponsored by IID and Desert Southwest Power (DSP).

b. Construction of a Devers-Harquahala 500 kV line (generally known as the DPV2 line currently proposed by SCE), with a Midpoint Substation at Blythe (with provision for BEP II interconnection at the Midpoint Substation) instead of going directly to Devers. The above DSWTP line could be planned as a part of the proposed DPV2 line between Midpoint and Devers.

c. Construction of the BEP I sponsored BEPTL plan (which would deliver power from BEP I plant only and would not accommodate output from BEP II).

d. Construction of the BEP I sponsored 230 kV transmission line from Buck Boulevard Substation to Julian Hinds Substation and reconductoring of the existing 230 kV line between Julian Hinds and Mirage Substation to achieve higher capacity (will deliver power from the BEP I plant only).

The BEPTL modification plan was filed by Blythe Energy on October 12, 2004, as a petition to amend the Blythe Energy project (BEP I) to build transmission modifications from the Buck Boulevard Substation as follows: a) a 67.4 mile single circuit 230 kV line from the Buck Boulevard Substation to the Julian Hinds substation, or b) a 6.7 mile 230 kV single circuit line to a new Midpoint Substation with connection to the existing DPV1 500 kV line or c) both transmission modifications. Significant modifications to the Buck Boulevard substation are required. The BEPTL plan will deliver power only from BEP I plant to the CA ISO grid.

In staff's view, the proposed DSWTP 500 kV line between the Buck Boulevard Substation or Midpoint Substation and the Devers Substation would provide the most comprehensive and expedited solution to relieving the inadequate transmission capacity between the Blythe area and the CA ISO grid. The DSWTP has the potential capability to have a lower overall cost per megawatt of transmission capacity than other new transmission options being pursued, and also could minimize environmental impacts in the BLM designated transmission corridor by eliminating the short-term need for other lines in the corridor. The DSWTP line likely is capable of delivering 1040 MW power from both the BEP I and BEP II plants to the CA ISO grid and would unload power flows in the "South of Parker" lines of the Western system.

PROJECT DESCRIPTION

Although staff provides the following project description, the applicant's proposed interconnection facilities as described below cannot be planned and implemented without Western approval because there would be significant BEPTL pre-project facilities assumed installed in Western's Buck Boulevard Substation before BEP II could

be interconnected. In the tariff interconnection paradigm facilities that have not been approved by the Commission still must be considered as part of the pre-project configuration.

The BEP II site would be located approximately 2,000 feet southwest of the Western Buck Boulevard 161/230 kV Substation. The BEP II would consist of two combustion turbine generators (CTG), each with an output of approximately 170 MW and one 180 MW steam turbine generator (STG), for a total plant nominal output of 520 MW. Each of the generating units would be connected to a dedicated 225 MVA, 16/500 kV step-up transformer and the high voltage terminals of each transformer would be connected to the new BEP II 500 kV Integration Switchyard switch bays by overhead conductors (See **TSE Figures 4 & 5**, attached).

BEP II INTEGRATION SWITCHYARD

The new BEP II 500 kV Integration Switchyard would have four switch bays with 500 kV circuit breakers. The high voltage transformer terminals of two CTG and one STG units would be connected by overhead conductors to three switch bays. The fourth bay would be connected to a 500 kV 2-2156 Aluminum Conductor Steel Reinforced (ACSR) interconnecting line to a new 500 kV substation to be built as an expansion of the existing Buck Boulevard Substation within its fence line. Since the diagrams provided by the applicant are conceptual and have no specific details, staff's description is, therefore, preliminary. The applicant would design, build, own and operate the BEP II Integration Switchyard.

TRANSMISSION INTERCONNECTION FACILITIES AND BUCK BOULEVARD 500 KV SUBSTATION

The new BEP II 500 kV Integration Switchyard is proposed to be interconnected to the existing Western Buck Boulevard 161/230 kV Substation by building a new approximately 2500 foot 2-2156 ACSR conductor 500 kV transmission line to be built by Western or the applicant. The line would carry the full generation output of the BEP II to the Buck Boulevard 500 kV Substation to be built by Western within the fence line of the existing 161/230 kV substation. The new Buck Boulevard 500 kV Substation would have three switch bays with 500 kV circuit breakers. The proposed 500 kV substation would be connected to the existing Buck Boulevard 161/230 kV Substation by installing a 400 MVA 500/230/161 kV step-down dual voltage transformer in the new substation. The third 500 kV switch bay would be used to connect the new 118-mile DSWTP 500 kV line to SCE's Devers Substation. Since the diagrams provided by the applicant are conceptual and have no specific details, and Western has not yet confirmed the layout plan for interconnecting facilities at the Buck Boulevard Substation, staff's description is, therefore, preliminary (See **TSE Figures 4 & 5**, attached).

DSWTP 500 KV TRANSMISSION LINE

The new 118-mile 500 kV line from Buck Boulevard Substation to Devers Substation is sponsored by IID and DSP as the DSWTP line. The DSWTP line is proposed to provide for additional power flow from the BEP II generation unit or from the combined

generation output from both BEP I and BEP II to the CA ISO grid. It would serve as the project's primary transmission service (See **TSE Figures 3 & 4**, attached). No information has been received by the staff directly from SCE or Western describing the specific details of the new facilities and/or modifications involved in the SCE and Western substations to accommodate the new line. Also, the BEP I owner has not agreed that its generating units remain connected to the Buck Boulevard Substation as described by BEP II.

Staff observes that the feasibility of building the DSWTP line in a timely manner before the projected on-line date of the BEP II plant (summer 2006) is impossible given that the final EIS/EIR has not yet been published. Additionally, it is not feasible to connect the proposed DSWTP line to the Buck Boulevard Substation without Western approval (given the proposed BEPTL facilities) and to the Devers Substation without CA ISO approval.

ALTERNATIVE TRANSMISSION INTERCONNECTION FACILITIES

The applicant initially considered four transmission interconnection alternative options as follows (BEP II, 2003c):

1. Option 1: A double circuit 80-mile 230 kV line with 2-1272 ACSR conductor from the BEP II 230 kV switchyard to IID's Midway 230 kV Substation. The alternative also included a new 230 kV line with 2-1272 ACSR conductors from IID's Highline 230 kV Substation to the El Centro switching station.
2. Option 2: A double circuit 80-mile 230 kV line with 2-1272 ACSR conductors from the BEP II 230 kV switchyard to IID's Midway 230 kV Substation.
3. Option 3: A double circuit 120-mile 230 kV line with 2-2156 ACSR conductors from the BEP II 230 kV switchyard to SCE's Devers 500/230 kV Substation.
4. Option 4: A 120-mile 500 kV line with 2-2156 ACSR conductors from the BEP II 500 kV switchyard to SCE's Devers 500/230 kV Substation.

As a result of the BART feasibility and screening study, the applicant chose the preferred transmission option over the preceding alternatives as: A 118-mile 500 kV line (DSWTP line) with 2-2156 ACSR conductors from the Buck Boulevard 500 kV Substation to SCE's Devers 500/230 kV Substation, a 500 kV interconnection line from the BEP II 500 kV Integration switchyard to the new Buck Boulevard 500 kV Substation with a 500/230/161 kV step-down transformer at the new Buck Boulevard 500 kV Substation (BEP II, 2003f).

As previously discussed, staff understands that the applicant is pursuing with SCE other interconnection alternatives not presently described to the Commission. Staff believes those new alternatives include a termination on the DPV1 line or the proposed DPV2 line (CA ISO, 2005, DSP, 2005).

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

In a typical interconnection paradigm a System Impact Study (SIS) for connecting a new power plant to the existing power system grid is performed by the transmission owner to determine the required transmission facilities to interconnect the plant to the grid, and identifies downstream transmission system impacts and their mitigation measures. The SIS assures conformance with system performance levels as required by utility reliability criteria, NERC planning standards, NERC/WECC reliability criteria and CA ISO reliability criteria. The SIS determines both positive and negative impacts, and for the reliability criteria violations (i.e., the negative impacts) determines the alternate and preferred additional transmission facilities or other mitigation measures. Mitigation measures typically include: a) Special Protection System(s) which ramp down or drop a generating unit, b) predetermined operational measures establishing a generating unit's output, c) building new transmission facilities, d) putting higher capacity conductors on an existing transmission line, e) the use of intra zonal or inter zonal congestion management. The SIS 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 system configuration without the new generation project is referred to as the "pre-project" configuration and it establishes the baseline for identification of impacts caused by the new generation project. Establishment of the pre-project system configuration is rigorously required by FERC's requirements, and utility and CA ISO conforming tariffs to assure non-discriminatory access to the transmission grid. In the generator interconnection paradigm per the Federal Energy Regulatory Commission's (FERC) requirements, an Interconnection Application is filed, the applicant's facilities are described, the interconnection point is identified, a System Impact Study Agreement is signed and fees are paid. The CA ISO's tariff provides generally that an applicant secures a place in the queue for new generation projects when their application is received.

The SIS 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 the generators and transmission system), voltage collapse, loss of loads or cascading outages and short circuit duties. The study must be conducted under normal conditions (N-0) of the system (see Definition of Terms) 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, 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. Equipment that is loaded beyond 100 percent of its rating constitutes a violation of the reliability criteria. Generally voltages must be within 95 percent and 105 percent of the base level.

The SIS is followed by supplemental studies conducted by the transmission owner with details provided in a Facility Study (FS) or a Facility Cost Report. The Facility Study determines engineering details and costs for mitigation measures required to assure that system reliability criteria violations are resolved and evaluates the costs ascribed to the generation developer for interconnection of the generating unit.

BART STUDY

Background

The CEC staff initiated a workshop to help the applicant prepare a computer model of a base case for the BEP II project on September 10, 2002 in Ontario, CA. The workshop was attended by the CEC staff, the applicant and their representatives, the representatives of affected transmission stakeholders (SCE, Western, MWD, IID, SDG&E (San Diego Gas & Electric) and others (Arizona Public Service (APS), and Salt River Project (SRP)). The purpose of the workshop was to build a consensus regarding system computer model base cases for a 2006 summer peak electricity demand and a 2006 light spring electricity demand conditions. Accordingly, a 2006 summer peak pre-project base case was developed by K. R. Saline and associates, the applicant's consultant, from the WECC 06HS2SA base case published by WECC in June, 2002. Subsequently, a 2006 spring pre-project base case was developed by K. R. Saline and Associates from the 2006 summer peak pre-project base case by reducing loads and generation in the SCE system and loads in the IID system.

During the period between March, 2002 and August, 2003, the applicant submitted in total five different system studies, a SIS performed by SCE (BEP II, 2002c) and four BART studies (BART studies; BEP II, 2002h, 2003b, 2003c, 2003h, 2003f) performed by K. R. Saline and Associates for screening and feasibility of various alternative interconnections and new transmission options. The applicant finally selected the configuration dated August 14, 2003, considered as a feasibility study, for CEC certification with identified BEP II generator interconnection facilities and the proposed DSWTP 500 kV line. The Study was performed under 2006 summer peak and 2006 spring conditions. In the summer peak base case, the interconnection facilities were not modeled according to the selected project configuration. Instead the Study modeled the project interconnection facilities and the new transmission line (BART SC4 base case) for the summer peak case as follows:

a. BEP II 500 kV and 230 kV Switchyards (BEP II units connected to BEP II 230 kV Switchyard bus) with a new short 230 kV interconnecting line between BEP II 230 kV switchyard and Buck Boulevard 230 kV Substation, and with two units of BEP I connected to Buck Boulevard Substation 230 kV Bus and one unit of BEP I connected to Buck Boulevard Substation 161 kV Bus.

b. A 500/230 kV transformer bank at the BEP II Switchyard.

c. A new 120-mile 500 kV line with 2-2156 ACSR conductor from the BEP II 500 kV Switchyard to SCE's Devers 500/230 kV Substation.

The study for spring case modeled the project interconnection facilities and the new transmission line (BART SC4 spring base case) as the selected project description above.

Scope of the BART Study

The August 14, 2003 BART study was considered by the applicant as a feasibility study in support of BEP II generator interconnection and provision for a new bulk 500 kV transmission line capacity to deliver power to the CA ISO grid at the Devers Substation (BEP II, 2003f).

The study modeled the proposed BEP II project for a net output of 520 MW and also modeled the BEP I 520 MW net power output (the BEP I plant is already on-line and interconnected to the Buck Boulevard Substation). The Power Flow studies were conducted by K. R. Saline and Associates with and without BEP II, with the interconnection facilities and the new DSWTP 500 kV transmission line for 2006 summer peak and 2006 spring system conditions. Analyses was done for normal (N-0), single (N-1) and credible double contingency (N-2) conditions. The spring study post-project base case was modeled according to the project configuration, but it was developed from the summer case by reducing loads and generation. The summer study post-project base case was not modeled according to the project configuration, but modeled with many approximations. While the applicant relies on the BART study, staff does not support its system assumptions or conclusions. The conclusions, which directly follow, apply to the study results submitted. Staff includes them here only as background.

Power Flow Study Results

Based on the August 14, 2003 BART study results, there are some adverse impacts following certain outages on the electrical grid due to interconnection of the BEP II as proposed. A summary of the overload violations under 2006 summer peak and spring conditions has been provided in Tables SC4.0, SC4.1, SC4.2, SC4.0 Spring, SC4.1 Spring and SC4.2 Spring of the study report (BEP II 2003f).

Mitigation of Overloaded Facilities and Comments

To offset the identified post-project overload violations due to interconnection of BEP II, the applicant selected mitigation measures without any written concurrence from the respective transmission owners and/or CA ISO. Staff requested the applicant (per CEC Data Request number 227e dated May, 2003), to provide a letter or a report from the respective transmission owner and, where applicable, from the CA ISO verifying the rationale and feasibility of the mitigation measure and its implementation for each criteria violation prior to the on-line date of the BEP II plant. No report or letters were received resulting in uncertainty about the feasibility of mitigation measures. Provision of such a letter or report is now moot as the overloaded facilities and mitigation measures will change when BEP II is analyzed in a new Blythe area transmission configuration.

Transient Stability Study

The applicant submitted a BART Stability Study report dated May 18, 2004 prepared by General Electric Energy. The study was conducted with a 2006 summer peak case and a 2006 spring case. The stability analysis shows that the system is both transiently and dynamically stable for all selected critical contingencies except for the loss of the Buck

Boulevard-Devers 500 kV line. The analysis shows that this reliability criteria violation can be mitigated with the tripping of BEP II 520 MW power output (BEP II 2004a).

Short Circuit Study

The applicant submitted a BART Short Circuit Study report dated May 18, 2004 prepared by General Electric Energy. The study was conducted with a 2006 summer peak case with and without BEP II. The analysis shows that the addition of the DSWTP 500 kV line has the greatest impact on fault current increments in the Blythe area. However, the analysis was found incomplete as the breaker fault interrupting ratings at the selected substations were not provided by the applicant from the transmission owners (BEP II 2004a).

Comments on the BART Study

The applicant considered the August 14, 2003 BART study as a feasibility study and stated that it was not intended as a SIS. While staff concurred with the applicant that the purpose of the BART study was as a screening and feasibility study and not as a SIS, staff observes the BART study itself is incomplete and the study results are also preliminary due to system modeling issues and other reasons stated below.

The spring study post-project base case was modeled according to the project configuration as described above, but the summer study post-project 2006 base case (BART SC4 base case) was not modeled according to the project configuration, but instead with many physical, electrical approximations.

Staff modified the modeling of the summer BART SC4 CEC base case for 1) the 500/230/161 kV transformer at the Buck Boulevard Substation, 2) the new 500 kV line from the Buck Boulevard Substation to the Devers substation, and 3) the 500 kV short Interconnection line from the BEP II Switchyard to the Buck Boulevard Substation. These changes were required so that the impedances (similar to the resistance) and configurations of the facilities would be accurately accounted for in the analytics of the computer analysis. After staff modified the modeling with the information available, staff's preliminary analysis found that the power flow to Devers from the Buck Boulevard Substation would be about 818 MW instead of 730 MW as shown in the BART SC4 CEC case

.

Staff believes that discrepancies in modeling the new transmission elements for the interconnection of BEP II and their effects on the power flows result in a failure to identify realistic adverse impacts under normal and contingency conditions in the affected systems (SCE, IID, Western, San Diego Gas & Electric (SDG&E) and CFE (in Mexico)). Consequently, the study results would be affected and the selected mitigation measures could be wrong, ineffective or partially effective, and conformance with NERC/WECC, NERC, Western Interconnection and CA ISO planning standards and reliability criteria would not be assured.

In the development of the 2006 pre-project spring base case, staff found that the 2006 summer peak pre-project base case was converted to a spring case by reducing load and generation in the SCE system and by reducing loads in the IID system. Staff also observes that the BART study results dated August 14, 2003 show more adverse

impacts under spring conditions than under summer peak conditions. Staff, therefore, recommends that the new spring or autumn (off peak) base case development in the new SISs should be initiated from an original spring or autumn case published by WECC and be further modified for applicable study area systems to suit the requirement of the study. Staff believes that a study with such a spring or autumn case would provide more confident system impact results for power flow and for transient stability analyses.

In the August 14, 2003 BART study report power flow diagrams for the overload violations as discussed above and as mentioned in the tables of the report (except two violations) were not attached. Staff requested the applicant to submit such power flow diagrams per Data Request number 227 dated May 2003. Staff expected that the power flow diagrams for each overload violation would be furnished with the SISs to be performed by SCE and Western.

To eliminate the identified post-project overload violations due to the addition of BEP II, the applicant selected mitigation measures without any written concurrence from the respective transmission owners and/or CA ISO. Staff requested the applicant (per CEC Data Request number 227e dated May, 2003), to provide a letter or a report from the respective transmission owner and, where applicable, from the CA ISO verifying the rationale and feasibility of the mitigation measure and its implementation for each criteria violation prior to the on-line date of the BEP II plant. Staff expected that in the SISs to be performed by SCE and Western, the mitigation measures would be selected by the applicant in concurrence with the respective transmission owner. No letters or reports have been received which results in uncertainty about the feasibility and validity of the outdated BART study.

The BART short circuit study report was also found incomplete as the breaker fault interrupting ratings were not provided by the applicant from the respective transmission owner(s). The BART study was also never formally approved by the stakeholders (SCE, Western and IID) and CA ISO.

Staff, therefore, finds that the BART study is inaccurate, incomplete and outdated, and does not meet the requirements of NERC/WECC and CA ISO reliability and planning standards.

CHANGED SYSTEM ASSUMPTIONS AND REQUIREMENTS FOR THE NEW SYSTEM IMPACT STUDIES

Because of the BEPTL modification plan in the Blythe area as stated above, and to realize delivery of 520 MW of BEP I power from the Buck Boulevard Substation to the CA ISO grid, the transmission system in and around the Buck Boulevard Substation would undergo substantial additions and changes. Since BEPTL is ahead of BEP II in the generation/transmission queue, Western and SCE have to provide a priority to the BEPTL in accordance with the applicable tariffs and are progressing first with the SISs for BEPTL. Subsequently, SCE would perform a BEPTL Facility Study, and finalize the BEP I sponsored transmission plan(s) for transmission lines emanating from the Buck Boulevard Substation. Because the BEP II applicant has signed Interconnection study agreements with SCE and Western, the new SISs for BEP II to be performed later by

SCE and Western would include the BEPTL transmission plan(s) in the base case[3] and eventually have a different pre-project scenario of the transmission network in the Blythe area than that analyzed in the BART study (See **TSE Figures 1, 2, & 3**, attached). Staff anticipates the new SISs would have different system reliability impacts depending on their interconnection alternatives. Staff, therefore, concludes that the BART study is inaccurate and incomplete, and the BEPTL plan completely nullifies the BART study.

Moreover, staff became aware recently that in the SIS to be performed by SCE, the applicant is pursuing different interconnection and transmission alternatives than those proposed before the Commission, such as interconnecting to the existing DPV1 500 kV line or the SCE sponsored proposed DPV2 500 kV line. Additionally, the status of the DSWTP line is uncertain and publication of its final EIS/EIR report by the BLM and sponsors has been pending for an indefinite period (per BLM). Staff also became aware recently that the sponsors of the proposed DSWTP line are negotiating with SCE so that instead of building an independent DSWTP line (in the same planned BLM transmission corridor as the existing DPV1 and proposed DPV2 lines), the DSWTP potentially could become a part of the SCE sponsored DPV2 500 kV line between the Blythe area and Devers with a Midpoint Substation near Blythe. Therefore, the feasibility of building the new DSWTP line itself in a timely manner before the applicant's stated on-line date of 2006 for BEP II is uncertain and impractical, and the target date for completion of the DPV2 line by SCE is estimated to be 2009.

In view of the uncertainty of the DSWTP line, the BEP II undefined interconnection and new transmission alternatives for the BEP II project, and time for permits and the construction schedule, staff believes that instead of the applicant's originally anticipated summer 2006 on-line date, the earliest the BEP II plant could come on-line would be mid to late 2008 depending on the new transmission option(s) and assuming the Commission approved the project. The SISs for BEPTL are being performed for 2008 system conditions with and without the DPV2 line for summer peak and autumn system conditions (Blythe, 2004a & 2004b). The new SISs for the BEP II interconnection would likely be required to be performed by SCE and Western on the same basis for 2008 or 2009 summer peak and autumn off-peak conditions as stated in the Conclusions and Recommendations. Staff is and will participate with the applicant, SCE, the CA ISO and Western (and other stakeholders) in the development of required System Impact Studies and Facility Studies.

A new SIS for interconnection of the BEP II plant to the Western's Buck Boulevard Substation with the DSWTP transmission option have recently been initiated by Western on behalf of the BEP II applicant. The study includes the BEPTL transmission plan and DPV2 line as a pre-project system configuration (Western, 2005). This is a notable recent development and conforms to staff's conclusions and requests for new SISs be performed by Western as well as SCE as stated above.

[3] The base case for a SIS models the California and other western state's entire transmission and generation system. The pre-project base case includes all transmission and generation facilities anticipated to exist just before the studied generating unit or transmission facility would come on line.

Staff has requested the applicant to provide SIS reports conducted in accordance with the generation/transmission queue on several occasions and the applicant has consistently refused to provide them. The applicant also has not directly provided any information about its recent alternative interconnection and transmission options to the CA ISO grid in response to staff's requests.

CA ISO REVIEW AND APPROVAL

Unlike other applications for certification where generating units connect directly to the CA ISO grid, since the Western system (Buck Boulevard Substation) is not a part of the CA ISO grid, the CA ISO is not responsible for ensuring electric system reliability for the generator interconnection to the Western System. However, the CA ISO is responsible for ensuring that delivery of BEP II generation to the CA ISO grid (SCE's Devers Substation or any other) through the proposed DSWTP 500 kV line from Western's Buck Boulevard Substation does not cause any potential reliability concerns. Should the BEP II project move forward with interconnection to the DPV1 or DPV2 line, the CA ISO will be responsible for evaluating system reliability impacts, and providing review and approval for interconnection of the project to the CA ISO grid. A SIS and a Facility study, with the queue generation and transmission projects properly modeled, are required for the CA ISO review and approval for interconnection of the DSWTP line or any other line to the CA ISO grid. Staff is uncertain when the new SIS reports will be available to the CA ISO and staff.

STATUS OF THE DSWTP 500 KV TRANSMISSION LINE

The BART feasibility and screening study first concludes that the project would require construction of the BEP II Integration Switchyard and 500 kV interconnection transmission facilities to Western's Buck Boulevard Substation as proposed by the applicant. However, the BART study also states that accommodating the power output of BEP II will require a new bulk power transmission line from Buck Boulevard Substation or the BEP II plant to Devers or other load centers in CA ISO grid. This is due to limited transmission capacity availability in the "south of Parker" Western system, especially given interconnection of the existing BEP I plant to the Buck Boulevard Substation. In response to this conclusion, the applicant stated that it would utilize the proposed DSWTP line (See **TSE Figure 3**, attached).

Despite the other transmission options available (described above), this is the only configuration staff is assessing since it is the configuration the applicant has requested the Commission to license. Staff believes that the proposed DSWTP 500 kV line would provide the most comprehensive and expedited solution to delivering 1040 MW power output from both the BEP I and BEP II plants to the CA ISO grid. However, staff has insufficient information from the applicant or sponsors about the status of building the DSWTP line and its expected completion date. No information has been received by the staff directly from SCE or Western about the specific engineering details of the new facilities and/or modifications involved in the SCE and Western substations to accommodate the DSWTP at its terminations.

Since 2003 IID, DSP and the Bureau of Land Management (BLM) have been jointly pursuing an EIS/EIR with various options and routes for a proposed DSWTP (BEP II, 2003g. Draft Environmental Impact statement/Environmental Impact Report (EIS/EIR),

03-25-03). According to the EIS/EIR the line would start from a new IID Hobsonway 230 or 500 kV Substation near the BEP II project and terminate at SCE's Devers 500/230 kV Substation and it could loop into IID's Coachella or Dillon Road 230 or 500 kV Substation before terminating at the Devers 500/230 kV Substation. This engineering description is not consistent with the system configuration as shown in the BART study where the DSWTP line starts from the Buck Boulevard Substation.

According to recent information from BLM, staff's understanding is that publication of the final EIS/EIR report by BLM and sponsors is deferred for an indefinite period. Moreover, staff became aware that the sponsors of the DSWTP line are negotiating with SCE so that instead of building a separate DSWTP line (in the same planned BLM transmission corridor beside the existing DPV1 and proposed DPV2 lines), it may become a part of the SCE sponsored proposed Devers-Palo Verde No. 2 500 kV line (DPV2) between Blythe and Devers with a Midpoint Substation at Blythe. Therefore, the feasibility of building the new DSWTP line itself in a timely manner before the projected on-line date of BEP II (summer 2006) remains still uncertain at this stage and the target date for completion of DPV2 line by SCE is now 2009, which staff believes is also uncertain. Consequently the feasibility of the BEP II project also remains uncertain.

CUMULATIVE SYSTEM RELIABILITY IMPACTS

Cumulative system reliability impacts can occur when a new generating unit or new transmission facility is connected to the grid and the increased or modified power flow of the new generating unit or new transmission facility affects a generating unit's or transmission line's later interconnection.

Cumulative system reliability impacts are evaluated based on the applicable generation/transmission queue. Each project requesting interconnection to the grid is evaluated based on existing conditions anticipated for its online date.

Staff believes the queue applicable to BEP II, as determined by the applicable interconnection tariffs, is 1) DPV2, 2) BEPTL and 3) BEP II and the DSWTP[4]. Staff has no studies with BEP II and the DSWTP (or alternative undefined interconnections) connected per their queue position (number 3), thus staff cannot identify even the "direct" impacts of the BEP II project. The direct impacts of BEP II must be established with and without the DPV2 line and with the BEPTL lines as the pre-project configuration (e.g., the existing system in mid to late 2008 and then BEP II modeled on-line in the same study year; thereby identifying the direct impacts caused by the BEP II project and any interconnection facilities). Once direct system reliability impacts are established, then approximate cumulative system reliability impacts can be estimated. In some instances cumulative environmental impacts can result from cumulative system reliability impacts. As an example, the stress caused by a generating unit ahead in the queue when combined with the stress caused by a lower unit may require construction of a new transmission line or reconductoring of an existing line.

[4] Staff established this conclusion based on the BEPTL SISs which do not include BEP II as an assumption in the studies and assesses the DPV2 line as operational and not operational.

Because the direct impacts of interconnecting BEP II in an unidentified manner cannot be determined, staff cannot identify what cumulative system reliability or environmental impacts would occur should a later generation unit or other transmission facility be proposed in the area.

Should staff receive adequate SISs for the BEP II project in the applicable queue, staff will evaluate cumulative system reliability impacts based on available information at that time.

COMPLIANCE WITH LORS

Staff concludes that the BART study submitted does not comply with NERC/WECC, NERC and CA ISO planning standards for the interconnection of a generating unit due to the various reasons stated above. Therefore, the project and its interconnection cannot be evaluated for conformance with system reliability LORS. Additionally, no firm information describing interconnection of BEP II to the Buck Boulevard Substation (or elsewhere) is available given that the BEPTL project facilities would be installed prior to any BEP II facility interconnection to the grid. Therefore, conformance with engineering LORS such as General Order 95, the National Electric Safety Code, IEEE grounding standards and Western and SCE interconnection standards cannot be evaluated. Staff, therefore, concludes that the identified interconnection facilities cannot be analyzed for conformance with engineering or system reliability LORS at this stage.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

No agency or public comments applicable to the TSE discipline have been received.

RESPONSE TO APPLICANT COMMENTS

In April of 2004 staff received the Applicant's comments on Transmission System Engineering. In the comments, the Applicant recommends words for a condition of certification that would ostensibly allow the project to go forward without information on the interconnection configuration. As discussed previously staff does not believe such a condition is appropriate given the lack of information needed to analyze transmission system impacts.

The applicant suggested the following language:

> **Condition TSE No. _____:** The Project Owner shall not commence construction until the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) has received all necessary permits. The Project Owner shall not deliver to the grid more than ____ megawatts combined from the Blythe I and Blythe II projects until the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) has been constructed and is in operation.
>
> **Verification:** Not later than 30 days prior to commencement of construction, the Project Owner shall provide to the CPM a statement from the owner(s) of the

Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) that all necessary permits have been issued. Not later than 30 days prior to delivery to the grid from the Blythe I and Blythe II projects of greater than ____ megawatts, the Project Owner shall submit to the CPM a statement from the owner(s) of the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) that the project is operational.

Staff advised the applicant at the January 26, 2005 PSA workshop that we would not support the suggested condition because it could not suffice adequately for identification of the applicant's project facilities and alternatives, assessment of impacts and mitigation measures, conformance with LORS and the Commission's responsibility to assure conformance with CEQA. Staff has numerous problems with the specific provision of the suggested condition as stated:

- The condition provides for an unprecedented situation where an applicant could propose an "essential" project facility, the Commission approve it and then an unknown facility with unknown impacts (both reliability, engineering LORS, and environmental) be substituted after project approval. The remedy for securing adequate capacity to deliver power to the grid is to request interconnection, secure SISs and approval to interconnect. Depending on an unknown facility is a clear violation of the Commission's responsibility to analyze impacts pursuant to CEQA before a project is approved. The Commission must identify and analyze the "whole of the action" before approving a proposed project. A critical piece of BEP II is inadequately described and, therefore, cannot currently be analyzed.

  Nor does the condition acknowledge that the applicant is currently pursuing other interconnection configurations. Were BEP II approved with the proposed condition the project owner would be prohibited from seeking a modification to the interconnection configuration. Title 20, California Code of Regulations, Section 1769 allows a modification to a permit only if the Commission finds either that there has been a substantial change in circumstances since the project was certified or the change is based on information not known prior to certification. Clearly, the applicant could meet neither test.
- The condition also restricts the combined output of both BEP I and BEP II pending some unknown transmission facility being constructed and operating in the future. Also, the condition could be taken as limiting output of a generating unit (BEP I) already licensed by the Commission that has sufficient outlet capacity so that BEP II could operate. Staff concludes that it would be impossible to fashion a contractual provision under the Commission's authority to control two (or even one) generating unit's output; this is FERC's purview and that of the CA ISO and Western in their conforming tariffs.
- The verification provides 30 days for the CPM to decide if necessary permits for the DSWTP or some other unknown transmission outlet are sufficient to reliably and fully accommodate an output of 1040 MW (BEP I and BEP II). Because the purpose of the ill-founded Condition is to secure adequate outlet capacity, the existence of mere permits in a verification would not suffice. The Applicant would have to provide a SIS and FS and path rating studies for either the DSWTP or an alternative outlet.

Additionally, approval by Western and the CA ISO (where applicable) would be required because there are instances where permits from a siting and environmental perspective may exist but system reliability analysis and outlet capability not exist (Note worthy at present is the DSWTP which does not have the required SIS, FS and path rating studies to allow interconnection or operation—but has a DEIS/DEIR.) Assuming a SIS, FS, path rating studies and approval by the CA ISO or Western (where applicable) were provided staff estimates we would need approximately three months to recommend approval before the full Commission assuming adequate environmental review by an authorized agency. That also assumes that if an alternative outlet is proposed the Commission does not have licensing jurisdiction. Several transmission alternatives previously proposed by the Applicant fall under the Commission's licensing authority. Additionally, an alternative presently requested by the Applicant for termination on DPV1 is under the Commission's licensing authority. Should that occur staff estimates about 6 months for approval.

APPLICANT'S APRIL 2004 COMMENTS

The applicant also provided comments in April 2004 on information that they agreed to provide as follows (only the major heading and staff's response are presented here):

Stability and Short Circuit Studies

The applicant states that the studies were completed. Staff concludes they were not completed, as breaker ratings must be identified to determine if breakers must be replaced but this was not done. This issue is moot as the pre project configuration, due to the BEPTL, has changed and this will change the results of the analysis.

Plan View of Buck Boulevard Substation:

A conceptual plan was presented. This plan however lacks engineering details and is obsolete given the pre project configuration caused by the BEPTL. It is infeasible from an engineering perspective to connect the BEP II project as depicted and also simultaneously connect the BEPTL project as they propose. The BEP II project configuration combines most of both the BEP I and BEP II output power on the Buck Boulevard bus and transmits almost all of the power to the Devers Substation via the DSWTP. The BEPTL project configuration places only BEP I power on the Buck Boulevard bus and transmits that power to the Julian Hinds Substation or DPV1 via one or two 230 kV lines. The BEPTL project configuration does not model the BEP II project or the DSWTP connected to the grid at all. Staff is not suggesting that some manner of connecting BEP I and BEP II and the DSWTP plus the two 230 kV lines (or some combinations with fewer lines) cannot be developed but rather that there is no defined proposal available at this time. Because there is no proposal the design of the Buck Boulevard Substation in unknown and conformance with engineering LORS cannot be determined. Likewise, because the configuration of lines emanating from Buck Boulevard is unknown the spatial delivery of power to the grid is unknown, thus system reliability criteria violations and mitigation measures are unknown. The BEPTL is ahead of the BEP II project in the queue and they have first rights to interconnection.

Plan View of the Integration Switchyard:

While a plan view of the originally proposed Integration Switchyard was provided it is not up to date given that the proposed BEPTL project is now ahead in the queue.

Verification of Mitigation Measures for Criteria Violations per BART Executive Summary:

Staff never received written verification from the transmission owners and CA ISO agreeing that the BART study was sufficient to identify any network upgrades with possible environmental impacts. Such verification is now moot, as staff knows that SCE, Western and the CA ISO cannot provide conclusions based on an outdated study where significant system changes are known to be occurring. The CA ISO has indicated that they are unable to provide comments to the Commission based on the BART study which is known to be outdated, nor can they provide a preliminary approval of interconnection of the DSWTP or testimony before the Commission.

Devers Import Nomogram:

The applicant believes an existing CA ISO approved nomogram can be used for the BEP II generation impacts. Staff disagrees; the feasibility of using an existing nomogram for interconnection of BEP II and the DSWTP can only be determined by appropriate studies conducted per the queue, and provision of a SIS and FS approved by the CA ISO and subject to interconnection approval by Western. The CA ISO, SCE and Western are bound by their tariffs to provide non-discriminatory access to the grid and as such, approvals are provided in accordance with the queue.

Staff makes the following comments on the applicant's memorandum regarding "BART Consensus on Mitigation for Critical Contingencies for BEP II:"

- The memorandum notes that prior to interconnection of the BEP II facility "additional power flow work, transient stability and short circuit studies were to be performed as part of [the] final system impact studies by each of [the] BART Participants (sic) pursuant to their individual OATT[5] Processes (sic)."

  Staff anticipated that while the joint studies would not suffice for the OATT processes and approvals provided per that process the joint studies would provide staff with a sufficient confidence level regarding the system reliability criteria violations and the mitigation measures required by each stakeholder (Western, SCE, MWD, CA ISO, APS, SDG&E or others) that we could identify the "whole of the action" per CEQA; this did not occur. The interconnection studies morphed into feasibility studies for many alternative interconnections to the grid and the stakeholders indicated that they could not use the BART study to indicate system reliability criteria violations and mitigation measures. Upon learning of these developments staff informed the Applicant that SISs performed per the queue would have to be provided. The applicant refused.

- The memorandum also states: "For the purposes of the CEC review for the Final Staff Assessment ("FSA") that is expected to be completed the end of April 2004, the above conclusions support that no new additional transmission facilities or upgrades that have not already been identified will be required outside the SCE, Western, and IID substation fences (just inside the fences such as breakers, switches, etc.)". This assertion implies that the conclusions flowing from the BART study were sufficient to

[5] OATT is an acronym for Open Access Transmission Tariff. Staff has previously referred to the Open Access Transmission Tariff simply as the applicable tariff or the conforming tariff.

identify the system reliability criteria violations and the acceptability of those mitigation measures by the affected transmission owners and the CA ISO. Staff disagrees with that assertion as previously discussed. The assertion also suggests that the staff would find that the conclusions flowing from the BART study were sufficient. Staff does not agree with this conclusion as previously stated.

The deficiencies noted by staff on the BART study are historically substantial but presently irrelevant and immaterial to what will actually become an interconnection of the BEP II project --should the Commission approve it and the applicant build it. The applicant either did not file timely for a position in the generation/transmission queue or they fell out of it and therefore the applicant's "project" is undefined. The FERC, CA ISO, SCE and Western tariffs require BEP II to be studied per the queue. It has not been, and because the proposed BEPTL project facilities must be assumed to exist prior to connecting BEP II or the DSWTP, completely different impacts will occur. Staff anticipates that the BEP II project configuration will ultimately be significantly different than what the applicant has suggested based on the outdated BART study.

CONCLUSIONS AND RECOMMENDATIONS

While the existing information on system reliability impacts and the design of the Buck Boulevard Substation is incomplete and inappropriate for evaluation staff concludes as follows:

1) The BART study dated August 14, 2003, considered as a screening and feasibility study, is incomplete and the study results are preliminary. As stated in Staff's preliminary assessment (PSA), due to modeling discrepancies and approximations of the BEP II project interconnection facilities and the new DSWTP transmission line, and without a proper spring base case, staff is not confident that the Power Flow study results have identified all system reliability criteria violations and their degree of impacts in the affected systems of SCE, IID, SDG&E and Western. Also, the Short Circuit study report dated May 18, 2004 as submitted are incomplete as breaker fault interrupting ratings were not provided. Moreover, the mitigation measures selected by the applicant to eliminate identified overload violations in the Power Flow study were not verified with written consensus from the stakeholders (SCE, Western, IID) and CA ISO about the feasibility and rationale of the mitigation measures. The BART study was never formally approved by the stakeholders and CA ISO. Staff, therefore, concludes that the SIS submitted does not comply with NERC/WECC and CA ISO planning and reliability standards. Staff also believes the requirements of CEQA for identifying the "whole of action" would not be met if the project is approved without necessary studies. The applicant indicated previously that SCE and Western would perform new SISs with actual details of the project interconnection facilities and the DSWTP before staff's final assessment. The applicant has refused to provide new SISs. Staff is uncertain when the new SIS reports will be available to the CA ISO and staff.

2) The diagrams submitted for the project by the applicant for the proposed BEP II integration switchyard, interconnection facilities and Buck Boulevard 500 kV Substation are conceptual and indeterminate. The diagrams do not provide

specific details of the proposed new and modified installations with major equipment ratings including facilities for termination of the new proposed DSWTP 500 kV line at both ends. As stated in staff's preliminary assessment, full layout plans and one-line diagrams with detailed description of facilities are required. Staff, therefore, concludes that the identified interconnection facilities do not comply with engineering LORS at this stage and are subject to approval by Western. The termination facilities of the proposed DSWTP line at Devers Substation must be approved by SCE.

3) The BART study concludes that BEP II can be interconnected to the electrical grid at the Western Buck Boulevard Substation, but delivering the power output of the BEP II and/or BEPI, will require a new bulk power transmission line from the Buck Boulevard Substation or the BEP II Switchyard to Devers or other load centers due to limited transmission capacity availability in the "South of Parker" Western system. In this respect, the DSWTP 500 kV line was identified by the applicant and the BART study was performed with the DSWTP line. Staff believes that the proposed DSWTP 500 kV line would provide the most comprehensive and expedited solution to delivering 1040 MW power output from both the BEP I and BEP II plants to the CA ISO grid. However, the status of the DSWTP line is uncertain, since publication of its final EIS/EIR report by the BLM and sponsors has been deferred for an indefinite period for unknown reasons. Staff also became aware recently that the sponsors of the proposed DSWTP line are negotiating with SCE so that instead of building an independent DSWTP line in the planned BLM transmission corridor beside the existing DPV1 and proposed DPV2 lines, the DSWTP could become a part of the SCE sponsored DPV2 500 kV line between Blythe and Devers with a Midpoint Substation near Blythe. Therefore, building the new DSWTP line in a timely manner before the on-line date of BEP II (estimated by staff for mid to late 2008) is uncertain. The target date for completion of the DPV2 line by SCE is now 2009, which staff believes is also uncertain. Consequently the feasibility of the BEP II project also remains uncertain.

4) Staff became aware recently that the applicant has signed interconnection study agreements with SCE and is pursuing a different interconnection alternative than proposed before the Commission such as interconnecting to the existing DPV1 500 kV line or to the proposed DPV2 500 kV line. No engineering descriptions or system reliability studies are available for these terminations. The SISs to be performed by SCE for these terminations have not started yet. As such staff finds that the identified interconnection facilities to Western's Buck Boulevard Substation are uncertain, infeasible and speculative at this stage.

5) Because of the BEP I sponsored proposed transmission line modifications for delivering 520 MW of BEP I project power from the Buck Boulevard Substation to the CA ISO grid, the transmission system in and around the Buck Boulevard Substation will undergo substantial additions and changes if the modifications are approved. Since the BEPTL is ahead of the BEP II project in the generation/transmission queue, Western and SCE have to provide a priority to BEPTL and are, therefore, progressing first with the SISs for the BEPTL plan. SCE must first perform the BEPTL Facility Study and finalize the BEPTL plan in the Buck Boulevard Substation before a configuration for BEP II can be determined. Since the applicant has signed Interconnection study agreements

with SCE and Western, the new SISs for BEP II to be performed later by SCE and Western would include the BEPTL transmission plan in the base case and have a different pre-project scenario for the transmission network in the Blythe area than that assumed in the BART study. Staff anticipates the new SISs would have different system reliability impacts depending on BEP II's interconnection alternatives. Staff concludes that the BEPTL plan nullifies the BART study and therefore, the project related facilities in the Buck Boulevard Substation, the outlet lines for power delivery and the system reliability criteria violations and mitigation measures caused by interconnection of BEP II to the grid are unidentifiable at this time.

6) In view of the uncertainty of the DSWTP line and interconnection alternatives for the BEP II project, new system reliability studies, permits and construction schedule, staff believes that the earliest the plant could come on-line would be mid to late 2008. Also, since the BEPTL studies are being performed based on year 2008 system conditions with and without the DPV2 line, the new SISs would likely be performed by SCE and Western on the same basis for the 2008/2009 summer peak and autumn off-peak conditions.

7) Because the Western system is not a part of the CA ISO grid, the CA ISO is not responsible for the generator interconnection to the Western System. However, the CA ISO is responsible for ensuring that there are no reliability impacts on the CA ISO grid due to a generator interconnection on the Western system particularly when the interconnection point is electrically tied to the CA ISO-controlled grid. The CA ISO is also responsible for evaluating delivery of the BEP II generation to the CA ISO grid (SCE's Devers Substation or any other) through the proposed DSWTP 500 kV line from Western's Buck Boulevard Substation. Should the BEP II be planned to be interconnected to the DPV1 or DPV2 line, the CA ISO will be directly responsible for ensuring system reliability impacts and reviewing and providing an approval for interconnection of the project. A SIS/Facility Study, with the queue projects properly modeled, are required for the CA ISO review and approval for interconnection of the project.

8) Staff cannot identify either the direct system reliability impacts or the cumulative system reliability impacts.

9) Because staff's standard conditions are not sufficient to remedy the preliminary nature of the BART studies that are now nullified due to the proposed BEPTL plan and because staff cannot confidently identify the project facilities, no conditions of certification have been identified at this stage. A condition of certification that attempts to assure that the BEP II project not commence construction until the DSWTP line or some other unidentified line receives necessary permits in these circumstances cannot remedy a nonconformance with LORS and CEQA as far as the project itself and its impacts are concerned.

10) Staff recommends that the Commission not approve the indefinite BEP II project until critical information is provided because the project is speculative, undefined and infeasible. The impacts of the project and required mitigation measures are indeterminate and the Commission's responsibility to identify the "whole of the action" and to analyze the project impacts pursuant to CEQA before a project is approved cannot occur with available information.

INFORMATION NECESSARY FOR ADEQUATE EVALUATION

For staff to analyze and report the impacts of interconnecting the BEP II project and to provide recommended conditions of certification, the following information is needed[6]:

1) A SIS and Facility study (FS) to be performed by SCE, with the queue generation and transmission projects properly modeled, should include a Power Flow study under 2008/2009 summer peak and 2008/2009 autumn system conditions with and without the DPV2 line, a Transient Stability study, a Post-transient Power Flow study and a Short Circuit study and would report all downstream adverse impacts and selected mitgation measure(s) for each reliability criteria violation. The study may be performed with alternative interconnections and transmission options where applicable, but must identify a final interconnection plan and configuration with selected transmssion option(s). Additionally, the SIS must include assessment of impacts in the IID and SDG&E areas and be coordinated with IID, MWD and SDG&E including the acceptability of identified mitigation measures. Termination facilities for the proposed DSWTP line at the Devers Substation or for any other termination to the CA ISO grid must have CA ISO approval.

2) The SIS and Facility study to be performed by Western, with the queue generation and transmission projects properly modeled, should include a Power Flow study under 2008/2009 summer peak and 2008/2009 autumn system conditions with and without the DPV2 line, a Transient Stability study , a Post-transient Power Flow study and a Short Circuit and would report all downstream adverse impacts and selected mitgation measure(s) for each reliability crteria violation. The study may be performed with alternative interconnections and transmission options where applicable, but must identify a final interconnection plan(s) and configurartion with a selected transmission option. The identified interconnection facilities and termination facilities of the proposed DSWTP line at the Buck Boulevard Substation or any other interconnection to the Western grid requires approval from Western.

3) For any proposed new or modified downstream facilities, including reconductoring or a new transmission line, modification of a termination, or installation of circuit breakers, the environmental impacts must be identified and must include environmental mitigation measures.

4) Review, analysis and conclusions by the CA ISO on the SCE performed SIS and Facility studies. Should the BEP II be planned to be interconnected to the existing DPV1 line or the proposed DPV2 line or any other part of the CA ISO grid, the CA ISO will be responsible for ensuring system reliability impacts, and providing preliminary and final approval for interconnection of the project.

5) Plans and profiles with a description of the proposed facilities and one line diagrams for the BEP II Switchyard, Buck Boulevard Substation, termination facilities with identification of proposed major equipment and their ratings in concurrence with the respective transmission owner.

[6] The actual study years and study assumptions will be determined by Western, SCE and the CA ISO in consultation with the CEC staff.

6) All relevant information required by Title 20, California Code of Regulations, Appendix B, applicable to the applicant's power plant Integration Switchyard, outlet line, Buck Boulevard Substation and all downstream facilities .

7) An amended AFC which identifies the applicant's proposed facilites and those that the applicant desires to rely on to get their power to the grid and/or market.

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TSE ATTACHMENT 1: LORS

- 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 NERC/WECC Standards, certain aspects of the WECC standards are either more stringent or more specific than the NERC standards for Transmission System Contingency Performance. The NERC planning standards apply to interconnected systems and to individual service areas (NERC 1998).
- The National Electric Safety Code, 1999 provides electrical, mechanical, civil and structural requirements for overhead electric line construction and operation.
- The Western Electricity Coordinating Council (WECC) Planning Standards are merged with the North American Electric Reliability Council (NERC) Planning Standards and provide the system performance standards used in assessing the reliability of the interconnected system. Certain aspects of the NERC/WECC standards are either more stringent or more specific than the NERC standards alone. These standards provide planning for 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 WECC system is based to a large degree on Section I.A of the standards, “NERC and WECC Planning Standards with Table I and WECC Disturbance-Performance Table” and on Section I.D, “NERC and WECC Standards for Voltage support and Reactive Power”. These standards require that the results of power flow and stability simulations verify 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 a level that seeks to prevent system cascading and the subsequent blackout of islanded areas during a major disturbance (such as loss of multiple 500 kV lines along a common 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 (WECC 2001).
- 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.
- California Public Utilities Commission (CPUC) General Order 95 (GO-95), “Rules for Overhead Electric Line Construction,” formulates uniform requirements for

construction of overhead lines. Compliance with this order ensures adequate service and safety to persons engaged in the construction, maintenance and operation or use of overhead electric lines and to the public in general.

- CA ISO Planning Standards also provide standards, and guidelines to assure the adequacy, security and reliability in the planning of the CA ISO transmission grid facilities. The CA ISO Planning Standards incorporate the merged NERC and WECC Planning Standards. With regard to power flow and stability simulations, the CA ISO Planning Standards are similar to NERC/WECC and the NERC Planning Standards for Transmission System Contingency Performance. However, the CA ISO Standards also provide some additional requirements that are not found in the NERC/WECC or NERC Planning Standards. The CA ISO Standards apply to all participating transmission owners interconnecting to the CA ISO controlled grid. It also applies when there are any impacts to the CA ISO grid due to facilities interconnecting to adjacent controlled grids not operated by the CA ISO (CA ISO 2002a).
- CA ISO/FERC Electric Tariff provides guidelines for construction of all transmission additions/upgrades (projects) within the CA ISO controlled grid. The CA ISO determines the “Need” of the proposed project where it will promote economic efficiency or maintain System Reliability. The CA ISO also determines the Cost Responsibility of the proposed project and provides an Operational Review of all facilities that are to be connected to the CA ISO grid.

TSE ATTACHMENT 2: DEFINITION OF TERMS

ACSR	Aluminum Cable Steel Reinforced.
SSAC	Steel Supported Aluminum Conductor
AAC	All Aluminum conductor.
ADR	Alternative Dispute Resolution
Ancillary Services Market	The market for services other than scheduled energy that are required to maintain system reliability and meet WSCC/NERC operating criteria. Such services include spinning, non-spinning, replacement reserves, regulation (AGC), voltage control and black start capability.
Ampacity (Amps)	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.
Amperes or Amps	The unit of measure of electric current; specifically, a measure of the rate of flow of electrons past a given point in an electric conductor such as a power line.
Available Transmission Capacity (i.e., ATC)	Available Transmission Capacity in any hour is equal to Operational Transmission Capacity for that hour minus Existing Transmission Contracts for that same hour (ATC = OTC - ETC). (See the other definitions below).
Breaker	Circuit breaker - An automatic switch that stops the flow of electric current in a suddenly overloaded or otherwise abnormally stressed electric circuit.
Bundled Conductor	Two or more wires, connected in parallel through common switches, that act together to carry current in a single phase of an electric circuit.
Bus	Conductors that serve as a common connection for multiple transmission lines.
CA ISO	California Independent System Operator - The CA ISO is the FERC regulated control area operator of the CA ISO transmission grid. Its responsibilities include providing non-discriminatory access to the grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The CA ISO has no affiliation with any market participant.

CA ISO Controlled Grid	The combined transmission assets of the Participating Transmission Owners (PTOs) that are collectively under the control of the CA ISO.
CA ISO Reliability Criteria	Reliability standards established by the NERC, WSCC, and the ISO, as amended from time to time, including any requirements of the NRC.
CA ISO Planning Process	Annual studies conducted by the PTO's and CA ISO in an open stakeholder process. These studies determine the future transmission reinforcements necessary to enable the ISO Controlled Grid to meet the ISO Reliability Criteria. The CA ISO Planning Process also includes studies of new resource connections and third party proposals for new additions to the ISO Controlled Grid.
CA ISO Tariff	Document filed with the appropriate regulatory authority (FERC) specifying lawful rates, charges, rules, and conditions under which the utilities provide services to parties. A tariff typically includes rate schedules, list of contracts, rules, and sample forms.
Capacitor	An electric device used to store charge temporarily, generally consisting of two metallic plates separated by a dielectric.
Cogeneration	The consecutive generation of thermal and electric or mechanical energy.
Conductor	The part of the transmission line (the wire) which carries the current.
Congestion	The condition that exists when market participants seek to dispatch in a pattern which would result in power flows that cannot be physically accommodated by the system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based on requested/desired schedules.
Congestion Management	Congestion management is a CA ISO scheduling protocol that is used to resolve Congestion.
Contingency	Disconnection or separation, planned or forced, of one or more components from the electric system.
Day-Ahead Market	The forward market for the supply of electrical power at least 24 hours before delivery to Buyers and End-Use Customers.
Demand	Load plus any exports from an electric system.

Demand Forecast	An estimate of demand (electric load) over a designated period of time.
Dispatch	The operating control of an integrated electric system to: (i) assign specific generators and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises of falls; (ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; (iii) operate interconnections (iv) manage energy transactions with other interconnected Control Areas; and (v) curtail Demand.
dV/dQ	The partial derivative of the voltage at a bus with respect to the reactive injection at that bus. (See any elementary college calculus text for further discussion of partial derivatives.) The point at which dV/dQ approaches infinity is defined as the point of voltage collapse.
Emergency Condition	The system condition when one or more system elements are forced (not scheduled) out of service.
Emergency Overload	Loading of a transmission system element above its Emergency Rating during an Emergency Condition.
Emergency Rating	A special rating established for short-term use in the event of a forced line or transformer outage (e.g., an emergency). An emergency rating may be expressed as a percentage of the normal rating (e.g., 115 percent of normal) or as an elevated current rating. For example, the normal rating for a conductor may be 1000 amperes and the emergency rating may be 1100 amperes.
Excessive Voltage Deviation	A sudden change in voltage at any substation as a result of a Contingency that exceeds established allowable levels of change.
Existing Transmission Contract (i.e., ETC)	A contract for transmission services that was in place prior to the start of ISO operations.
Fault Duty	The maximum amount of short-circuit current which must be interrupted by a given circuit breaker.
FERC	Federal Energy Regulatory Commission
General Order 95	California Public Utilities Commission (CPUC) General Order which specifies transmission line clearance requirements.
Generation Outlet Line	Transmission facilities (circuit, transformer, circuit

	breaker, etc.) linking generation to the main grid.
Generation Tie	Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation to the main grid.
Generator	A machine capable of converting mechanical energy into electrical energy.
Heat Rate	The amount of energy input to an electric generator required to obtain a given value of energy output. Usually expressed in terms of British Thermal Units per kilowatt hour (Btu/kWh).
Hour-Ahead Market	The electric power futures market that is established 1-hour before delivery to End-Use Customers.
Imbalance Energy	Energy not scheduled in advance that is required to meet energy imbalances in real-time. This energy is supplied by Participating Generators under the CA ISO's control, providing spinning and non-spinning reserves, replacement reserves, and regulation, and other generators able to respond to the CA ISO's request for more or less energy.
Interconnected System Reliability	See Reliability.
Kcmil or kcm	One thousand circular mils. A unit of the conductor's cross sectional area which, when divided by 1,273, gives the area in square inches.
kV	Kilovolt - A unit of potential difference, or voltage, between two conductors of a circuit, or between a conductor and the ground.
Load	The rate expressed in kilowatts, or megawatts, at which electric energy is delivered to or by a system, or part of a system to end use customers at a given instant or averaged over an designated interval of time. (Also see Demand.)
Load Factor	The average Load over a given period (e.g., one year) divided by the peak Load in the period.
Loop	An electrical connection where a line is opened and a new substation is inserted into the opening. A looped configuration creates two lines, one from each of the original end points to the new substation. A looped configuration is more reliable than a tap configuration because the looped configuration provides two lines into the substation rather than just one in a tap configuration. Also, see Tap below.

Low Voltage	Voltage at any substation that is below the minimum acceptable level.
Marginal Unit	The Generator (or Load) that sets the market clearing price in the ISO's Ancillary Services Market (or the Power Exchange's energy market). The marginal unit is the Generator or Load that had the highest accepted bid for energy or Demand reduction.
MVAr	Megavar - One megavolt ampere reactive (a measure of reactive power). Reactive power demand is generally associated with motor loads and generation units or static reactive sources must supply this demand in the system.
MVA	Megavolt ampere - A unit of apparent power: equal to the product of the line voltage in kilovolts, the current in amperes, and the square root of 3 divided by 1000.
MW	Megawatt - A unit of power equivalent to 1,341 horsepower.
NERC	North American Electric Reliability Council
Nominal Voltage	Also known as Normal Voltage. The voltage at which power can be delivered to loads without damage to customer equipment or violation of CA ISO Reliability Criteria when the system is under Normal Operation.
Normal Operation	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.
NRC	Nuclear Regulatory Commission
N-1 Contingency	A forced outage of one system element (e.g., a transmission line or generator).
N-2 Contingency	A forced outage of two system elements usually (but not exclusively) caused by one single event. Examples of an N-2 Contingency include loss of two transmission circuits on a single tower line or loss of two elements connected by a common circuit breaker due to the failure of that common breaker.
Operational Transfer Capability (i.e., OTC)	The maximum amount of power which can be reliably transmitted over an electrical path in conjunction with the simultaneous reliable operation of all other paths. This limit is typically defined by seasonal operating studies, and should not be confused with a path rating. Also referred to as

	OTC.
Outlet	Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation to the main grid.
Participating Generator	A generator that has signed an agreement with the CA ISO to abide by the rules and conditions specified in the CA ISO Tariff.
Participating Transmission Owner (i.e., PTO)	A Participating Transmission Owner is an electric transmission owning company that has turned over operational control of some or all of their electric transmission facilities to the CA ISO. Currently, the three Participating Transmission Owners are PG&E, SCE, and SDG&E.
Path Rating	The maximum amount of power which can be reliably transmitted over an electrical path under the best set of conditions. Path ratings are defined and specified in the WSCC Path Rating Catalog.
PG&E	Pacific Gas & Electric Company
PG&E Interconnection Handbook	Detailed instructions to new customers (either load or generation) on how to interconnect to the PG&E electric system.
Post-Transient Voltage Deviation	The change in voltage from pre-contingency to post-contingency conditions once the system has had time to readjust.
Power Flow	A generic term used to describe the type, direction, and magnitude of actual or simulated electrical power flows on electrical systems.
Power Flow Analysis	A power flow analysis is a forward looking computer simulation of all major generation and transmission system facilities that identifies overloaded circuits, transformers and other equipment as well as system voltage levels under both Normal and Emergency Conditions.
Pump	A hydroelectric generator that acts as a motor and pumps water stored in a reservoir to a higher elevation.
Q/V Curve	A graphical representation of the voltage a given substation bus as a function of the reactive injection at that bus.
RAS	Remedial Action Scheme - An automatic control provision (e.g., trip a generation unit to mitigate a circuit overload).

Reactive Power	The portion of apparent power that does no work in an alternating current circuit but must be available to operate certain types of electrical equipment. Reactive Power is most commonly supplied by generators or by electrostatic equipment, such as shunt capacitors.
Reactive Margin	Reactive Power must be available at all load buses to prevent voltage collapse. Reactive margin is the amount of additional reactive load, usually measured in MVAR's, which may be added at a particular bus before the system experiences voltage collapse.
Reactor	An electric device used to store electric current temporarily, generally consisting of a coil of wire wound around a magnetic core.
Real Power	Real power is the work-producing component of apparent power and is required to operate any electrical equipment that performs energy conversion. Examples of this electrical equipment would be a heater, a lamp, or a motor. Real power is usually metered in units of kilowatt-hours (kWh).
Real-Time Market	The competitive generation market controlled and coordinated by the CA ISO for arranging real-time imbalance power.
Reconductoring	The removal of old conductors on a transmission or distribution line followed by replacement of these conductors with new higher capacity conductors.
Reliability	The degree of performance of the elements of the electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. May be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.
Reliability Criteria	Principals used to design, plan, operate, and assess the actual or projected reliability of an electric system.
Reliability Must-Run (i.e., RMR)	The minimum generation (number of units or MW output) required by the CA ISO to be on line to maintain system reliability in a local area.

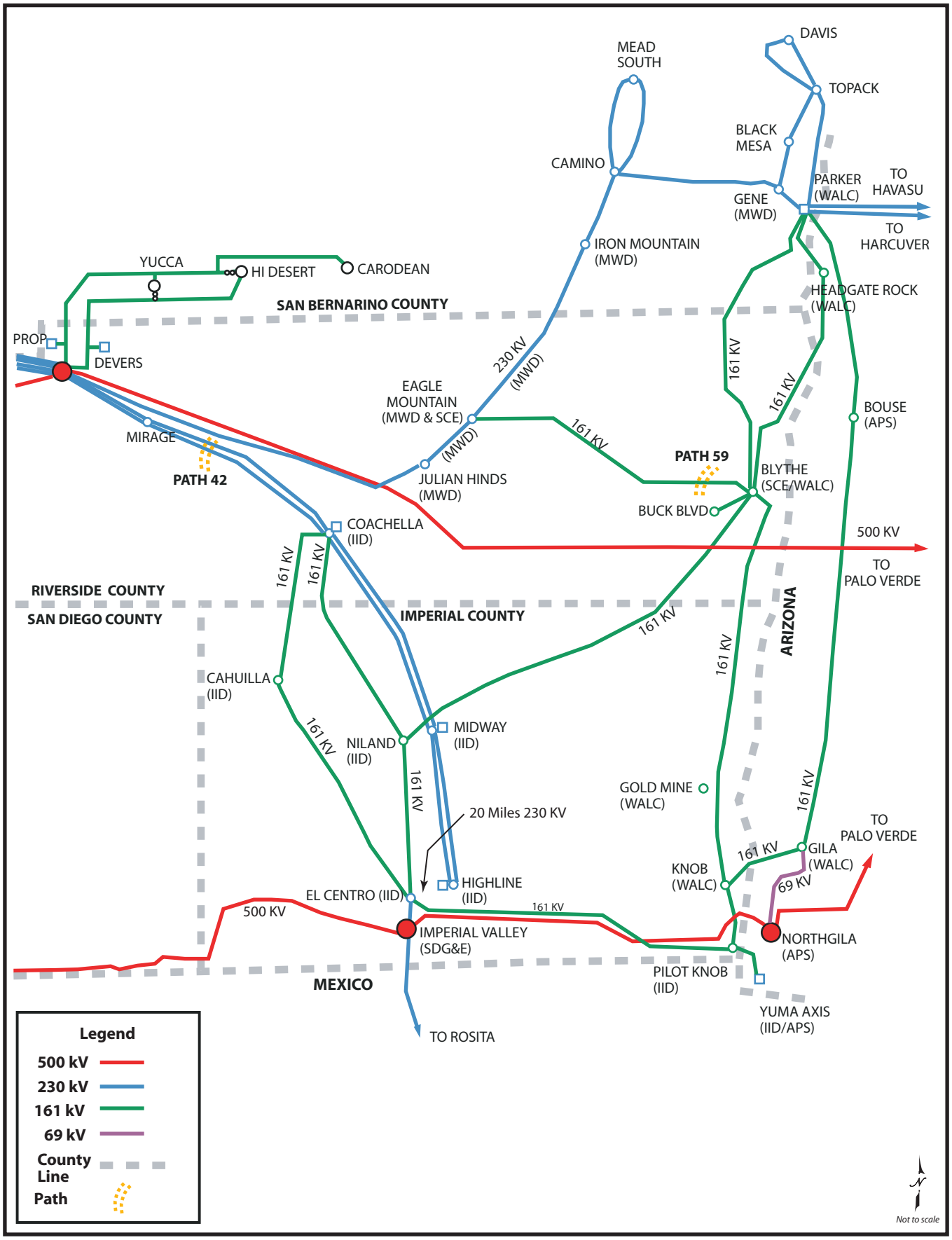
SCE Transmission Owner Tariff	Provides guidelines to interconnect SCE System to a generator or to construct transmission expansions and facilities upgrades.
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
Sensitivity Study	An analysis to determine the impact of varying one or more parameters on the results of the original analysis.
Series Capacitor	A static electrical device that is connected in-line with a transmission circuit that allows for higher power transfer capability by reducing the circuit's overall impedance.
Shunt Capacitor	A static electrical device that is connected between an electrical conductor and ground. A shunt capacitor normally will increase the voltage on a transmission circuit by providing reactive power to the electrical system.
Single Contingency	See N-1 Contingency.
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.
Source or Sink of Reactive Power	A source of Reactive Power is a device that injects reactive power into the power system (e.g., a Generator or a Capacitor). A sink of Reactive Power absorbs reactive power from the power system. Examples of reactive power sinks are shunt Reactors and motor loads.
Static Compensator	StatCom - a shunt connected power system device that includes Capacitors and Reactors controlled by solid state electronic devices as opposed to mechanically operated switches.
Substation	An assemblage of equipment that switches, changes, or regulates voltage in the electric transmission and distribution system.
Switchyard	A substation that is used as an outlet for one or more electric generators.
Switched Reactive Devices	A shunt Capacitor or shunt Reactor controlled by mechanically operated switches.
Switching Station	Similar to a substation, but there is only one voltage level.

Synchronous Condenser	A rotating mechanical device very similar to a Generator. The Synchronous Condenser has no mechanical power input and cannot produce Real Power. It can only produce or absorb Reactive Power.
System Reliability	See “Reliability”.
Tap	An electrical connection where a new line is connected to an intermediate point on an existing transmission line and a new substation is connected to the end of the new line. A tapped configuration creates a single transmission circuit with more than two end points (for example, a “T”). A tapped configuration is less reliable than a looped configuration because a fault on any portion of the tapped circuit causes a complete loss of power to the new substation. Also, see Loop above.
Tap Changing Transformer	A Transformer that has the ability change the number of windings in service. By changing the number of windings in service (by moving to a different tap), the Tap Changing Transformer has the ability to maintain a nearly constant voltage at its output terminals even though the input voltage to the Transformer may vary.
Thermal Loading Capability	The current-carrying capacity (in Amperes) of a conductor at specified ambient conditions, at which damage to the conductor is non-existent or deemed acceptable based on economic, safety, and reliability considerations.
Thermal overload	A thermal overload occurs when electrical equipment is operated in excess of its current carrying capability. Overloads are generally given in percent. For example, a transmission line may be said to be loaded to 105 percent of its rating.
Thermal rating	See Ampacity.
Transformer	A device that changes the voltage of alternating current electricity.
Transformer Loading Capability	The current-carrying capacity (in Amperes) of a transformer at specified ambient conditions, at which damage to the transformer is non-existent or deemed acceptable based on economic, safety, and reliability considerations.
TSE	Transmission System Engineering.
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.
Undercrossing	A transmission configuration where a transmission line crosses below the conductors of another transmission line, generally at 90 degrees.
VAr	One Volt ampere reactive. Also see the definition for MVAr.
Voltage	Electromotive force or potential difference.
Voltage Collapse	The point at which the reactive demand at a substation bus exceeds the reactive supply at that bus. When the reactive demand is greater than the supply, the voltage at that point in the system will drop. Eventually, the voltage will drop to a point at which it is no longer possible to serve load at that bus.
Wheeling	A service provided by an entity, such as a utility, that owns transmission facilities whereby it receives electric energy into its system from one party and then uses its system to deliver that energy to a third party. The wheeling entity is usually paid a fee for this service.
WESTERN	Western Area Power Administration
WATTS	Western Arizona Transmission System Task Force
WECC	Western Electric Coordinating Council

TRANSMISSION SYSTEM ENGINEERING - FIGURE 1

Blythe Energy Project Phase II - Existing Transmission System Blythe Area

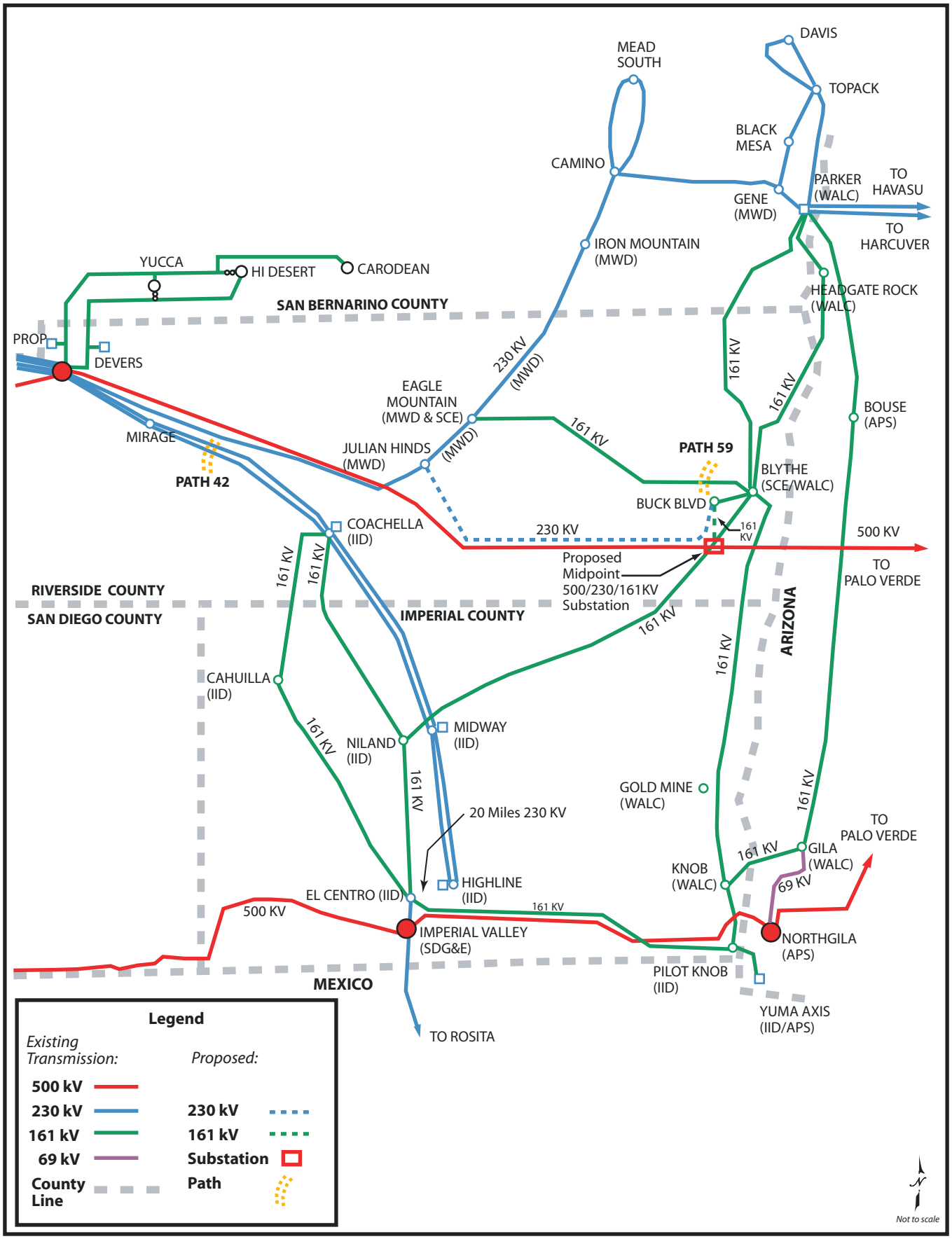


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: SCE and CEC Staff

TRANSMISSION SYSTEM ENGINEERING - FIGURE 2

Blythe Energy Project Phase II - Existing Transmission System and Proposed BEPTL Projects in Blythe Area

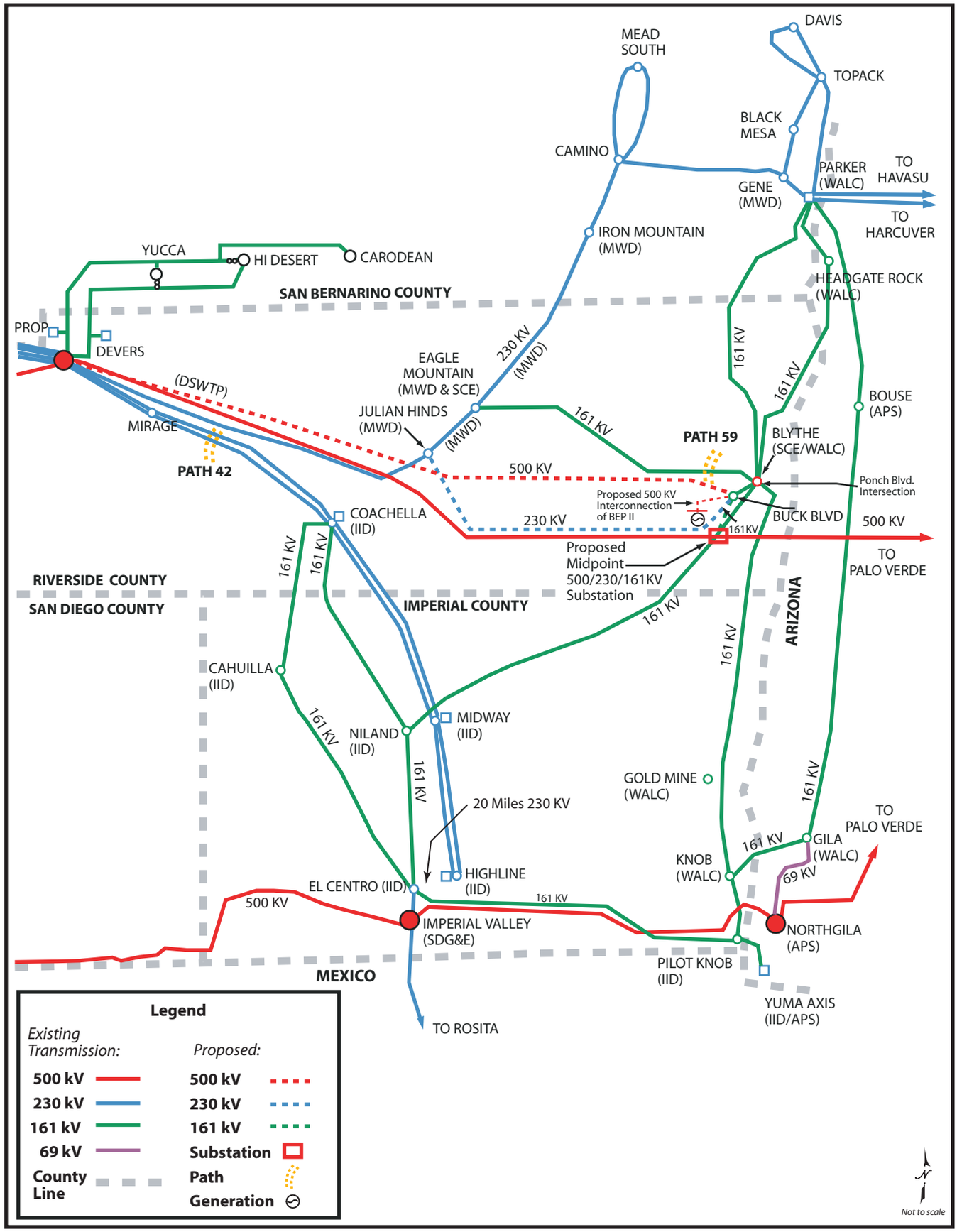


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: SCE and CEC Staff

TRANSMISSION SYSTEM ENGINEERING - FIGURE 3

Blythe Energy Project Phase II - Existing Transmission System, Proposed BEPTL Projects and Blythe II Interconnection with DSTWP 500 KV Line in Blythe Area

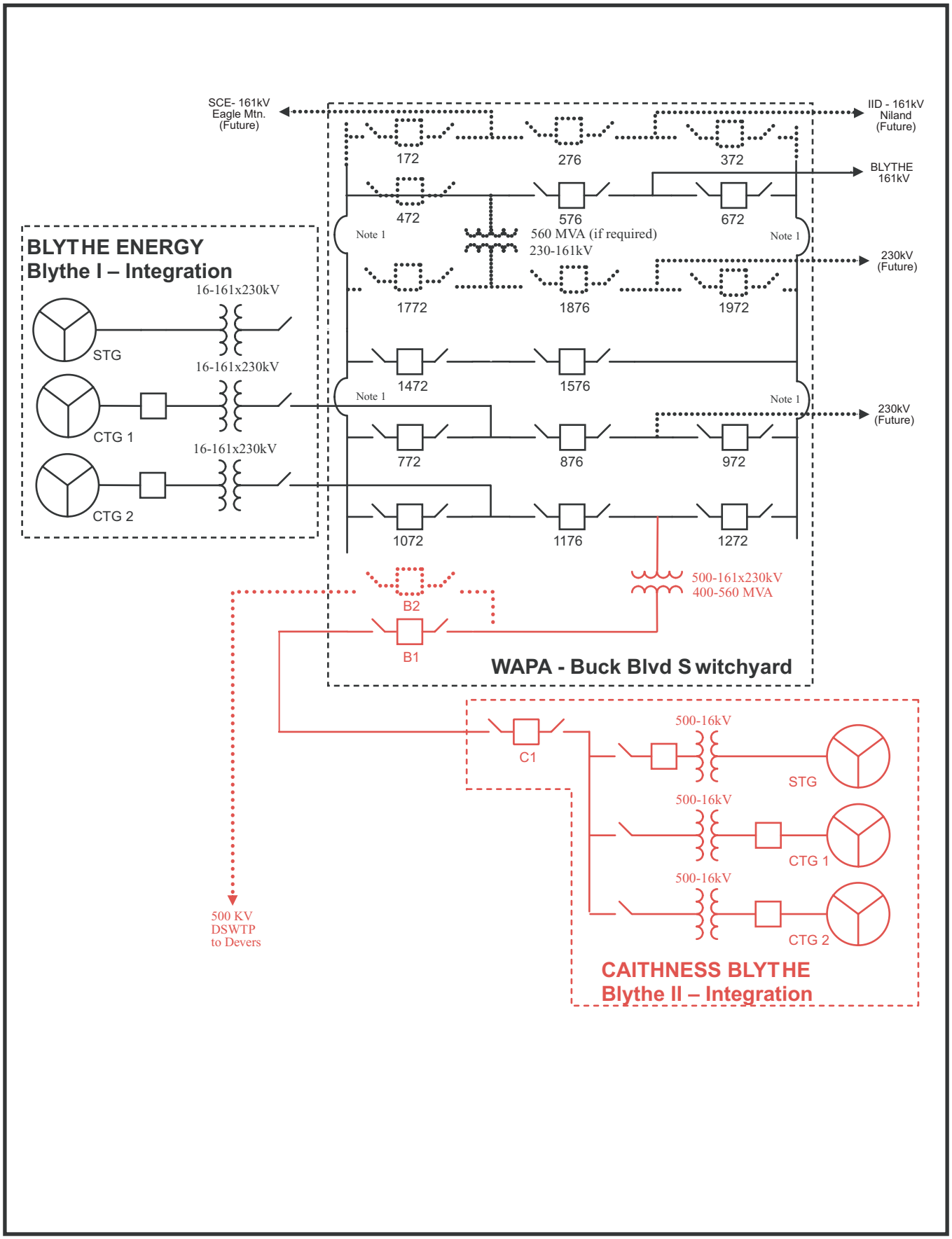


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: SCE and CEC Staff

TRANSMISSION SYSTEM ENGINEERING - FIGURE 4

Blythe Energy Project Phase II - Proposed Interconnection Facilities

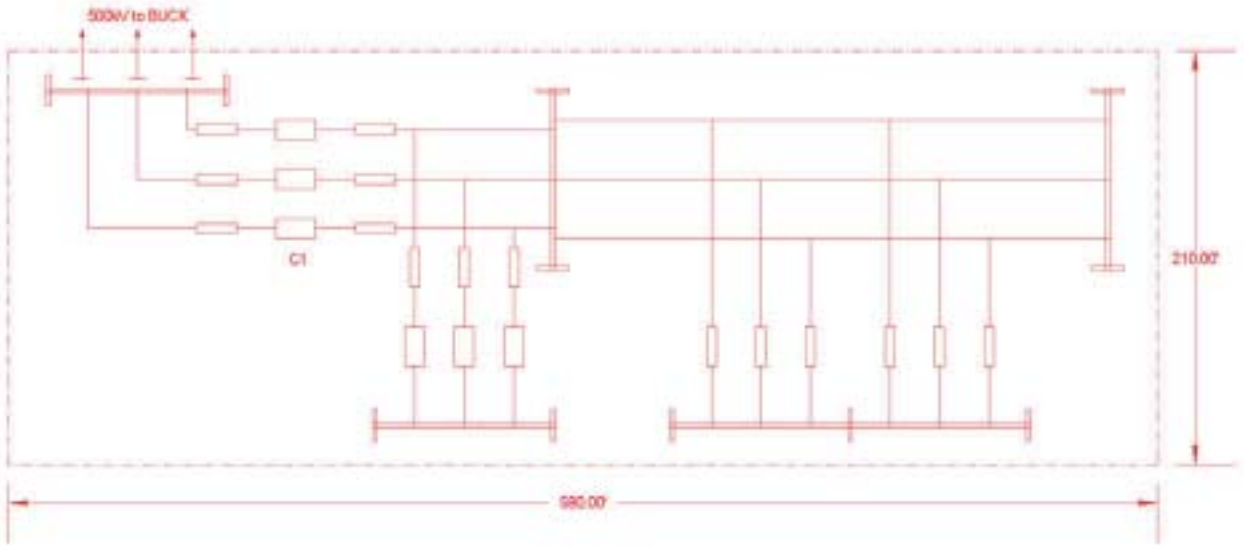


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: Blythe Area Regional Transmission Study (Draft), July 2003, Revised by CEC Staff.

TRANSMISSION SYSTEM ENGINEERING - FIGURE 5

Blythe Energy Project Phase II - Integration Switchyard, General Layout



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, MARCH 2005

SOURCE: Blythe Area Regional Transmission Study (Draft), July 2003.

ALTERNATIVES

Testimony of Susan V. Lee

SUMMARY OF CONCLUSIONS

In the analysis of individual resource areas, the FSA finds potential adverse impacts of the proposed Blythe Energy Project Phase II (BEP II) on water and soil resources, traffic and transportation, land use, biological resources, and transmission systems engineering. Based on these and other concerns, four alternative power plant sites are considered in this section. Three sites are in the Blythe area (Blythe Airport Site, Interstate 10 (I-10) Site, and South of Blythe Site), and one site is adjacent to the Devers Substation north of Palm Springs.

Significant impacts are identified in this FSA concerning aviation safety due to BEP II's proximity to Blythe Airport, the lack of adequate cooling water, the lack of data on transmission system engineering, and potential significant effects on migratory birds at the proposed evaporation ponds. Therefore, each alternative site is evaluated for its ability to reduce or eliminate those impacts, while not creating new significant unmitigable impacts of its own. The construction of BEP II adjacent to the existing operating power plant (BEP I) offers the following advantages over any alternative: (1) reduction of the need to construct or develop redundant facilities or additional linear components; and (2) the BEP II power plant would be constructed on land already disturbed and evaluated for the original BEP I, for which desert tortoise mitigation has already been provided.

Overall, the four site alternatives considered in this section offer some advantages and disadvantages in comparison to the proposed project. All four sites have the same challenges with respect to biological impacts from migratory bird use of evaporation ponds; that concern could be resolved at each site with use of zero liquid discharge systems or other mitigation strategies. The three Blythe area sites would all have the same uncertainties as the proposed project with respect to transmission availability.

In conclusion, the Interstate 10 Site has the best potential for reducing or eliminating the significant impacts of the proposed project, and no significant impacts have been identified. The South of Blythe Site is less advantageous due to the proximity of residences to the site, but no significant impacts have been identified at that site. The Blythe Airport Site would have the same inconsistencies with Laws, Ordinances, Regulations and Standards (LORS) resulting from proximity to the airport that occur with the proposed BEP II site, and the Devers Site would require rezoning, which is considered a significant impact.

INTRODUCTION

This section considers potential alternatives to the construction and operation of Caithness' proposed BEP II. 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 require Caithness Blythe II, L.L.C. (Caithness) 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. The Energy Commission may, however, refuse to certify the project as proposed, in light of potential significant adverse impacts, and may allow the applicant to seek certification at a different site. Implementation of an alternative site would require that the applicant submit a new Application for Certification (AFC), or modify the existing AFC, depending upon the extent of the changes, and revise the engineering and environmental analyses. 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. Preparation and review of a new AFC would require additional time.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Caithness proposes to interconnect the proposed BEP II to the new Buck Boulevard Substation, which is under the jurisdiction of the Western Area Power Administration (Western). Since Western is a federal agency, the BEP II 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.

CALIFORNIA ENVIRONMENTAL QUALITY ACT CRITERIA

The “Guidelines for Implementation of the California Environmental Quality Act,” Title 14, California Code of Regulation, Section 15126.6(a), provides direction by requiring an evaluation of the comparative merits of “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project.” In addition, the analysis must address the “no project” alternative (Cal. Code Regs., tit. 14, §15126.6(e)).

The range of alternatives is governed by the “rule of reason” which requires consideration only of those alternatives necessary to permit informed decision-making and public participation. CEQA states that an environmental document does not have to consider an alternative of which the effect cannot be reasonably ascertained and of which the implementation is remote and speculative (Cal. Code Regs., tit. 14, §15125(d)(5)).

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 (EIS).

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 BEP II would be a nominal 520 megawatt (MW) natural gas fired generating facility located on approximately 15 to 20 acres within a 76-acre parcel. The site is located to the east of the Blythe Airport, which is owned by Riverside County and operated by the City of Blythe and is immediately adjacent to the Blythe Energy Phase I (BEP I) power plant, which is owned by Blythe Energy, L.L.C., a subsidiary of Florida Power and Light (FPL), and commenced commercial operation in December 2003. The City of Blythe, centered five miles to the west, annexed and incorporated the project site within the City limits. The land is currently zoned for industrial uses (BEP II 2002a). The BEP II would include equipment identical to the Blythe Energy Phase I facility, but the two projects would not be related in any other way. They would share only a stormwater retention pond and electrical substation.

BEP II, as proposed, would rely on groundwater derived from two additional groundwater wells, similar to the two wells currently being used by BEP I, each well having the capacity to pump up to 3,000 gallons per minute (gpm) of cooling water for the project's proposed wet (evaporative) cooling system. BEP II would duplicate supply and wastewater treatment systems constructed as part of BEP I. A 6-acre evaporation pond is proposed to be constructed for BEP II, adding to the two ponds constructed for BEP I. The pond would be subject to the conditions established by the Regional Water Quality Control Board. However, as identified in the Biological Resources analysis, to prevent a significant impact to federally-protected migratory birds, BEP II will need to redesign its project to either eliminate the evaporation ponds or provide a system, such as zero-liquid discharge (ZLD) to guarantee that birds will not feed in, nest near, or use these potentially toxic bodies of water in any way. Additional emergency backup water from BEP I would be used if required due to problems with the on-site wells. In addition to the cooling of the steam turbine exhaust, the applicant proposes to use an inlet air chilling system, requiring use of anhydrous ammonia, to cool the air entering the gas turbines in order to improve the efficiency and capacity of the gas turbines, particularly under conditions of high ambient temperature. Anhydrous ammonia is a hazardous material; its proposed use is discussed in the **HAZARDOUS MATERIALS** section of this report.

A Water Conservation Offset Plan (WCOP) has been proposed by the BEP II applicant to comply with anticipated Bureau of Reclamation requirements. The WCOP lacks necessary specifics, and staff does not believe it will mitigate the project's water use, nor was it proposed as a mitigation measure; therefore, there are still outstanding issues and potentially significant impacts related to the water source for BEP II that are discussed in greater detail below.

The proposed power plant would require no offsite natural gas pipelines. Natural gas for the facility would be delivered via the gas pipeline constructed as part of BEP I. As currently proposed, a 500-kV transmission line would connect BEP II to an expanded Buck Boulevard Substation, requiring a significant enlargement of the existing substation, which was constructed as part of BEP I. From the expanded Buck Boulevard Substation, the BEP II project would connect to the grid via either the Desert Southwest Transmission Line Project (DSWTP) or using another interconnection that has not yet been defined.

The DSWTP is a proposed new 118-mile 500-kV transmission line that would be constructed to the Devers Substation. The DSWTP is currently undergoing a separate environmental review by the Imperial Irrigation District's (IID) and the U.S. Bureau of Land Management (BLM). The DSWTP Draft EIS/Environmental Impact Report (EIR) was published in 2003. There is no estimate of when a Final EIS/EIR will be published (BLM, 2005). The IID proposed transmission line is not part of the proposed BEP II project. However, due to the delay in publication of the DSWTP Final EIS/EIR, the construction of the new DSWTP line in a timely manner before the projected on-line date of the BEP II plant (summer 2006 per applicant's AFC) is infeasible.

As also discussed under the **TRANSMISSION SYSTEM ENGINEERING** section of this FSA, the sponsors of the proposed DSWTP line are negotiating with Southern California Edison (SCE) so that the DSWTP could become a part of the SCE-sponsored Devers-Palo Verde 500 kV No. 2 (DPV2) line between Blythe and Devers (see Other Transmission Projects in the Region below). The target date for completion of the DPV2 line by SCE is now 2009, which staff believes is uncertain.

Consequently the feasibility of the BEP II project also remains uncertain. Staff has requested that the applicant submit new System Impact Studies (SIS), Facility Studies (FS), and a final feasible Interconnection plan and transmission option using updated modeling assumptions and system assumptions (see **TRANSMISSIONSYSTEM ENGINEERING** section of this FSA). Staff must have this information to determine if the transmission system engineering of the project conforms with LORS. Moreover, until the SIS is secured, downstream system reliability impacts and environmental impacts cannot be identified. Regardless, this Staff Assessment has considered the 500-kV transmission line project in the IID EIS/EIR, and not any of the alternatives due to lack of interconnection and system impact information.

The Blythe Substation, located across Hobsonway directly to the east of the proposed project, interconnects five existing 161-kV regional transmission lines. Three transmission lines are owned by Western, one by IID, and the other by SCE. As with Buck Boulevard Substation, a system impact study would be necessary to determine technical and economic feasibility of the interconnection to Blythe Substation. Other

proposed transmission projects in the region that could possibly serve as interconnections are discussed in the following section.

OTHER TRANSMISSION PROJECTS IN THE REGION

In addition to the DSWTP project discussed above, two other transmission projects are currently proposed in the Blythe area: Blythe Energy Project Transmission Line (BEPTL) Project and the Devers-Palo Verde 500 kV No. 2 (DPV2) Project.

BLYTHE ENERGY PROJECT TRANSMISSION LINE PROJECT

Blythe Energy LLC, owner of BEP I, submitted a Petition for a Post-Certification Amendment (99-AFC-8) in October 2004 and is proposing transmission line modifications that would allow more of the electrical output from BEP I to be delivered to the southern California ISO-controlled electrical transmission system. The Energy Commission staff's Preliminary Staff Assessment for the BEPTL Project was published in January 2005 for the following two distinct project components. Blythe Energy, LLC (BEP I) is requesting approval of both components but may opt to construct only one or the other.

- **Buck Boulevard to Julian Hinds Transmission Line Component**: Installation of approximately 67.4 miles of new 230 kilovolt (kV) single-circuit transmission line between the Buck Boulevard Substation and the Julian Hinds Substation (approximately sixty miles to the west). The proposed transmission line route would generally follow SCE's existing 500 kV Devers-Palo Verde (DPV) transmission line.
- **Buck Boulevard to Devers-Palo Verde Transmission Line Component:** Installation of approximately 6.7 miles of a new 230-kV single-circuit transmission line (initially operated at 161 kV) between the Buck Boulevard Substation and SCE's existing DPV 500-kV transmission line, mostly adjacent to an existing IID 161-kV transmission line. In addition, the project would include construction of a new 161-kV to 500-kV substation ("Midpoint Substation") at the point of interconnection with SCE's existing DPV 500-kV transmission line.

DEVERS-PALO VERDE 500-KV NO. 2 PROJECT

The Devers-Palo Verde 500 kV No. 2 Project (DPV2) as proposed by Southern California Edison (SCE) includes a 230-mile new 500-kV line from the Harquahala Substation (in Arizona, near the Palo Verde nuclear power plant) to SCE's Devers Substation (in North Palm Springs, California). The project also includes upgrades to an additional 50 miles of 230 kV lines west of the Devers Substation. The 500-kV portion would be within or immediately adjacent to SCE's existing DPV No. 1 right-of-way (ROW). This project may also include the construction of a new Midpoint Substation in the Blythe area, as is also proposed under BEPTL.

This project was approved by the California Independent System Operator (CAISO) in February 2005, and an application for a Certificate of Public Convenience and Necessity was submitted to the CEQA lead agency, the California Public Utilities Commission (CPUC) on April 11, 2005. The CPUC's environmental review of the project will be coordinated with the U.S. Bureau of Land Management (BLM) as the lead agency under NEPA, and is underway.

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.

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. 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 (BEP II 2002a):

- The site is adjacent to BEP I;
- The site is in close proximity to existing electrical transmission and natural gas facilities;
- Sufficient land is available;
- The site has environmental compatibility with an expected low impact on the environment, given its proximity to the industrial lands at the airport and BEP I, remoteness from residential areas, elevation above most populated areas, and low traffic conditions; and
- The parcel is located in a designated corridor targeted for industrial development.

In preparation of this alternatives analysis, staff used the following methodology:

1. Provide an overview of the project, identify the basic objectives of the project, and describe its potentially significant adverse impacts.
2. Review the applicant's site selection criteria.
3. Identify and evaluate technology alternatives to the project such as increased energy efficiency (or demand side management) and the use of alternative technologies (e.g. wind, solar, or geothermal energy).
4. Identify and evaluate alternative locations or sites.
5. Evaluate the impacts of not constructing the project, known as the "no project" alternative under CEQA.

For purposes of its Draft Environmental Assessment (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 were found not to be consistent with Western's purposes and need and were dismissed from the full analysis for purposes of Western's Draft 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 Draft EA.)

PROJECT OBJECTIVES

Based on analysis of the BEP II 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;
- Location near a substation and key infrastructure for natural gas, water supply and transmission lines;
- Generation of approximately 520 MW of electricity.

While the applicant also included an objective of co-location with BEP I to minimize operational and maintenance costs, staff felt it important to the analysis to explore other possible sites. Therefore, staff did not utilize this objective when analyzing feasible alternatives.

NEPA PURPOSE AND NEED STATEMENT

NEED FOR WESTERN ACTION

Caithness has applied to interconnect with Western's transmission system at the Buck Boulevard Substation. Western must respond to Caithness' 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 the 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 its Final 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. Any differences will be presented in Western's Final EA.

POTENTIAL SIGNIFICANT ENVIRONMENTAL IMPACTS

In the PSA, staff identified the potential for significant environmental effects of the proposed project in the following technical areas (summarized below) and focused on developing alternatives to reduce or eliminate these potentially significant impacts: air quality, cultural resources, land use, biological resources, traffic and transportation, transmission system engineering, and water and soil resources. This FSA finds that there would still be potentially significant impacts related to land use inconsistencies, traffic and transportation conflicts with the airport, transmission system engineering, and water and soil resources.

Land Use. There are three land use issues that remain to be resolved. First, the Water Conservation Offset Program (WCOP) has the potential to cause significant adverse impacts to agricultural resources in the area and could be in conflict with County and City goals and policies that encourage retention of agricultural land. Second, the Riverside County Airport Land Use Commission (ALUC) has determined that the project is inconsistent with the *Comprehensive Land Use Plan for Blythe Airport, Riverside County, California (CLUP)*, while recommending conditions if the Commission decides to approve the project. The City has recommended that the Energy Commission override the ALUC's determination. Staff has recommended that the Energy Commission not override, but accept the ALUC's determination of inconsistency. Finally, the potential for land use compatibility impacts, including cumulative impact, of thermal plumes and visible water vapor plumes caused by the project are considered a potentially significant impact to pilots landing at Blythe Airport.

Traffic and Transportation. Concerns have been raised by local pilots and the airport facility operator regarding air traffic safety associated with thermal plumes generated by the existing BEP I facility. Staff asked the Caltrans Aeronautics Division to review the proposed BEP II project in terms of the proposed site location and potential plume-related aviation safety concerns. Caltrans Aeronautics has recommended that the BEP II project not be built at the proposed location due to airport safety concerns. The Energy Commission hired an aviation safety consultant to provide an independent assessment of this issue. The consultant concluded there would be potentially significant airport safety impacts if the BEP II plant were built at the proposed site. In addition, the Riverside Airport Land Use Commission (ALUC) determined that the proposed BEP II site is inconsistent with the Blythe Airport Comprehensive Land Use Plan. However, the Blythe City Council found that with mitigation, the BEP II project would comply with the Public Utilities Code, and unanimously voted to override the findings of the ALUC and support approval of BEP II at the proposed location. Staff believes the override was inappropriate because it did not mitigate the aviation safety issues related to BEP II operation, and the potential economic benefits to the area could be realized if the plant was built in another location in the City of Blythe.

Transmission System Engineering. Staff has evaluated the available system reliability studies and the applicant's description of the proposed project and has found that the studies are inadequate and the project definition is uncertain and likely infeasible. The studies provided do not comply with North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and CAISO

planning standards, and Western's Interconnection standards. The available information is not sufficient for staff to reach a finding on conformance with system reliability LORS or engineering LORS. Given the inadequate description of the project (i.e., the integration substation where the project would connect to the regional transmission system, Buck Boulevard Substation and its potential outlet lines connecting to unknown points) conditions of certification cannot be developed to confidently assure conformance with system reliability criteria and applicable engineering and safety LORS.

Water and Soil Resources. The applicant has proposed to supply water to operate the facility by installing two additional groundwater wells, each having the capacity to pump up to 3,000 gallons per minute. Staff determined that the project's use of groundwater from the Colorado River aquifer would contribute to a significant impact to the State's Colorado River water supply and its users. Staff also has concerns about the practical effectiveness of the proposed WCOP as mitigation. Staff believes that even if the WCOP is effectively implemented, it would not eliminate the project's unnecessary consumptive use of water from the Colorado River aquifer. Therefore, the WCOP in itself would not provide adequate mitigation and there would be nonconformance with LORS and significant cumulative impacts to the region's water supply.

In addition, many of the soils within the mesa and valley areas are listed as Prime Farmland and Highly Erodible Lands. Staff is concerned that if the lands are not properly managed, the proposed WCOP could result in significant degradation of the soils and agricultural productivity and soil loss via wind and water erosion.

Due to these potentially significant water usage concerns, staff analyzed the feasibility, potential impacts, and costs of three alternative cooling technologies that could be used at BEP II to reduce water usage. Staff determined in this FSA that dry cooling would be the preferred option. However, because dry cooling increases the potential for significant adverse impacts to planes utilizing the nearby Blythe Airport, staff cannot conclude that it is a feasible technology alternative at this site. Dry cooling and hybrid cooling using non-potable water for evaporative cooling or in conjunction with dry cooling air cooled condensers are fully evaluated in the Water Supply and Cooling Options study in Appendix A of this Staff Assessment, and therefore, are not analyzed in this section.

Biological Resources. As identified in the FSA Biological Resources section, the evaporation pond as designed in conjunction with the high levels of sodium and selenium are likely to cause on-going significant impacts to birds that cannot be mitigated to less than significant levels except through the elimination of any exposure. The project as proposed would violate the Migratory Bird Treaty Act and possibly violate Fish and Game Code 3503, 3503.5 and 3505. To mitigate the significant impact and non-conformance with LORS, staff is recommending that the project owner present a new design which incorporates a zero-liquid discharge to solids technology.

SITE ALTERNATIVES

Four alternative sites have been identified. The applicant presented two of these as part of its alternatives analysis (Alternative Site A - South of the City of Blythe Site and Site B - Blythe Airport Site; BEP II 2002a). Staff identified two additional potential alternative sites: the Interstate 10 Site and the Devers Site. All four sites were retained for analysis and are evaluated below. Please see **ALTERNATIVES Figures 1 and 2** for maps of these sites.

SCREENING CRITERIA USED TO SELECT ALTERNATIVE SITES

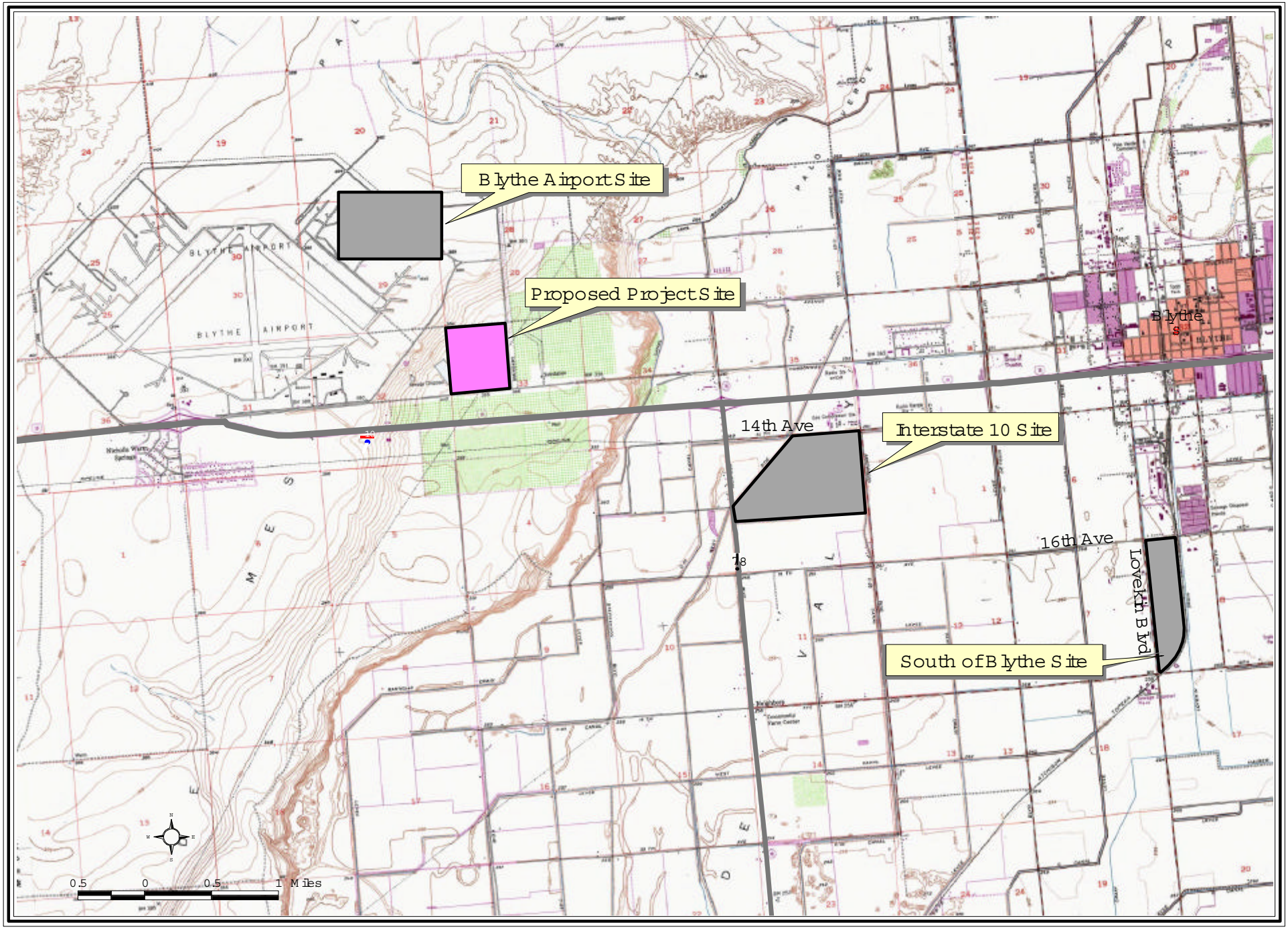
The following criteria were used to identify potential alternative sites. Each site was evaluated for its ability to:

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 regional grid system for 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 76 acres of land, however only 15-20 acres are required for a generating facility using the proposed technology (BEP II 2002a). Therefore, staff used 20 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 unmitigable impacts of its own.
4. Be sufficiently far from moderate or high density residential areas and sensitive receptors (such as schools and hospitals, and recreation areas).

The alternative site analyses focus on the disciplines for which impacts were initially identified for the proposed project in the PSA or subsequently identified in the FSA: land use, traffic and transportation, transmission system engineering, water and soil resources, biological resources, and cultural resources. In addition, air quality, visual resources, geological concerns, noise, and hazardous materials were considered where potentially significant impacts were identified in connection with an alternative site, or where there is a substantial difference between one site and the others.

ALTERNATIVES - FIGURE 1

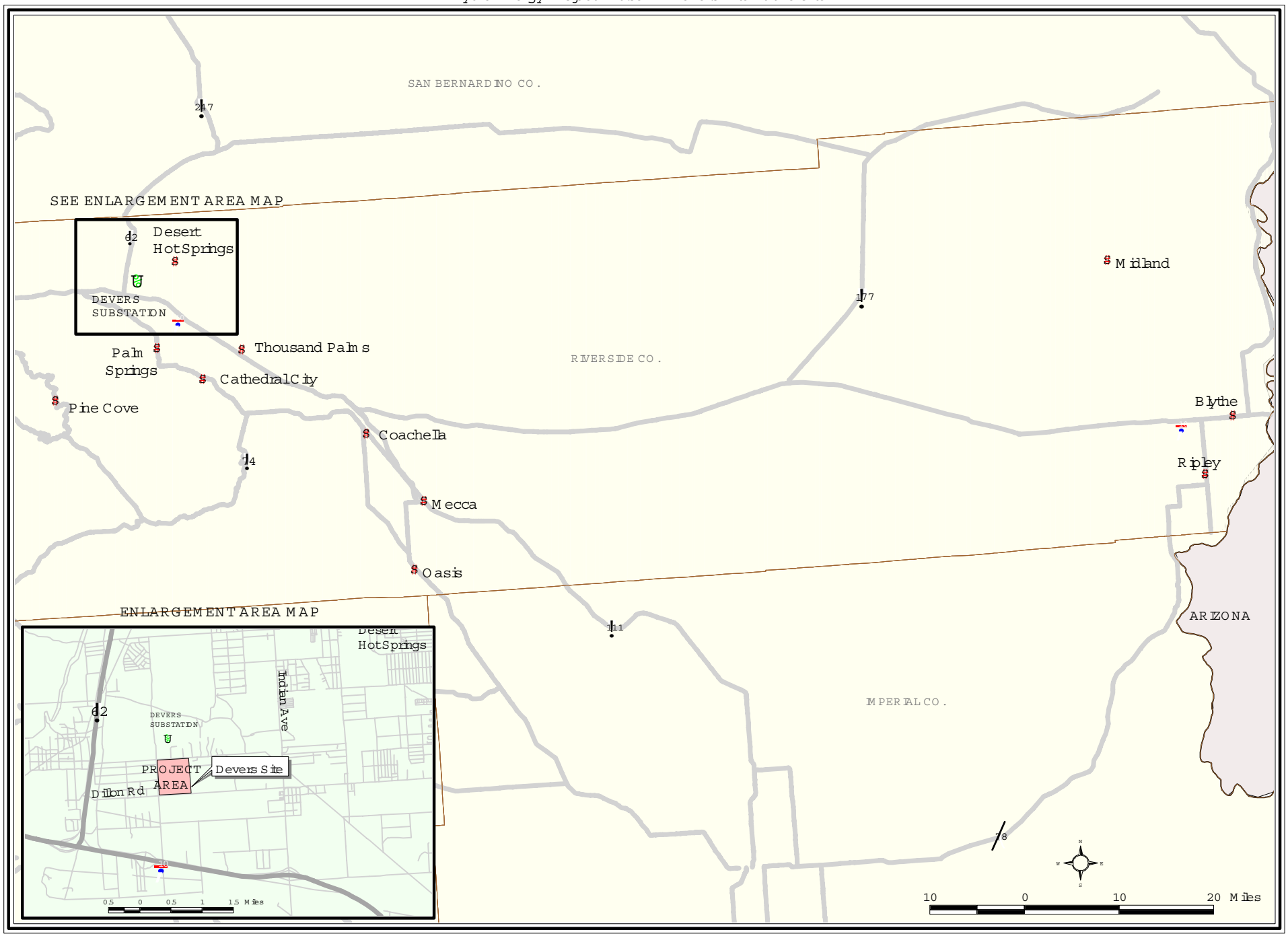
Blythe Energy Project Phase II - Alternative Sites



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005

SOURCE: California Energy Commission Statewide Transmission & Power Plant Maps 2003

ALTERNATIVES - FIGURE 2
Blythe Energy Project Phase II - Devers Alternative Site



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, APRIL 2005
SOURCE: California Energy Commission Statewide Transmission & Power Plant Maps 2003

SOUTH OF BLYTHE SITE

The South of Blythe Site (applicant's Alternative Site A) is located south of central Blythe in the Palo Verde Valley in unincorporated Riverside County. It is bordered to the north by 16th Avenue, to the south and east by the Atchison, Topeka, and Santa Fe Railroad line, and to the west by Lovekin Boulevard. The City of Blythe is planning on incorporating this area for development and zoning it for commercial and/or industrial uses. The site consists of approximately 150 acres of land. The site is currently in agricultural use and is surrounded by industrial and agricultural land uses.

The alternative could tie into the regional electrical grid at Western's Blythe Substation, approximately 5.5 miles to the northwest. Access to this substation would require the construction of overhead transmission lines along the agricultural lands of the Palo Verde Valley and up the east face of Palo Verde Mesa. An alternative transmission tie-in location could be at the future Midpoint Substation, which is proposed to be built under both the BEPTL and DPV2 projects and would allow interconnection to the existing or future SCE 500-kV transmission lines. This new substation would be located approximately five miles west of the South of Blythe site and would not require a crossing of I-10. Similar to the proposed project, water would likely be supplied via two groundwater wells and an on-site evaporation pond would be utilized. A natural gas pipeline would have to be constructed south along Lovekin Boulevard to connect to two SoCalGas pipelines that run along 14th Street, about one mile north of the site.

The site has level topography. Adjacent land uses include a wastewater treatment plant north of the proposed site, an auto-recycling yard to the west, fuel or water storage tanks south of the site, and a hay storage facility on the eastern side of the site. In addition, there are several residences interspersed on 16th Avenue and approximately nine trailer homes on Lovekin Boulevard. The nearest residence is on the west side of Lovekin Boulevard, approximately 250 feet from the edge of the site property.

Impact Discussion

Following is a discussion of potential environmental impacts at the South of Blythe Site:

- **Air Quality:** This site is located in the MDAQMD and in close proximity to the proposed project, so potential impacts would be similar to those of the proposed project. Mitigation measures would reduce proposed project impacts to less-than-significant levels, thus similar conclusions and measures would apply to this alternative site to reduce air quality impacts to less-than-significant levels.
- **Cultural Resources:** To determine potential impacts of a project at this site and along the routes of linear facilities, a background search at the regional CHRIS and a survey of both archaeological and historic resources would be necessary. Because the site is in agricultural use and is already disturbed, it is unlikely that there would be significant impacts to cultural resources with implementation of standard mitigation measures. Siting of the towers and construction of overhead transmission lines up the east face of Palo Verde Mesa to Blythe Substation have the potential to encounter known or unknown cultural resources in the area, and a cultural resources assessment would be necessary to determine the impact significance. In addition, the one-mile long natural gas connection would result in potential disturbance of cultural resources.

- **Land Use:** Half of this site would be located on soils characterized as prime farmland soils (California Department of Conservation, 2005). The City of Blythe is planning on incorporating this area for development and zoning it for commercial and/or industrial uses, so while farmland would be lost with this alternative, it would also likely be lost even without the use of this site for a power plant. This site is farther from the airport and would be less likely to interfere with airport operations, however, it is also closer to the City of Blythe and several sensitive receptors such as residences (~250 feet), which could cause potentially significant impacts due to construction and operational disturbances. Unless dry cooling is used, the land use impacts resulting from the WCOP would be the same as the proposed project because the project at this alternative site would still be using water from the Colorado River.
- **Traffic and Transportation:** This site is located southeast of the proposed project site and considerably farther from the Blythe Airport; therefore, a power plant at this site would not likely affect airport traffic safety and impacts would be less than significant.
- **Transmission System Engineering:** This site would require the construction of a new 5.5-mile transmission line for interconnection into the regional electrical grid.
- **Water and Soil Resources:** As with the proposed project, the use of groundwater for cooling at this site would result in significant impacts from withdrawal of water from the Colorado River Aquifer. Thus, an alternative cooling technology such as dry or hybrid cooling would likely be required to minimize impacts to groundwater. Because of the distance of this site from the Blythe Airport, dry cooling could be utilized at this site. As with the proposed BEP II, if the WCOP were implemented, additional impacts would be created that require mitigation (e.g., soil erosion); however, the WCOP would not be needed if dry cooling were used. Though there is not a landfill onsite, there could be potential groundwater contamination issues associated with the nearby auto-recycling yard. Similar mitigation measures to those required for the proposed BEP II would be required to protect water quality during construction.
- **Noise:** The nearest residence to the proposed project is approximately 250 feet southwest of the site. Therefore, the closer proximity of the nearby residences and sensitive receptors and the City of Blythe would increase the potential for significant impacts from project construction and operation. Modeling would be required to determine the significance of this impact; extensive mitigation would be required to reduce impacts to less than significant.
- **Biological Resources**: As with the proposed project, the use of evaporation ponds would need to be mitigated through the use of zero-liquid discharge (ZLD) to eliminate potential impacts to birds. Due to the disturbed nature of the site, it is unlikely that there would be significant impacts to other biological resources. However, the construction of the transmission line would affect the desert flora located on the east face of the mesa. Due to low rainfall and elevations, coupled with extreme temperatures, the vegetation in the project area is typically drought-adapted, simple, sparse, and easily susceptible to impact from disturbance. Construction of the gas pipeline could also affect biological resources unless it were kept within existing roadways. However, for all impacts, standard mitigation (e.g.,

site fencing for desert tortoises, surveys for burrowing owl nests, worker education, etc.) would likely reduce potential biological impacts to less than significant.

- **Hazardous Materials**: The risk associated with use and transport of anhydrous ammonia and other hazardous materials at the South of Blythe Site would be greater than at the proposed project site due to the proximity of sensitive receptors and transport through the City of Blythe, which would be likely required due to the location of this site south of the center of the city. Mitigation (e.g., definition of safe travel routes for anhydrous ammonia deliveries) would likely be required for LORS compliance and would reduce potential impacts to less than significant.
- **Geological Resources**: The South of Blythe Site is located on the Palo Verde Valley floor, which has a higher groundwater table than at the proposed project site. This increased soil saturation could pose an increased seismic risk due to potential liquefaction of the soil. Mitigation measures and/or changes in plant design and construction to withstand ground shaking in the event of a major earthquake would be necessary to reduce this impact to less than significant.
- **Visual Resources**: The close proximity to central Blythe and to nearby residences has the potential for significant visual impacts to be created at this site. In addition, the required transmission line would cross primarily agricultural lands and up the east side of the mesa, and would most likely be highly visible from the City of Blythe, causing substantial visual intrusion. Mitigation, such as landscaping, power plant color, or transmission tower design would likely reduce these impacts to less than significant levels. If dry cooling is used to mitigate water supply impacts, the more massive structures may create a significant visual impact to the nearby residences.

BLYTHE AIRPORT SITE

The Blythe Airport Site (applicant's alternative Site B) is located within the Blythe Airport property boundary on the Palo Verde Mesa and is zoned Industrial-Commercial. The airport is currently under a long-term 75-year lease to the City of Blythe from Riverside County. The site is located to the northeast of the northwest-southeast runway. It is bordered to the northeast by the airport perimeter road, to the southeast and northwest by vacant land, and to the southwest by one of the airport taxiways. The nearest residences are located more than one mile south-southwest of the site in an unincorporated residential community within Mesa Verde.

The proposed BEP II site is within the jurisdiction of the ALUC, located immediately adjacent to a runway safety zone (protection areas defined beyond the end of each runway). The Blythe Airport site, while closer to the runways themselves and at the same elevation, is about a half mile from the safety zones at the ends of runways 17 and 25.

This site is generally flat and currently vacant with up to 257 acres available for development. It is at the same elevation as the airport and its associated facilities.

The project at this location would require the construction of either a 2.5-mile transmission line southeast to Western's Buck Boulevard Substation or a 3-mile line southeast to Western's Blythe Substation. This site would require the 2.5 mile extension of the natural gas pipeline from the original BEP I site or the construction of a

new gas pipeline to one of the two SoCalGas pipelines, located approximately 2.75 miles south of the Blythe Airport Site. These new underground pipeline routes would likely run along the eastern airport boundaries and traverse over mostly unimproved land. Similar to the proposed project, it is assumed that cooling water would likely be supplied via groundwater wells.

Impact Discussion

Following is a discussion of potential environmental impacts at the Blythe Airport Site:

- **Air Quality**: This site is located in the MDAQMD and in close proximity to the proposed project, so potential impacts would be similar to those of the proposed project. Mitigation measures would reduce proposed project impacts to less-than-significant levels, thus similar conclusions and measures would apply to this alternative site to reduce air quality impacts to less than significant levels.
- **Cultural Resources**: To determine potential impacts of a project at this site and the required linear facilities, 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 significant impacts; however, the need to construct additional linear facilities (natural gas pipeline and transmission lines) would create greater ground disturbance than at the proposed BEP II site. Standard mitigation would likely reduce any potential impacts to less than significant.
- **Land Use**: The Blythe Airport Site is located within the Blythe Airport property boundary and is zoned Industrial-Commercial. The proposed site would be consistent with the land use designation and would not be located in line with any of the runways, or within the safety zones. However, the location of this site within the airport itself would likely create the same LORS inconsistencies as the proposed project due to the objections of the ALUC and Caltrans to having a power plant located near an airport.
- **Traffic and Transportation**: This alternative site is within the Blythe Airport property boundary and in closer proximity to runways than the proposed BEP II site. In contrast to BEP II, this site is not within any of the runway safety zones, However, the visible plume from the cooling towers (if dry cooling is not used) could briefly cross the nearby runway, affecting visibility, and thermal plumes from either dry or wet cooling could affect aircraft operations during turns in runway approach. The obstruction created by the facility itself could create a safety hazard. Further, the conflict with LORS due to the site location within airport lands would still occur (based on anticipated opposition from the ALUC and Caltrans).
- **Transmission System Engineering**: This site would require additional linear facilities to tie into the region's electrical system at Buck Boulevard Substation, or directly to Western's Blythe Substation.
- **Water and Soil Resources**: As with the proposed project, the use of groundwater at this site would result in significant impacts related to water supply due to demand on the Colorado River Aquifer. Similar mitigation measures to BEP II would be required to reduce the potential impacts resulting from implementation of the WCOP to less than significant. Dry cooling could be used at this site to mitigate the water

supply impacts, but the thermal plume could adversely affect aircraft safety, similar to the situation at the proposed site. Therefore, like the proposed project, water supply impacts would remain significant.

- **Biological Resources**: As with the proposed project, the use of evaporation ponds could have a significant impact to birds nesting and feeding at the site, and aviation safety from flocks of birds flying into aircraft. Therefore, the use of evaporation ponds would need to be eliminated using ZLD or designed to keep birds off the ponds at all times. The need to construct additional linear facilities (natural gas pipeline and transmission lines) would create greater ground disturbance than at the proposed BEP II site, which could have a greater effect on biological resources than the proposed project. In addition, the required transmission line would cross the desert flora located on the mesa, which could result in biological impacts. Due to low rainfall and elevations, coupled with extreme temperatures, the vegetation in the project area is typically drought-adapted, simple, sparse, and easily susceptible to impact from disturbance. Though also low because of past disturbance, the probability of biological impacts is greater than at the BEP II location because the alternative site is located on a large parcel of currently vacant land. Implementation of mitigation measures (e.g., site fencing for desert tortoises, surveys for burrowing owl nests, worker education, etc.) would likely reduce any potential biological impacts to less than significant.
- **Visual Resources**: Viewers anticipate open, panoramic views in a predominantly agricultural setting, therefore the addition of prominent geometric forms with significant mass that would interrupt the open expanse and block views of the surrounding hills could be perceived as an adverse visual change. The Blythe Airport Site is located further from main roadways and would be less visible to travelers. Mitigation, such as landscaping or power plant color, is likely to reduce impacts to less than significant. If dry cooling is used, the more massive structures may create a potentially significant visual impact; however, the facility would be located at some distance from sensitive receptors, so it could likely be designed to reduce visual impacts. Although site-specific analysis would be required to evaluate impacts from residences and viewing sites, impacts would likely be reduced to less than significant levels.

INTERSTATE 10 SITE

The Interstate 10 site was identified by staff. The site is in unincorporated Riverside County and is undeveloped agricultural land bordered by West 14th Avenue to the north, the West Side Drain to the west, Seeley Avenue to the south, and Arrowhead Boulevard to the east. A canal crosses the site between the West Drain and C-05 Canal. A gas compressor station for the SoCalGas pipeline that runs along the south side of I-10 is located across the street to the north of West 14th Avenue. The proposed power plant could most likely connect to this station to receive natural gas. Similar to the proposed project, the I-10 Site would most likely receive its water from groundwater wells. The nearest locations to tie into the regional electrical grid would be at Western's Blythe Substation, approximately 2.5 miles to the west-northwest. Alternatively, it might be possible to connect with the future Midpoint Substation (proposed to be constructed as part of the DPV2 Project), south of I-10 approximately five miles west-southwest of this alternative site.

The County General Plan designation for this land is Industrial, and the County Zoning designation is Medium Manufacturing. The topography of the land is flat bordered by open fields to the south. There are four residences located approximately 0.45 miles west of the site.

Impact Discussion

Following is a discussion of potential environmental impacts at the Interstate 10 Site:

- **Air Quality**: This site is located in the MDAQMD and in close proximity to the proposed project, so potential impacts would be similar to those of the proposed project. Mitigation measures would reduce proposed project impacts to less-than-significant levels, and similar conclusions and measures would apply to this alternative site to reduce air quality impacts to less-than-significant levels.
- **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. However, the I-10 Site would be located on disturbed agricultural land near a gas compressor station and I-10, and without natural waterways or structures, so the potential for significant cultural resources impacts is low.
- **Land Use**: This entire site has irrigated prime farmland according to the State Department of Conservation (2005). However, the County General Plan designation for this land is Industrial, and the County Zoning designation is Medium Manufacturing, therefore, a power plant at this site would be consistent with the land use designation. However, the residences to the west of this site and the nearby gas compressor station may cause land use and space constraint issues.
- **Transmission System Engineering**: This site would require a new transmission line to tie into the region's electrical system at Western's Blythe Substation or to the new Midpoint Substation.
- **Traffic and Transportation**: This site is located southeast of the proposed project site and considerably farther from the Blythe Airport; therefore, a power plant at this site would not likely affect airport traffic safety and impacts would be less than significant.
- **Water and Soil Resources:** As with the proposed project, the use of groundwater at this site would result in significant impacts related to water supply due to demand on the Colorado River Aquifer. Similar mitigation measures to BEP II would be required to reduce the potential impacts resulting from implementation of the WCOP to less than significant. Thus, an alternative cooling technology such as dry or hybrid cooling would likely be required to minimize impacts to groundwater. Because of the distance from the Blythe Airport, the thermal plumes from either wet or dry cooling towers would not create aircraft safety hazards at this site.Biological Resources. As with the proposed project, the use of evaporation ponds could have a significant impact on birds nesting and feeding at the site. Mitigation measures, such as ZLD, would need to be implemented to eliminate the evaporation ponds or ensure that migratory birds are not allowed on the site for any prolonged time.
- **Noise**: Ambient noise levels in the vicinity are relatively high due to traffic on I-10. However, there are homes located 0.45 miles west of this alternative site that could

be impacted by a power plant at this site. The nearest residence to the proposed project is approximately 0.75 miles southwest of the site. Even with the closer proximity of residences, 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.

- **Hazardous Materials**: Based on the easy truck-route access to I-10, the risk associated with anhydrous ammonia and other hazardous materials would likely be less than those at the proposed site and the other alternatives. However, this site does have residences and a gas compressor station nearby. Mitigation would likely be required for LORS compliance and to ensure that potential impacts would be less than significant.
- **Visual Resources**: This alternative site would be located approximately the same distance south of the I-10 freeway as the proposed site is north of the freeway. Viewer concern at this site is considered to be moderate, as travelers on I-10 anticipate open, panoramic views of the predominantly agricultural setting. The nearby residents would also be subject to adverse visual change. However, the existing setting is somewhat industrial, with the nearby SoCalGas compressor station and the I-10 itself. As a result, while the visual impacts of a power plant at this site could be significant, available mitigation (e.g., appropriate paint color and trees for screening) would likely reduce impacts to less than significant. If dry cooling were used to mitigate water supply impacts, visual impacts would be potentially significant. Site-specific analysis of the location and facility design options would be required to evaluate impacts from nearby residences and viewing sites; facility design options might reduce impacts to less than significant levels.

DEVERS SITE

The Devers Site is located approximately 118 miles west of the proposed site in Riverside County within an area annexed by the City of Palm Springs, approximately eight miles northwest of its center (see ALTERNATIVES Figure 2). This site was selected because it was previously proposed as a power plant site: the 456 MW Ocotillo Energy Project, Phase I (01-AFC-8). The description provided here and the impact analysis is based on that AFC and information provided in the Energy Commission staff's Preliminary Staff Assessment (September 2001).

The City of Palm Springs has zoned the site Energy/Industrial. The site is currently used for wind generation and is located southwest of Desert Hot Springs, approximately one mile east of State Route 62 (Twentynine Palms Highway), one mile north of I-10, and one to one and a half miles west of Indian Avenue. Dillon Road runs along the south side of the property and the SCE Devers Substation is located to the north. Approximately 0.3 mile from the west border of the Devers Site is Diablo Road and a residential community. There is another residential community 2.5 miles southwest of the site. The surrounding area is dominated by wind turbine generators and transmission lines. The site itself has nearly level topography. Nine existing wind turbines would have to be removed if this site is used. Independent of use of this alternative site, approximately 90 other wind turbines are undergoing testing for use in Alaska and will be removed by that developer.

Less than one mile of transmission line would have to be built across vacant land to the SCE's Devers Substation, approximately 0.6 miles north of the site.
Natural gas would be supplied to the site by a SoCalGas pipeline. SoCalGas has two 30-inch pipelines located approximately two miles from the site along the south side of I-10. This site is located within the Mission Springs Water District (MSWD), a possible provider of reclaimed water via an existing pipeline. Some of the process water could be supplied via on-site groundwater wells drilled into the Garnet Hill Sub-basin and potable water could be supplied from the MSWD by an existing water line at the southern boundary of the site along Dillon Road. However, at this time MSWD does not have an adequate supply of reclaimed water so additional water would have to be imported from an external supply until the facility could expand to meet the increased demand (MSWD 2003).

Impact Discussion

Following is a discussion of potential environmental impacts at the Devers Site:

- **Air Quality**: Unlike the proposed project, this site is located in Salton Sea Air Basin of the South Coast Air Quality Management District (SCAQMD), so the cost of offsets would be higher. More stringent permitting requirements would be implemented and many of the Emissions Reduction Credits (ERCs) that were carried over from BEP I for BEP II would be invalid in the SCAQMD. Despite the different jurisdiction and setting, mitigation measures would likely be available to reduce potential impacts to less than significant (e.g., emissions limits, compliance tests, etc.).
- **Cultural Resources**: Surveys conducted for the Ocotillo Energy Project did not identify archaeological sites within the project site, although there were potential sites within 1,000 feet of the project components (including linears). Based on this information, standard mitigation measures would likely reduce potential impacts to cultural resources to less than significant levels.
- **Land Use**: The area surrounding the Devers Site includes the Devers Substation, numerous transmission lines, wind turbines, and vacant land. Low density residences are located to the east and west of this site. The site is zoned Energy/Industrial (E-1) but a large power plant would not be in compliance with the City of Palm Springs' ordinance, which does not allow for natural gas fueled electrical generation facility usage. Therefore, unless the City Council passed a zoning amendment that would include this use in the zoning code, a plant at this site would be inconsistent with zoning, and, therefore, infeasible.
- **Transmission System Engineering**: This site would connect to the electric grid at the SCE Devers Substation, at the western end of the proposed DSWTP transmission line and/or the proposed DPV2 500 kV transmission line. Less than one mile of transmission line would have to be built across vacant land to the SCE's Devers Substation, approximately 0.6 miles north of the site. Approximately 118 miles of transmission would be eliminated, thereby reducing electric system losses proportional to transmission distance, as well as concerns about transmission capacity availability in the "South of Parker" Western system associated with the addition of the proposed project to the grid. However, as is the case for the proposed project site and all alternatives, an interconnection study would be

necessary before staff could determine whether system reliability impacts would be less than significant and identify downstream facilities and their environmental impacts.

- **Traffic and Transportation**: The closest airport is the Palm Springs International Airport, located approximately 6.5 miles to the southeast. Therefore, a power plant at this site would not affect airport traffic safety and potential impacts to traffic and transportation would be less than significant.
- **Water and Soil Resources:** Because MSWD does not have an adequate supply of reclaimed water to meet the demand of a power plant at this time, there may not be sufficient water available for use in the proposed wet (evaporative) cooling system. However, if no other adequate supplies of water were identified, dry cooling technology could be used at this site. Visual impacts of the dry cooling towers may be significant.
- **Biological Resources**: The quality of water at the Devers Site is not known. If the selenium content and salinity are lower than the BEP II site, the effect on migratory birds using of evaporation ponds may be less than significant. If water quality remains a concern at this site, mitigation measures, such as ZLD, would need to be implemented to eliminate the evaporation ponds or other mitigation measures would be needed to ensure that birds are not allowed on the site for any prolonged period of time. Evaporation ponds at this site would also be of concern due to the presence of wind turbines in the area. If the ponds attracted migratory birds to the area, they would be at risk of injury or death from collision with the blades of the wind turbines in the immediate area.

  Though the site is low to moderate quality Mojave desert scrub interspersed with ruderal and developed areas, there would be potential offsite impacts on the desert tortoise, a federally and state listed species, and its critical habitat. Desert tortoise could be affected both directly, due to site disturbance, and indirectly, due to nitrogen deposition from plant emissions. Joshua Tree National Park's western border is approximately seven miles east of the Devers Site. The park is heavily air-pollutant impacted and is also desert tortoise habitat. Nitrogen deposition from power plant emissions would likely occur in the park (and elsewhere), which would favor non-native, invasive vegetation, which does not provide the same nutritional value as native vegetation. Therefore, detailed biological studies and mitigation measures, such as emissions control, habitat restoration after construction, compensation packages, and purchase of mitigation lands, would be necessary to reduce these impacts to less than significant.
- **Geological Resources**: The Banning segment of the San Andreas Fault is located approximately 0.1 mile from the center of the site, and though the project site does not cross the fault, it is located within Seismic Zone 4 of the Uniform Building Code, the highest earthquake hazard zone recognized by the code. Therefore, a plant and the linear facilities would be located within the zone of extreme near-field effects where damage could be excessive in the event of an earthquake. Geotechnical and geological studies and/or changes in plant design (in accordance with the California Building Code) and construction would be necessary required to ensure that the facility could withstand a major earthquake. With appropriate design, impacts would be less than significant.

- **Visual Resources**: The Devers Site is a 54-acre site with generally level but slightly rolling desert terrain and adjacent industrial land uses, including several major transmission lines and the 500 kV SCE Devers Substation to the northwest. In addition, the area in and around the San Gorgonio Pass and adjacent to the alternative site has more than 4,000 wind turbine generators (OEP 2001). These wind turbines range in height from 80 to 150 feet with rotors that add an additional 16 to 105 feet to the tower height. There are residences 0.3 miles west of the alternative site. While the area has major electricity infrastructure, the lack of vegetation and generally level topography allows extended views. Therefore, visual impacts at this location would be potentially significant, but would likely be mitigable to less than significant levels with mitigation (e.g., structure painting to blend with surroundings and vegetative screening). However, site analysis would be needed to determine if design options could mitigate the visual impacts of the air cooled condensers required for dry cooling.

NO PROJECT (NO ACTION) ALTERNATIVE

The "no project" alternative under CEQA assumes that the project is not constructed. In the CEQA analysis, the "no project" alternative is compared to the proposed project and determined to be 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)). DOE's NEPA regulations require that an EA include a discussion of the no action alternative (10 CFR 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.

In the absence of the BEP II project, two types of events are likely to occur. First, other power plants could be constructed in California to serve the demand that could be met with the BEP II project. Second, new transmission lines could be constructed to import electricity generated out-of-state into California markets. For example, SCE's proposed DPV2 project would import about 1,200 MW of existing generation capacity from Arizona into California. While this additional power would replace the 520 MW that would have been generated at BEP II, it would also serve to increase California's reliance on out-of-state generation.

Due to the uncertain status of the DSWTP, the BEP II project has no viable transmission connection to the grid, and as a result it may not be able to achieve the potential benefits of contributing to California's generating resources, increasing competition, and helping to form a more reliable electric system. If this facility were not constructed, the proposed site would remain as open space, and additional power to

meet both the applicant's objectives and the State's needs would not be available from this project.

With a viable transmission connection to California markets, the proposed facility could also serve to replace older, inefficient facilities. However, if the "no project" alternative were selected, the construction and operational impacts of the BEP II would not occur. Additional demand on groundwater supplies, conflict with airport operations, and impacts on migratory birds using the ponds would be avoided. Most of these impacts could be avoided with use of an alternative site, though design changes such as dry cooling and ZLD would likely be required at any site in the Blythe area.

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:

- Conservation and demand side management; and
- Renewable resources.

These alternatives, and the reasons they were not considered in detail in this analysis, are described below.

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 2002c) 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 2002c).

After the CAISO 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 2002-2003 demand has been increasing as the memories of rolling blackouts fade.

The CPUC 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 520 MW BEP II project. In order to generate 520 MW, which is proposed for the BEP II, twenty-six 20 MW biomass facilities would be required. However, these power plants would have potentially significant environmental impacts of their own (CEC 2001a).

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 to eight 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 520 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 520 MW would require 2,600 acres. For a PV plant, generation of 520 MW would require 2,080 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 demand and generate 520 MW of electricity.

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 520 MW of electricity. Depending on the size of the wind turbines, wind generation "farms" generally require between 5 and 17 acres to generate one megawatt (resulting in the need for between 2,600 and 8,840 acres to generate 520 MW) (CEC 2001b). 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 2001c). 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 demand and generate 520 MW of electricity.

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.

RESULTS OF WESTERN'S REVIEW OF ALTERNATIVE SITES

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.

Potential site-specific impacts of the BEP II 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 throughout this document would be avoided by the no action alternative.

CONCLUSIONS

ALTERNATIVES Table 1 presents a summary of the impacts of the four site alternatives and how their impacts compare with those of the proposed project. As discussed above, the alternative site analyses and the following table address the following disciplines: land use, traffic and transportation, transmission system engineering, water and soil resources, biological resources, cultural resources, air quality, visual resources, geological concerns, noise, and hazardous materials. The remaining disciplines (public health, socioeconomics, transmission line safety and nuisance, waste management, workers' safety and fire protection, and facility design) were all considered to have impacts that would be similar to those of the proposed project, so they are not presented in the table.

Overall, the four site alternatives considered offer some advantages and disadvantages in comparison to the proposed project. The need for new transmission studies would apply to all alternative sites. Significant impacts would remain for all alternative sites in the issue areas of biological resources (unless zero-liquid discharge [ZLD] is used) and water resources (unless dry cooling is used). The alternative site adjacent to the airport would have similar adverse land use and traffic and transportation impacts as the project. All other potential impacts at the alternative sites would be reduced to less than significant levels with the implementation of mitigation measures.
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Of the alternatives considered, the I-10 site provides a feasible alternative to the BEP II project. Because this site is not near the airport, dry cooling could be used and would mitigate the project's impacts to water resources. A zero liquid discharge system would eliminate impacts to migratory birds. Although there are potential noise and visual resource impacts associated with this site, these impacts are likely mitigated to a less than significant level. The I-10 site is on prime farmland, so mitigation would also be required to compensate for the loss of farmland.

ALTERNATIVES Table 1
Comparison of Impacts of Alternatives to the Proposed Blythe Energy Project II
(Shaded cells illustrate potential significant impacts)

Issue Area	South of Blythe Site Alt.	Blythe Airport Site Alt.	Interstate 10 Alt.	Devers Site Alt.
Environmental Assessment				
Air Quality	Similar impacts to proposed project; impacts less than significant with mitigation.	Similar impacts due to proximity to proposed project; impacts less than significant with mitigation.	Similar impacts to proposed project; impacts less than significant with mitigation.	Different air district (SCAQMD) but impacts would be similar and less than significant with mitigation.
Biological Resources	Similar impacts from evaporation ponds; impacts less than significant with use of ZLD.	Similar impacts from evaporation ponds. Slightly greater impacts due to greater ground disturbance for linears; impacts less than significant with mitigation and use of ZLD.	Similar impacts from evaporation ponds. Slightly less impacts because of disturbed nature of site; impacts less than significant with mitigation and use of ZLD.	Similar impacts from evaporation ponds. Slightly greater impacts associated with disturbance of desert tortoise from air pollutants; impacts less than significant with mitigation and use of ZLD.
Cultural Resources	Similar impacts; impacts less than significant with mitigation.	Slightly greater impacts due to greater ground disturbance for linears; impacts less than significant with mitigation.	Slightly less impacts because of disturbed nature of site; impacts less than significant with mitigation.	Similar impacts; impacts less than significant with mitigation.
Hazardous Materials	Greater impacts due to closer proximity to sensitive receptors (closest residence ~250 feet) and transport through Blythe; impacts less than significant with mitigation.	Similar impacts to proposed project; impacts less than significant with mitigation.	Less impacts due to proximity to Interstate 10 and reduced travel distance; impacts less than significant with mitigation.	Similar impacts to proposed project; impacts less than significant with mitigation.
Land Use	Slightly greater impacts because closer to sensitive receptors (~250 feet) but farther from the airport. Half of site on prime farmland. Impacts likely less than significant with mitigation.	**Impacts from LORS conflict would remain significant.**	Slightly greater impacts because closer to sensitive receptors (4 residences 0.45 miles west of site), but farther from the airport and designated Industrial. Entire site is prime farmland. Impacts less than significant with mitigation.	**Located in industrial area, but City of Palm Springs zoning modification necessary. Residences 0.3 miles west of site. Required zoning modification is considered significant impact.**

Issue Area	South of Blythe Site Alt.	Blythe Airport Site Alt.	Interstate 10 Alt.	Devers Site Alt.
Noise and Vibration	**Greater impacts due to closer proximity to sensitive receptors (closest residence ~250 feet). Modeling would be needed to determine effects of operational noise on residences.**	Similar impacts; impacts less than significant with mitigation.	Slightly greater impacts due to closer proximity to sensitive receptors (4 residences 0.45 miles west of site), but ambient noise high from I-10. Impacts less than significant with mitigation.	Slightly less impacts since ambient levels are high from wind farms. Impacts less than significant with mitigation.
Soil and Water	Similar impacts due to proposed groundwater usage; impacts less than significant with use of dry cooling.	**Similar impacts due to proposed groundwater usage; dry cooling could *not* be used due to airport proximity. Impacts remain significant and unmitigable.**	Similar impacts due to proposed groundwater usage; impacts less than significant with use of dry cooling.	Similar impacts due to water availability concerns; impacts less than significant with use of dry cooling.
Traffic and Transportation	Less impacts from air traffic safety due to greater distance from airport. Impacts less than significant with mitigation.	**Similar impacts to air traffic safety due to thermal/ visible plumes and proximity to airport. Impacts remain significant and unmitigable. Similar conflict with LORS due to the site location within airport lands.**	Less impacts from air traffic safety due to greater distance from airport and proximity to I-10, but closer to sensitive receptors during construction activity. Impacts less than significant with mitigation.	Less impacts; no airport conflicts. Impacts less than significant with mitigation.
Visual Resources	Similar impact to proposed site. Mitigation would reduce visual impacts of plant to less than significant. If dry cooling were used, visual impacts could be significant, but design options might mitigate to less than significant.	Greater impacts because located higher on mesa, but mitigation could reduce visual impacts to less than significant. Site analysis needed to determine if design options could mitigate impacts if dry cooling were used.	Similar impact to proposed site. Mitigation would reduce visual impacts of plant to less than significant. Site analysis needed to determine if design options could mitigate impacts if dry cooling were used.	Similar impacts. Site located in area with adjacent industrial land uses (large substation, transmission lines). Impacts less than significant with mitigation. Site analysis needed to determine if design options could mitigate impacts if dry cooling were used.
Engineering Assessment				
Geology, Mineral Resources, and Paleontology	Greater impacts due to liquefaction risk from higher groundwater table. Impacts less than significant with mitigation.	Similar impacts. Impacts less than significant with mitigation.	Similar impacts. Impacts less than significant with mitigation.	Greater impacts due to proximity to Banning Fault (0.1 miles). Impacts less than significant with mitigation.

Transmission System Engineering	System impact study needed.	System impact study needed.	System impact study needed.	System impact study needed. Fewer impacts due to elimination of 118 miles of transmission lines, reducing electric system losses.

As determined by Energy Commission staff in the FSA, the BEP II project as proposed would cause potential impacts in land use, water and soil resources, biological resources, traffic and transportation, and transmission system engineering. All of the alternative sites would have similar concerns regarding biological resources, so that impact would be similar with use of an alternative site and use of mitigation measures such as ZLD would be required to reduce impacts to less than significant. Construction of the power plant at three alternative sites (the South of Blythe Site, the Interstate 10 Site, and the Devers Site) would eliminate the land use and air traffic safety conflicts with the Blythe Airport. At three sites (South of Blythe, Devers, and Interstate 10), dry cooling would be feasible so the impact on groundwater supplies could be avoided. Finally, the three Blythe area sites (South of Blythe, Blythe Airport, and Interstate 10) would all have the same uncertainties as the proposed project with respect to transmission availability.

In conclusion, the Interstate 10 Site has the best potential for reducing or eliminating the significant impacts of the proposed project, and no significant impacts have been identified. The South of Blythe Site is less advantageous due to the proximity of residences to the site, but no significant impacts have been identified at that site. The Blythe Airport Site would have the same inconsistencies with Laws, Ordinances, Regulations and Standards (LORS) resulting from proximity to the airport that occur with the proposed BEP II site, and the Devers Site would require rezoning, which is considered a significant impact.

REFERENCES

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GENERAL CONDITIONS
INCLUDING
COMPLIANCE MONITORING AND CLOSURE PLAN

Testimony of Steve Munro and Alvin Greenberg, Ph.D.

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; and
- specify conditions of certification that follow each technical area that 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:

a. the installation of environmental monitoring equipment;

b. a soil or geological investigation;

c. a topographical survey;

d. any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility; or

e. any work to provide access to the site for any of the purposes specified in a., b., c., or d.

START OF COMMERCIAL OPERATION

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.**

COM-1, Unrestricted Access

The CPM, responsible Energy Commission staff, and delegate agencies or consultants, shall be guaranteed and granted unrestricted access to the power plant site, related facilities, project-related staff, and the files and 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.

COM-2, Compliance Record

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.

COM-3, Compliance Verification Submittals

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.

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.

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:

Steve Munro
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.

COM-4, Pre-Construction Matrix and Tasks Prior to Start of Construction

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, and shall be submitted prior to the first pre-construction meeting, if one is held. It will be in the same format as the compliance matrix referenced below.

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 construction.

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.
It is 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.

EMPLOYEE ORIENTATION

Environmental awareness orientation and training will be developed for presentation to new employees during project construction as approved by Energy Commission staff and described in the conditions for Biological, Cultural, and Paleontological resources. At the time this training is presented, the project owner's representative shall present information about the role of the Energy Commission's delegate Chief Building Official (CBO) for the project. The role and responsibilities of the CBO to enforce relevant portions of the Energy Commission Decision, the CBSC, and other relevant building and health and safety requirements shall be briefly presented. As part of that presentation, new employees shall be advised of the CBO's authority to halt project construction activities, either partially or totally, or take other corrective measures, as appropriate, if

the CBO deems that such action is required to ensure compliance with the Energy Commission Decision, the CBSC, and other relevant building and health and safety requirements. At least 30 days prior to construction, the project owner shall submit the proposed script containing this information for CPM review and approval.

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.

COM-5, Compliance Matrix

A compliance matrix shall be submitted by the project owner to the CPM along with each monthly and annual compliance report. The compliance matrix is intended to provide the CPM with the current status of all compliance conditions in a spreadsheet format. The compliance matrix must identify:

1. the technical area;
2. the condition number;
3. a brief description of the verification action or submittal required by the condition;
4. the date the submittal is required (e.g., 60 days prior to construction, after final inspection, etc.);
5. the expected or actual submittal date;
6. the date a submittal or action was approved by the Chief Building Official (CBO), CPM, or delegate agency, if applicable;
7. the compliance status of each condition (e.g., “not started,” “in progress” or “completed” (include the date); and
8. the project’s preconstruction and construction milestones, including dates and status (if milestones are required).

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.

COM-6, Monthly Compliance Report

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 (or amount specified by Compliance Project Manager) 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;
4. a list of conditions 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;
9. a listing of the month's additions to the on-site compliance file;
10. any requests, with justification, to dispose of items that are required to be maintained in the project owner's compliance file; and
11. a listing of complaints, notices of violation, official warnings, and citations received during the month, a description of the resolutions of any resolved complaints, and the status of any unresolved complaints.

COM-7, Annual Compliance Report

After construction is complete, 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. 11an 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.

COM-8, Construction and Operation Security Plan

At least 14 days prior to commencing construction, a site-specific Security Plan for the construction phase shall be submitted to the CPM for approval. At least 30 days prior to the initial receipt of hazardous materials on-site, a site-specific Security Plan for the operational phase shall be submitted to the CPM for review and approval.

Construction Security Plan

The Construction Security Plan shall include the following:

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.

Operation Security Plan

1. The Operations Security Plan shall include the following:
2. permanent site fencing and security gate;
3. evacuation procedures;
4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency;
5. fire alarm monitoring system;

6. site personnel background checks, including employee and routine on-site contractors [Site personnel background checks are limited to ascertaining that the employee's claims of identity and employment history are accurate. All site personnel background checks shall be consistent with state and federal law regarding security and privacy.];
7. site access for vendors; and
8. requirements for Hazardous Materials vendors to prepare and implement security plans as per 49 CFR 172.800 and to ensure that all hazardous materials drivers are in compliance with personnel background security checks as per 49 CFR Part 1572, Subparts A and B.

In addition, the Security Plan shall include one or more of the following in order to ensure adequate perimeter security:

1. security guards;
2. security alarm for critical structures;
3. perimeter breach detectors and on-site motion detectors; and
4. video or still camera monitoring system.

In addition, in order to determine the level of security appropriate for this power plant, the project owner shall prepare a Vulnerability Assessment that is consist with guidelines including but not limited to the Chemical Accident Prevention Alert regarding Site Security (EPA 2000), the Department of Justice Chemical Facility Vulnerability Assessment Methodology (US DOJ 2002), the North American Electric Reliability Council Security Guidelines for the Electricity Sector (NAERC 2002), the U.S. Department of Energy Vulnerability Assessment Methodology for Electric Power Infrastructure (DOE 2002), and the California Energy Commission. The level of security to be implemented is a function of the likelihood of an adversary attack, the likelihood of adversary success in causing a catastrophic event, and the severity of consequences of that event. This Vulnerability Assessment will be based, in part, on the use and storage of certain quantities of acutely hazardous materials as described by the California Accidental Release Prevention Program (Cal-ARP, Health and Safety Code section 25531). Thus, the results of the off-site consequence analysis prepared as part of the Risk Management Plan (RMP) will be used to determine the severity of consequences of a catastrophic event and hence the level of security measures to be provided.

The Project Owner shall fully implement the security plans and obtain CPM approval of any substantive modifications to the Security Plan. The CPM may authorize modifications to these measures, or may recommend additional measures depending on circumstances unique to the facility, and in response to industry-related security concerns.

COM-9, Confidential Information

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.

COM-10, Department of Fish and Game Filing Fee

Pursuant to the provisions of Fish and Game Code Section 711.4, the project owner shall pay a filing fee in the amount of $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.

COM-11, Reporting of Complaints, Notices, and Citations

Prior to the start of construction, the project owner must send a letter to property owners living within one mile of the project notifying them of a telephone number to contact project representatives with questions, complaints or concerns. If the telephone is not staffed 24 hours per day, it shall include automatic answering with date and time stamp recording. All recorded inquiries shall be responded to within 24 hours. The telephone number shall be posted at the project site and made easily visible to passersby during construction and operation. The telephone number shall be provided to the CPM who will post it on the Energy Commission's web page at:

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

COM-12, Planned Closure

In order to ensure that a planned facility closure does not create adverse impacts, a closure process that provides for careful consideration of available options and applicable laws, ordinances, regulations, standards, and local/regional plans in existence at the time of closure, will be undertaken. To ensure adequate review of a planned project closure, the project owner shall submit a proposed facility closure plan to the Energy Commission for review and approval at least twelve months prior to commencement of closure activities (or other period of time agreed to by the CPM). The project owner shall file 120 copies (or other number of copies agreed upon by the CPM) of a proposed facility closure plan with the Energy Commission.

The plan shall:

1. identify and discuss any impacts and mitigation to address significant adverse impacts associated with proposed closure activities and to address facilities, equipment, or other project related remnants that will remain at the site;
2. identify a schedule of activities for closure of the power plant site, transmission line corridor, and all other appurtenant facilities constructed as part of the project;
3. identify any facilities or equipment intended to remain on site after closure, the reason, and any future use; and
4. address conformance of the plan with all applicable laws, ordinances, regulations, standards, local/regional plans in existence at the time of facility closure, and applicable conditions of certification.

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.

COM-13, Unplanned Temporary Closure/On-Site Contingency Plan

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 the analysis 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).

COM-14, Unplanned Permanent Closure/On-Site Contingency Plan

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 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 that the Energy Commission 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, OWNERSHIP CHANGES, INSIGNIFICANT PROJECT CHANGES AND VERIFICATION CHANGES

The project owner must petition the Energy Commission pursuant to Title 20, California Code of Regulations, section 1769, in order to modify project design, operation or performance requirements, and to transfer ownership or operational control of the facility.

A petition is required for **amendments** and for **insignificant project changes** as specified below. 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 CPM, who will file it with the Energy Commission's Docket in accordance with Title 20, California Code of Regulations, section 1209.

The criteria that determine which type of approval process applies are explained below.

AMENDMENT

The project owner shall petition the energy commission, pursuant to Title 20, California Code of Regulations, Section 1769, when proposing modifications to project design, operation, or performance requirements. If a proposed modification results in deletion or change of a condition of certification, or makes changes that would cause the project not to comply with any applicable laws, ordinances, regulations or standards, the petition will be processed as a formal amendment to the final decision, and must be approved by the full commission.

CHANGE OF OWNERSHIP

Change of ownership or operational control also requires that the project owner file a petition, and obtain Commission approval, pursuant to section 1769 (b).

INSIGNIFICANT PROJECT CHANGE

Modifications that do not result in deletions or changes to conditions of certification, and that are compliant with laws, ordinances, regulations and standards may be authorized by the CPM as an insignificant project change pursuant to section 1769(a) (2).

VERIFICATION CHANGE

A VERIFICATION MAY BE MODIFIED BY THE CPM WITHOUT REQUESTING AN AMENDMENT TO THE DECISION IF THE CHANGE DOES NOT CONFLICT WITH THE CONDITIONS OF CERTIFICATION AND PROVIDES AN EFFECTIVE ALTERNATE MEANS OF VERIFICATION.

COM-6, KEY EVENTS LIST

PROJECT: Blythe II Power Project

DOCKET # 02-AFC-1

COMPLIANCE PROJECT MANAGER:

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	Unrestricted 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	Compliance Verification Submittals	The project owner is responsible for the delivery and content of all verification submittals to the CPM, whether the condition was satisfied by work performed by the project owner or his agent.
COM-4	5	Pre-construction Matrix and Tasks Prior to Start of Construction	Construction shall not commence until 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; and ▪ the CPM has issued a letter to the project owner authorizing construction.
COM-5	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-6	6	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.

COM-7	7	Annual Compliance Reports	After construction ends and throughout the life of the project, the project owner shall submit Annual Compliance Reports instead of Monthly Compliance Reports.
COM-8	8	Security Plans	Thirty days prior to commencing construction, the project owner shall submit a Security Plan for the construction phase. Sixty days prior to initial receipt of hazardous material on site, the project owner shall submit an Security Plan & Vulnerability Assessment for the operational phase.
COM-9	9	Confidential Information	Any information the project owner deems confidential shall be submitted to the Dockets Unit with an application for confidentiality.
COM-10	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-11	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-12	10	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-13	11	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-14	12	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.

COMPLAINT REPORT/RESOLUTION FORM

PROJECT NAME: Blythe II Power Project AFC Number: 02-AFC-1C
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 Energy Commission 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.)

BLYTHE ENERGY PROJECT PHASE II
(02-AFC-1)
PREPARATION TEAM

Executive Summary ..... William Pfanner

Introduction ..... William Pfanner

Project Description ..... William Pfanner

Environmental Assessment

Air Quality ..... Brewster Birdsall

Biological Resources ..... Natasha Nelson

Cultural Resources ..... Gary Reinoehl

Hazardous Materials ..... Alvin Greenberg Ph.D. and Rick Tyler

Land Use ..... David Flores

Noise and Vibration ..... Jim Buntin

Public Health ..... Ramesh Sundarewaran

Socioeconomics ..... Amanda Stennick

Soil and Water Resources Summary ..... Natasha Nelson

Traffic and Transportation ..... Dale Edwards, James Adams, and Bill Arnold

Transmission Line Safety and Nuisance ..... Obed Odoemelam, Ph.D.

Visual Resources ..... Mark Hamblin

Waste Management ..... Ramesh Sundarewaran

Worker Safety and Fire Protection ..... Alvin Greenberg Ph.D. and Rick Tyler

Engineering Assessment

Facility Design ..... Shahab Khoshmashrab, Al McCuen and Steve Baker

Geology, Mineral Resources, and Paleontology ..... Patrick A. Pilling, Ph.D., P.E., G.E.

Power Plant Efficiency ..... Kevin Robinson and Steve Baker

Power Plant Reliability ..... Kevin Robinson and Steve Baker

Transmission System Engineering ..... Ajoy Guha, MSEE, P.E. and Al McCuen

Alternatives ..... Susan V. Lee

General Conditions ..... Alvin Greenberg Ph.D. and Steve Munro

Project Assistant ..... Evelyn Johnson

Declarations

&

Resumes

DECLARATION OF
William Pfanner, B.S.

I, William Pfanner, B.S. declare as follows:

1. I am presently employed by The California Energy Commission in the **Systems Assessment and Facilities Siting Division** as a **Project Manager**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Project Description**, for the **Executive Summary, Introduction, and Project Description** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3/30/05 Signed: William Pfanner

At: Sacramento Calif.

William Pfanner
909 Bienville Street
Davis, CA 95616
(530) 792-1587

OBJECTIVE:: Management position developing and facilitating projects that protect and enhance both the natural and man-made environment

HIGHLIGHTS AND QUALIFICATIONS

- Community-oriented planner with 20 years of experience
- Skilled in land planning, environmental law and the development process
- Proven history in city, county and state governments
- Knowledge of Federal, State and local agencies and entitlement process
- Successful manager of large staffs and complex projects
- Reputation for leadership, ethics and outstanding communication skills

EXPERIENCE IN THE PRIVATE SECTOR

California Energy Commission – Project Manager for the Siting of Power Plants. (November 2001-present)

Senior Project Manager - Jones & Stokes. Responsible for managing environmental clearance and regulatory compliance for a 300 mile fiber optic cable installation project in northern California. Facilitated coordination with numerous local, state and federal agencies through final project construction. Also prepared CEQA documents for projects; including the expansion of a wastewater treatment facility and the development of a new recreational marina. (August 1999 to October 2001)

Senior Planner - Quad Knopf. Team leader for siting and permitting Sprint PCS' wireless telecommunication system in the Sacramento region. Also responsible for project management of Environmental Impact Reports, supervision and preparation of technical reports, and the preparation of proposals and firm marketing. (October 1998 to August 1999)

Planning Division Supervisor - Matthews Land Company. Responsible for overseeing planning functions in the Seattle metropolitan area, working to identify viable antenna sites and obtain planning approvals for Nextel's telecommunication system. (July 1997 to October 1998)

Project Manager - Koll Telecommunication Services. Project leader for permitting Sprint PCS' wireless telecommunication system in Sacramento and the Bay Area. Responsible for siting facilities and obtaining planning approvals from city and county jurisdictions, and facilitating the development of collocation sites with other wireless carriers. (January 1996 to June 1997)

Development Consultant - William Pfanner & Associates. Private planning and development consultant. Prepared feasibility studies; assisted in siting design and permitting of a mixed-use residential subdivision, a residential resort facility, and a performing arts and convention center. (January 1987 to December 1995)

Contract Planner - EBA Wastechnologies, Inc. Project Manager. Manager EIR/EIS on a Materials Recovery Facility. Prepared environmental review on Source Reduction/Recycling and Household Hazardous Waste Elements. Prepared Integrated Waste Management Plans. (May 1992 to December 1995)

Environmental Planner - EIP Associates. Project Manager. Prepared EIRs and planning documents on a variety of projects including: a residential/golf course community, the right-of-way preservation/acquisition for light rail, an analysis for a highway corridor redesign, and an analysis for a new university campus. (November 1989 to April 1992)

Project Planner - Michael Clayton & Associates. Assisted in writing EIRs on residential subdivisions and urban in-fill developments and the preparation of the county's Energy. Natural Resources, and Conservation Element and EIR. Also contributed to the preparation of the 120Kv Transmission Line EIS. (January 1987 to October 1989)

EXPERIENCE IN THE PUBLIC SECTOR

City Council, Mayor ProTem and Redevelopment Chairman - Winters, California. (June 1990 to June 1994)

Board of Directors of Woodland Hospital. (June 1992 to December 1994)

Contract Planner - City of Davis. Prepared environmental analysis for a city-operated wastewater treatment/wetlands project proposed in conjunction with the Army Corps of Engineers; completed the city's noise ordinance; wrote CEQA clearance for a new community park; and facilitated the preparation of an opportunity and constraints analysis for the realignment of a major drainage ditch. (January 1993 to October 1993)

Contract Planner - City of Sausalito's Design Review Board. Conducted design reviews and made presentations to Design Review Board. (January 1988 to June 1988)

Senior Planner - Marin County Planning Department. Responsible for the processing of Master Plans, Specific Plans, Subdivisions, Design Reviews, Use Permits and Variances; review of building permits, public information and land divisions; and presentations to Design Review Boards, Planning Commission and Board of Supervisors. Prepared a Community Plan Update involving numerous community workshops and public hearings. (June 1984 to December 1986)

Assistant Planner - City of Clearlake. Responsible for reviewing all building and planning applications to assure conformance with city codes and regulations; assisting the public with planning-related matters including zoning. Use Permits, Variances, Subdivisions, Lot Line Adjustments, reversions to acreage, business licenses, and specific development standards. (August 1981 to June 1984)

TEACHING EXPERIENCE

Instructor - University of California Extension Services. Conducted a one-day course through the University of California Extension Services on small town planning, focusing on how small towns can proactively address economic development, growth pressures, environmental concerns, and maintaining small town character. (1992 and 1994)

EDUCATION

Bachelor of Science - Conservation of Natural Resources, with an emphasis in City and Regional Planning, University of California, Berkeley. (1980)

University of California Extension Services - Certificate program courses in Transit Oriented Development, Pedestrian Oriented Development and Traditional Neighborhood Design. (1993-1994)

University of California Extension Services - Certificate program courses in computer graphics, including Photoshop, Pagemaker, Illustrator and Truespace. (1995-1996)

DECLARATION OF
James Brewster Birdsall

I, **J. BREWSTER BIRDSALL** declare as follows:

1. I am presently employed by **ASPEN ENVIRONMENTAL GROUP**, a contractor to the California Energy Commission, Systems Assessment and Facilities Siting Division, as a **SENIOR ASSOCIATE**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **AIR QUALITY**, for the **BLYTHE ENERGY PROJECT PHASE II,** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 4/5/05 Signed: JBrBirdsall

At: San Francisco, California

Aspen
Environmental Group

BREWSTER BIRDSALL, P.E., QEP
Senior Associate, Air Quality and Engineering

ACADEMIC BACKGROUND
M.S., Civil Engineering, Colorado State University, 1993
B.S., Mechanical Engineering, Lehigh University, 1991

PROFESSIONAL EXPERIENCE

Mr. Birdsall is an environmental scientist who specializes in air quality and noise analyses for land development related projects and air quality risk assessments. He has nine years of consulting experience with expertise in environmental impact assessment under the California Environmental Quality Act (CEQA), National Environmental Policy Act (NEPA), and the Clean Air Act. His focus is on air permitting, and air quality and noise-impact modeling, which includes field monitoring for traffic and other community noise sources.

Aspen Environmental Group — 2001 to present

Mr. Birdsall's project experience at Aspen includes the following:

Technical Studies for CEC Contract – Review of Power Plant AFCs. Mr. Birdsall assists the California Energy Commission (CEC) as a technical specialist by reviewing and providing testimony on Applications for Certification (AFC) for new power plants throughout California.

- **Tesla Power Plant.** Lead technical staff for air quality assessment and analyst of visible plumes for new 1,120 MW combined cycle power plant and 11-mile recycled water pipeline in rural eastern Alameda County near Tracy.
- **Inland Empire Energy Center.** Lead technical staff for air quality assessment for new 670 MW combined cycle power plant near Romoland in Riverside County.
- **Palomar Energy.** Lead technical staff for air quality assessment and supporting staff for cooling system studies for new 540 MW combined cycle power plant in northern San Diego County.
- **Kings River Conservation District Peaking Power Plant.** Lead technical staff for air quality assessment of new 97 MW simple cycle power plant in Fresno County.
- **Avenal Energy.** Lead technical staff for air quality assessment and analyst of visible plumes for large new combined cycle power plant near Avenal in Kings County.
- **Blythe Energy Project Phase II.** Lead technical staff for air quality assessment for new 520 MW combined cycle power plant and affiliated 118-mile transmission line, in the Mojave Desert and Coachella Valley of Riverside County.
- **Russell City Energy Center.** Lead technical staff for noise assessment of new 600 MW combined cycle power plant adjacent to shoreline recreational areas in Hayward.
- **Los Esteros Critical Energy Facility.** Lead technical staff for noise assessment and analyst of visible plumes for new 180 MW simple cycle power plant adjacent to recreational areas in San Jose.

- **Environmental Performance Report.** Technical review and editorial assistance for environmental portion of the first Integrated Energy Policy Report for the Governor and Legislature.
- **Air Quality Compliance.** Technical staff for analysis of modifications to permit conditions at the Moss Landing Power Plant. Prepared independent analysis of permit requirements and environmental consequences of increasing the capacity of the Midway-Sunset Cogeneration Project.
- **Alternative Cooling Technology Studies.** Supporting staff for analyses of dry cooling and hybrid cooling alternatives for the Cosumnes Power Plant and Palomar Energy Project. Coordinated and edited documentation from design engineers and other specialists.

For the **California Public Utilities Commission**:

- **San Onofre Nuclear Generating Station and Diablo Canyon Power Plant, Steam Generator Replacement Projects.** Currently serving as Deputy Project Manager for Environmental Impact Reports on the proposed improvements to these controversial nuclear power plants. Preparing certain administrative and technical portions of reports and coordinating the environmental documents with team of analysts.
- **Miguel-Mission 230 kV #2 Transmission Line.** Conducted the air quality and noise review for a system that would reduce transmission constraints between San Diego County and generators within the U.S. and Mexico. Provided oversight of the engineers studying impacts to traffic and transportation and the transmission system design.
- **Jefferson-Martin 230 kV Transmission Line.** Prepared air quality and noise studies for construction and operation of a 27-mile transmission line through urban and rural San Mateo County. The project is proposed to meet the projected electric demand in the Cities of Burlingame, Millbrae, San Bruno, South San Francisco, Brisbane, Colma, Daly City, and San Francisco.
- **Viejo System Transmission Project.** Prepared air quality, noise, and traffic analyses for construction of a controversial transmission improvement project in suburban south Orange County.
- **Looking Glass Networks Telecommunications Project.** Prepared the air quality and noise analyses for this Initial Study/Mitigated Negative Declaration (IS/MND) evaluating proposed fiber optic connections throughout the San Francisco Bay and Los Angeles areas, and developed programmatic mitigation measures for implementation of the metropolitan area network.

Presidio Trust, Presidio of San Francisco. Provided impact analysis for demolition, rehabilitation, and infill construction within the Public Health Service Hospital District, within the Golden Gate National Recreation Area and adjacent to sensitive San Francisco residences. Provided technical support and peer review of noise and vibration analyses related to the Doyle Drive Reconstruction through the Presidio of San Francisco. Involved protecting natural sounds consistent with National Park Service policy.

California State Lands Commission, Monterey Accelerated Research System Cabled Observatory. Providing technical analysis of air quality and noise effects of installing new underwater equipment in Monterey Bay. Supporting efforts of marine biologists with analysis of underwater noise.

California State Lands Commission, Concord-Sacramento Pipeline. Provided technical analysis of air quality and noise effects of constructing a new 20-inch, 70-mile petroleum products pipeline, including upgrades to storage tank facilities in Concord and distribution systems in West Sacramento.

California Department of Water Resources, Piru Creek Erosion Repairs and Bridge Seismic Retrofit Project. Provided assessment of air quality and noise impacts for construction of upgrades.

Ventura County Resource Conservation District, Casitas Springs *Arundo Donax* Removal Demonstration Project. Prepared estimates of community noise impacts and air quality assessment for cutting and removing non-native plants for improving flood control along the Ventura River.

Technical Support for U.S. Army Corps of Engineers. Analyzed construction noise and air quality effects and described applicability of general conformity rule for various flood control improvements in Arizona and Southern California.

Technical Support for Los Angeles Unified School District. Provided technical analysis of air quality and noise effects for school expansion, play area expansion, and temporary classroom projects, including reviews of cumulative, regional air quality consequences of temporary projects.

EIP Associates **1998 to 2001**

As a Senior Environmental Scientist at **EIP Associates**, Mr. Birdsall performed comprehensive analyses of air quality and noise impacts for Environmental Impact Reports/Statements and independent studies. His projects at EIP included:

- **Bay Area Rapid Transit District, Oakland Airport Connector EIS/EIR.** Prepared noise impact evaluation and mitigation strategies. Conducted community noise monitoring and assessment according to Federal Transit Administration methodology.
- **Presidio Trust Implementation Plan EIS and Letterman Complex Supplemental EIS.** Prepared community noise impact assessment and traffic noise mitigation strategies. Air quality management policy consistency analysis. The plan was awarded the 2003 Outstanding Land Use Plan from the Association of Environmental Professionals.
- **San Francisco International Airport, Offshore Runway Construction Concepts, AGS Design Team.** Conducted preliminary environmental review of design and construction concepts for runway expansion. Prepared emission control strategies for general conformity rule.
- **Sacramento Metropolitan Airport Master Plan EIS/EIR, Sacramento County Department of Environmental Review and Assessment.** Baseline emission inventory and regulatory constraints.
- **Desert Resorts Regional Airport, Thermal, Riverside County.** Emission inventory and general conformity determination for runway extension and taxiway improvements.
- **San Joaquin Area Flood Control Agency, Stockton Areawide Flood Control Projects.** Reviewed emission inventories and retroactive general conformity rule applicability for construction activities.
- **Alameda County Flood Control and Water Conservation District, Zone 7, Altamont Water Treatment Plant EIR.** Analyzed air quality and community noise effects of three potential water plant sites in remote eastern Alameda County.
- **Santa Clara Valley Water District, Coyote Watershed, Lower Silver Creek Project.** Analyzed air quality and community noise effects for Initial Study/Environmental Assessment of constructing flood control improvements and habitat restoration.
- **University of California, Davis.** Prepared campuswide health risk assessment update, which included toxic air contaminant emission inventory and dispersion modeling using ISC.

- **University of California, Berkeley.** Prepared initial air quality and noise technical studies for Long Range Development Plan Update EIR and analyses for Northeast Quadrant Science and Safety Project (Stanley Hall replacement building) EIR.
- **Merced County, Draft University Community Plan.** Prepared air quality and noise background studies and policy discussion papers for the new Merced Campus of the University of California.
- **Allegro Jack London Square Project, SNK Development.** Provided expert testimony on the pile driving noise impacts to residents in a revitalized, high-density City of Oakland neighborhood. Conducted field surveys with City Staff and evaluated compliance with City noise ordinance.
- **Maranatha High School and Playing Fields Project, City of Sierra Madre.** Prepared the community noise technical study for a new private high school with outdoor amphitheater and athletic facilities. Characterized noise from events to determine impact level on sensitive residential community.
- **State Route 275 Modification Project, City of West Sacramento.** Prepared noise technical studies on the realignment of the State Route 275 Modification Project. Required assessment of new traffic noise impacts caused by rerouting traffic to grade level in close proximity of existing sensitive land uses and identification of feasible measures to insulate lodging uses.
- **City of Mountain View, Whisman Road Transit Oriented Development MND.** Deputy Project Manager for Negative Declaration related to high-density office development at the Middlefield-Ellis-Whisman Superfund Site. Prepared various technical sections, managed traffic subconsultant, and coordinated preparing the environmental documents with the city staff.

Trinity Consultants — 1994 to 1998

Mr. Birdsall prepared compliance strategies, evaluated modeled impacts, and negotiated air permits while a Project Supervisor at **Trinity Consultants**, an environmental firm specializing in air quality.

- **Browning-Ferris Gas Services.** Coordinated nationwide Title V program implementation, secured numerous new source and operating permits, supported rollout of federal new source performance standards for municipal solid waste landfills and landfill gas to energy facilities.
- **Newmont Mining Joint Venture, Batu Hijau Project.** Environmental impact studies for open-pit metallic mineral mining facility and independent power production facility. Included noise assessment for "greenfield" power plant and air quality impacts evaluation in complex, coastal terrain.
- **Questar Pipeline, TransColorado Pipeline Project.** Secured new source permits for air quality effects related to construction and operation of major natural gas pipeline including compressor stations.
- **Coastal Field Services, Altamont Gas Plant.** Negotiated Title V operating permits for upstream natural gas processing plant and associated field compressor stations.
- **Solvay Soda Ash Joint Venture.** Developed particulate matter modeling protocol with State agency.
- **Potlatch Corporation.** Facilitywide emission inventory and permitting for a wood products plant. Included regionwide analyses of ambient air quality standards and resolving existing modeled violations.

NOISE IMPACT ASSESSMENT MODELS

- Federal Highway Administration Traffic Noise Model
- California Department of Transportation Traffic Noise Model (SOUND32)
- FTA Transit Noise Assessment and Mitigation Methodology

AIR QUALITY MODELING EXPERTISE

MVEI/EMFAC; URBEMIS; CALINE4; SCREEN; ISC; CTDM; TANKS; Landfill Gas Emissions Model.

ADDITIONAL TRAINING AND COURSES

- Fundamentals of Noise and Vibration for the California Energy Commission
- Expert Witness Training, California Energy Commission
- Co-Instructor, Air Permitting Issues for Municipal Solid Waste Landfills, Trinity Consultants
- Fundamentals of New Source Review Workshop, Air and Waste Management Association
- Title V and Compliance Assurance Monitoring Workshops, Air and Waste Management Association
- NATO Advanced Studies Institute, Wind Climates in Cities

PROFESSIONAL AFFILIATIONS AND AWARDS

- Professional Engineer (Mechanical, California #32565)
- Qualified Environmental Professional, Institute of Professional Environmental Practice (#03030005)
- 2001 Outstanding Performance Award presented by the California Energy Commission
- Air and Waste Management Association since 1994

PUBLICATIONS

Smith, P.J., J.B. Birdsall, and P.E. Delamater. "A Discussion of Air Permitting Issues for Landfill Gas-To-Energy Projects." 88th Annual Meeting and Exhibition of the Air and Waste Management Association, San Antonio, Texas, 1995.

Meroney, R.N., D.E. Neff, and J.B. Birdsall. "Wind-Tunnel Simulation of Infiltration Across Permeable Building Envelopes: Energy and Air Pollution Exchange Rates." 7th International Symposium on Measurement and Modeling of Environmental Flows. International Mechanical Engineering Congress and Exposition, San Francisco, California, 1995.

Birdsall, J.B. and R.N. Meroney. "Model Scale and Numerical Evaluation of Tracer Gas Distribution Due to Wind-Forced Natural Ventilation." 9th International Conference on Wind Engineering, New Delhi, India, 1995.

Birdsall, J.B. Physical and Numerical Simulation of Wind-Forced Natural Ventilation, MS Thesis, Colorado State University, Fort Collins, Colorado, 1993.

DECLARATION OF
Lisa A. Blewitt

I, **Lisa Blewitt** declare as follows:

1. I am presently employed by Aspen Environmental Group, a contractor to the California Energy Commission, in the Agoura Hills office as an associate in engineering and physical sciences.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **VISUAL RESOURCES** (VISUAL PLUME ANALYSIS), for the **BLYTHE ENERGY PROJECT PHASE II** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 23, 2005 Signed: Lisa Blewitt

At: Agoura Hills, California

LISA A. BLEWITT
Associate Engineer/Physical Scientist

ACADEMIC BACKGROUND
B.S., Chemical Engineering, University of California, Santa Barbara, 1996

PROFESSIONAL EXPERIENCE

Miss Blewitt is a chemical engineer with experience in air, plume and noise analysis. Prior experience includes refinery and power plant design. Project management experience includes helping manage the Aspen team (Aspen employees plus all subcontractors) for several California Energy Commission (CEC) projects, and support on various proposals.

Aspen Environmental Group — August 2001 to present

Miss Blewitt's project experience at Aspen includes the following:

California Energy Commission (CEC): Miss Blewitt performed plume analysis and/or air quality analysis on several projects to support the Staff Assessments for the CEC's CEQA equivalent review process. She helps manage the Aspen team as Power Plant Coordinator (PPC). Coordination of the Aspen team with CEC project managers includes providing up-to-date information to all members of the team, identifying key issues, and preparing monthly progress reports. She also manages the Aspen team as the overall Aspen PPC for all CEC projects by providing weekly progress reports to all Aspen PPC's .

- **Avenal:** AFC for 600 MW combined cycle plant located in Avenal, Kings County. Miss Blewitt performed the plume analysis for the cooling tower, heat recovery steam generators (HRSGs), and auxiliary boiler.
- **Blythe 2:** Aspen Team Power Plant Coordinator to support the Staff Assessment of the AFC for a 520 MW combined cycle power plant located entirely within the previously approved Blythe Energy Project facility boundaries west of the City of Blythe, Riverside County. Miss Blewitt will be performing the plume analysis. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.
- **Central Valley Energy Center:** Aspen Team Power Plant Coordinator to support the Staff Assessment of the AFC for a 1,060 MW combined cycle power generation facility located in the City of San Joaquin, Fresno County. Miss Blewitt assisted with the air quality analysis, and performed the plume analysis for the cooling tower, HRSGs, and auxiliary boiler. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.
- **Colusa CC:** AFC for a 500 MW combined cycle power generation facility located west of the City of Williams in Colusa County. Miss Blewitt assisted with the air quality analysis.
- **East Altamont:** AFC for a 1,100 MW combined cycle power generation facility located southeast of Tracy in Alameda County. Miss Blewitt assisted with the cooling tower plume analysis. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.

- **Henrietta:** AFC for a 91.4 MW simple cycle power plant to be located west of the City of Lemoore, in Kings County. Miss Blewitt assisted with the air quality analysis and performed the plume analysis for the HRSGs. This plant did not require a cooling tower.
- **Inland Empire:** AFC for a 670 MW combined cycle power plant to be located near the town of Romoland and Perris, within an unicorporated area of Riverside County. Miss Blewitt performed the plume analysis for the cooling tower, HRSGs, and auxiliary boiler.
- **Los Esteros Critical Energy Facility:** Aspen Team Power Plant Coordinator to support the Staff Assessment of the AFC for a 180 MW simple cycle peaking plant in San Jose, CA.
- **Magnolia:** AFC to add 250 MW of new generation at Magnolia Generation Power Plant in Burbank, CA. Miss Blewitt assisted in the air quality analysis and performed the plume analysis for the cooling tower and HRSGs. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.
- **Roseville Energy Facility:** AFC for 900 MW combined cycle power plant five miles northwest of downtown Roseville in Placer County. Miss Blewitt performed the plume analysis for the cooling towers.
- **SMUD Consumnes:** AFC for 1000 MW combined cycle power plant to be located at the Rancho Seco Nuclear Power Plant in Sacramento County. Miss Blewitt performed the plume analysis for the cooling towers and HRSGs.
- **South Star:** AFC for 100 MW simple cycle power plant (SS I) located in the Texaco South Midway-Sunset Oilfield, Kern County. Miss Blewitt assisted with the air quality analysis. Project cancelled.
- **Spartan:** Power Plant Coordinator for Aspen team to support the Staff Assessment of the AFC for a 96 MW simple cycle peaking plant in San Jose, CA. Project cancelled.
- **Tracy:** Aspen Team Power Plant Coordinator to support the Staff Assessment of the AFC for a 169 MW simple cycle power plant to be located southwest of the City of Tracy, in western San Joaquin County. Miss Blewitt also assisted with the air quality analysis and performed the plume analysis based on results from Spartan I Energy Center Project.
- **Vernon:** AFC for the Malburg Generating Station (MGS), a 120 MW combined cycle power plant to be located in the City of Vernon, Los Angeles County. Miss Blewitt performed the plume analysis for the cooling tower and HRSGs. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.

Los Angeles Unified School District (LAUSD): Miss Blewitt performed noise analysis and/or parking studies for the following projects.

- **Wonderland:** Three-story stick building classroom addition to an existing elementary school. Miss Blewitt attended a site visit to analyze the current project alternative, and provided an update to the project manager regarding the impact to issues previously identified for the original configuration. Miss Blewitt performed the noise analysis for the proposed project in October 2002.
- **Narbonne:** Portable additions to an existing high school. Miss Blewitt performed a parking study to determine baseline parking conditions prior to addition of new portables.
- **Wilson:** Portable additions to an existing high school. Miss Blewitt performed a parking study to determine baseline parking conditions prior to addition of new portables.

- **Reseda:** Portable additions to an existing high school. Miss Blewitt performed a noise analysis in October 2002 to determine the significance of noise impacts due to the addition of fifteen classroom buildings and two sanitary buildings on the existing school campus. Coordinated with staff to incorporate all District comments into the Initial Study, and prepared the draft Mitigated Negative Declaration.

Proposals: Miss Blewitt assisted in the development of the following proposals:

- **Department of Water and Power On-Call:** Miss Blewitt coordinated the subcontractors including collecting all resumes, project descriptions, firm descriptions, and references.
- **Miguel Mission:** Miss Blewitt coordinated the subcontractors including collecting all letters of participation, conflict of interest statements, disclosure tables, resumes, project descriptions, technical approaches, and references.

Fluor Daniel, Inc. **August 1996 to July 2001**

Miss Blewitt was a Process Engineer at Fluor Daniel, Inc. in Aliso Viejo, CA from August 1996 to July 2001. She did process design work for both refineries and power plants.

- **Occidental Chemical Taft Cogeneration Project:** Worked with Duke Fluor Daniel to independently develop the design of multiple process systems including wastewater treatment, storm water, potable water, hydrogen and natural gas. Coordinated and discussed design issues with civil/structural, architectural, piping, mechanical, project engineers and the client to develop and optimized, cost-effective design. Developed process flow diagrams (PFD) and piping and instrument diagrams (P&ID) to meet all safety and operability requirements set by the client and industry standards. Confirmed piping layouts met system hydraulic requirements for proper operation considering design and alternate operating cases.
- **Georgia-Pacific Steam Reformer Project:** Lead flue gas recycle study to determine operating requirements for combustion in pulse heaters.
- **Syncrude Canada Upgrader Expansion (UE-1) Project:** Prepared the Design Basis Specification and defined the revamp modifications required to debottleneck a Naphtha Hydrotreater Plant. Conducted the PFD Review for design approval with the client in Fort McMurray, Alberta, Canada. Simulated the Naphtha Hydrotreater Plant. Completed multiple configuration studies to determine the best configuration for UE-1.

ADDITIONAL TRAINING AND COURSES:
Engineer-In-Training Certificate
UCSB Extension 2-day class - Preparing CEQA/NEPA Documents
UCSB Extension Project Management Professional Certification Program (9/02 - 06/03) – 16 units total

PROFESSIONAL AFFILIATIONS: UCSB Alumni Association

DECLARATION OF
Jim Buntin

I, **Jim Buntin**, declare as follows:

1. I am presently employed by Brown-Buntin Associates, Inc. as a Principal Consultant under contract with the California Energy Commission Energy Facilities Siting and Environmental protection Division.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **NOISE** for the Blythe Energy Project Phase II, based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 4/12/05 Signed: _____

At: Fair Oaks, California

JIM BUNTIN

Principal
Brown–Buntin Associates, Inc.

Mr. Buntin is a founding partner of Brown–Buntin Associates, Inc. (BBA), and manages the firm's Northern California office. He has performed a wide variety of acoustical studies, including analyses of airport/aircraft noise, traffic noise, industrial noise sources and architectural acoustics. His technical skills include aviation, industrial and traffic noise assessment, and development and interpretation of noise exposure criteria. He was awarded Board Certification by the Institute of Noise Control Engineering in 1985.

Mr. Buntin began his involvement in noise assessment in 1972 in the public sector. In 1980, Mr. Buntin was Director of the Center for a Quiet Environment at U.C. Berkeley, where he provided technical assistance and training in environmental noise assessment in the western United States. Since the founding of Brown–Buntin Associates, Inc. in 1981, Mr. Buntin has managed hundreds of noise analyses, including:

- Airport noise studies including FAR Part 150 Noise Compatibility Programs, quarterly noise monitoring and ongoing technical support, environmental documents, and noise contour preparation.
- Environmental noise assessments for project EIR/EIS documents in California and Nevada.
- Preparation of Noise Elements of the General Plan for numerous cities and counties in California.
- Noise assessments for a wide variety of proposed industrial, mining, and stationary sources.
- Staff noise assessments for power plant projects in California, for the California Energy Commission.

PROFESSIONAL AFFILIATIONS:

- Board Certified Member, Institute of Noise Control Engineering.
- Member, Acoustical Society of America.
- Member, Aircraft Noise Subcommittee, National Research Council, Transportation Research Board.
- Member, ASTM Committee E33 (Environmental Acoustics).

PUBLICATIONS AND PRESENTATIONS:

Fundamentals of Aircraft Noise, Noise 101, Oakland Airport Community Noise Management Forum, Oakland, California, November 2002 and October 2004.

Sound Insulation Assessment Using Aircraft Single Event Noise Levels, 2nd Annual AAAE/Quieter Home Sound Insulation Symposium, Palm Springs, California, October 20, 2002.

Helicopter Noise Assessment Issues, N.O.I.S.E Aviation Noise Symposium, Portland, Oregon, July 20, 2001.

Gas Turbine Noise Mitigation for a Residential Development, 140th Meeting of the Acoustical Society of America, Anaheim, California, December, 2000.

Comparison of Predicted Aircraft Noise Levels Using INM Versions 4.11 and 5.01, Noise-Con 96, Seattle Washington, September 1996

Modeling of Enhanced Sound Propagation at a California Airport, Inter-Noise 94, Yokohama, Japan, August, 1994.

Use of a Synthesized Aircraft Noise Spectrum for Residential Sound Insulation Evaluation, National Transportation Research Board, 72nd Annual Meeting, January, 1993.

Criteria for Acceptable Aircraft Noise Exposures in Classrooms, Inter–Noise 89, Newport Beach, California, December, 1989.

Criteria for Low Frequency and Infrasound from Wind Energy Farms in Kern County, 112th Meeting of the Acoustical Society of America, Anaheim, California, December, 1986.

Seminars in Environmental Noise Control, California Office of Noise Control Community Noise Conference, Asilomar, California, 1982, 1985, 1987, 1990.

EDUCATION:

- B.A., Zoology, 1968, University of California at Los Angeles.
- Graduate courses in Public Administration, California State University at Bakersfield.
- Graduate courses in Environmental Noise: University of California at Berkeley, Santa Cruz and San Francisco.

DECLARATION OF
DAVID FLORES

I, **David Flores** declare as follows:

1. I am presently employed by the California Energy Commission in the **Land Use and Traffic and Transportation Unit** of the Office of the Systems Assessments and Facilities Siting Division as a **Planner II**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Land Use**, for the **Blythe Energy Project Phase II** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 23, 2005 Signed: _____

At: Sacramento, California

DAVID FLORES

WORK EXPERIENCE

Sept. 1998 to Present — **Planner 2.** California Energy Commission, Energy Facilities Siting and Protection Division.

- Provide technical analysis of proposed energy planning, conservation, and development programs on land use, visual and traffic and transportation resources. Specific tasks include the analysis of potential impacts, identification of suitable mitigation measures, preparation of testimony, and project monitoring to ensure compliance with local, state and federal environmental laws and regulations.

March 29,1988 to September 12, 1998 — **Senior Planner.** County of Yolo Planning and Public Works Department

Senior Planner - Current and Advanced Planning (Resources Management and Planning)

Responsibilities included the following:

Administered the establishment of Planning schedules and timeframe completion schedules; Administration and staff support to Planning Commission and Board of Supervisors; Staff support and liaison to citizen's committees. Preparation of Environmental documents (Negative Declarations, preparation of Environmental Impact Reports and Categorical Exemptions) in accordance with State and Federal Regulations.

PLANNING ACHIEVEMENTS

- Principal staff involved in development of the County Right to Farm and Williamson Act/ Blue Ribbon Ordinances.
- Staff liaison to citizen committees for the communities of Yolo County
- Substantial experience in working successfully with community organizations and committees on controversial projects.
- Responsible for the administration of the California Environmental Quality Act (CEQA) for all matters going before the Planning Commission and Board of Supervisors.

EDUCATION

California State University @ Sacramento
University of California @Davis
Major: Environmental Studies
Minor: Business Administration

Continuing education has included: Writing for Managers, CEQA Updates, Managing the Office, CEQA Update, Subdivision Map Act, General Plan Update

DECLARATION OF
Alvin J. Greenberg, Ph.D.

I, **Alvin J. Greenberg** declare as follows:

1. I am presently a consultant to the California Energy Commission, Energy Facilities Siting and Environmental Protection Division.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on the **General Conditions COM-8** section for the **Blythe Energy Project II** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: April 25, 2005 Signed: Alvin J. Greenberg

At: Sacramento, California

DECLARATION OF
Alvin J. Greenberg, Ph.D.

I, **Alvin J. Greenberg** declare as follows:

1. I am presently a consultant to the California Energy Commission, Energy Facilities Siting and Environmental Protection Division.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Hazardous Materials Management and Worker Safety/Fire Protection** sections for the **Blythe Energy Project II** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: April 7, 2005 Signed: Alvin J. Greenberg

At: Sacramento, California

Risk Science Associates

121 Paul Dr., Suite A, San Rafael, Ca. 94903-2047
415-479-7560 fax 415-479-7563
e-mail agreenberg@risksci.com

Name & Title: **Alvin J. Greenberg, Ph.D., FAIC, REA, QEP**
Principal Toxicologist

Dr. Greenberg has had over two decades of complete technical and administrative responsibility as a team leader for hazardous waste site characterization, preparation of human and ecological risk assessments, air quality assessments, interaction with regulatory agencies in obtaining permits, hazardous materials handling and risk management prevention, infrastructure vulnerability assessments, conducting lead surveys and studies, with particular expertise in the assessment of dioxins, lead, diesel exhaust, petroleum hydrocarbons, and the intrusion of subsurface contaminants into indoor air. Dr. Greenberg's expertise in risk assessment has led to his appointment as a member of several state and federal advisory committees, including the California EPA Advisory Committee on Stochastic Risk Assessment Methods, the US EPA Workgroup on Cumulative Risk Assessment, the Cal/EPA Peer Review Committee of the Health Risks of Using Ethanol in Reformulated Gasoline, the California Air Resources Board Advisory Committee on Diesel Emissions, the Cal/EPA Department of Toxic Substances Control Program Review Committee, and the DTSC Integrated Site Mitigation Committee. Dr. Greenberg is the former Chair of the Bay Area Air Quality Management District Hearing Board, a former member of the State of California Occupational Health and Safety Standards Board (appointed by the Governor), and former Assistant Deputy Chief for Health, California OSHA. And, since the events of 9/11, Dr. Greenberg has been the lead person for developing vulnerability assessments and power plant security programs for the California Energy Commission.

Years Experience: 25

Education:

B.S. 1969 Chemistry, University of Illinois Urbana

Ph.D. 1976 Pharmaceutical/Medicinal Chemistry, University of California, San Francisco

Postdoctoral Fellowship 1976-1979 Pharmacology/Toxicology, University of California, San Francisco

Postgraduate Training 1980 Inhalation Toxicology, Lovelace Inhalation Toxicology Research Institute, Albuquerque, NM

Professional Registrations:

Board Certified as a Qualified Environmental Professional (QEP)
California Registered Environmental Assessor (REA)

Fellow of the American Institute of Chemists (FAIC)

Professional Affiliations:

Society for Risk Analysis
Air and Waste Management Association
Society of Environmental Toxicology and Chemistry
American Chemical Society
American Association for the Advancement of Science
National Association of Hearing Officials
National Fire Protection Association

Technical Boards and Committee Memberships - Present:

Squaw Valley Technical Review Committee
(appointed 1986)

Technical Boards and Committee Memberships - Past:

July 1996 – March 2002
Member, Bay Area Air Quality Management District Hearing Board
(Chairman 1999-2002)

September 2000 – February 2001
Member, State Water Resources Control Board Noncompliant Underground Tanks Advisory Group

January 1999 – June 2001
Member, California Air Resources Board Advisory Committee on Diesel Emissions

January 1994 - September 1999
Vice-Chairman, State Water Resources Control Board Bay Protection and Toxic Cleanup Program Advisory Committee

September 1998
Member, US EPA Workgroup on Cumulative Risk Assessment

April 1997 - September 1997
Member, Cal/EPA Private Site Manager Advisory Committee

January 1986 - July 1996
Member, Bay Area Air Quality Management District Advisory Council
(Chairman 1995-96)

January 1988 - June 1995
Member: California Department of Toxic Substance Control Site Mitigation Program Advisory Group

January 1989 - February 1995
Member: Department of Toxics Substances Control Review Committee, Cal-EPA

October 1991 - February 1992
Chair: Pollution Prevention and Waste Management Planning Task Force of the Department of Toxics Substances Control Review Committee, Cal-EPA

September 1990 - February 1991
Member: California Integrated Waste Management Board Sludge Advisory Committee

September 1987 - September 1988
ABAG Advisory Committee on Regional Hazardous Waste Management Plan

March 1987 - September 1987
California Department of Health Services Advisory Committee on County and Regional Hazardous Waste Management Plans

January 1984 - October 1987
Member, San Francisco Hazardous Materials Advisory Committee

March 1984 - March 1987
Member, Lawrence Hall of Science Toxic Substances and Hazardous Materials Education Project Advisory Board

Jan. 1, 1986 - June 1, 1986
Member, Solid Waste Advisory Committee, Governor's Task Force on Hazardous Waste

Jan. 1, 1983 - June 30, 1985
Member, Contra Costa County Hazardous Waste Task Force

Sept. 1, 1982 - Feb. 1, 1983
Member, Scientific Panel to Address Public Health Concerns of Delta Water Supplies, California Department of Water Resources

Present Position

January 1983- present
Owner and principal with Risk Sciences Associates, a Marin County, California, environmental consulting company specializing in multi-media human health and ecological risk assessment, air pathway analyses, hazardous materials management-infrastructure security, environmental site assessments, and litigation support for toxic substance exposure cases.

Previous Positions

Jan. 2, 1983 - June 12, 1984
Member, State of California Occupational Safety and Health Standards Board (Cal/OSHA), appointed by the Governor

Aug. 1, 1979 - Jan. 2, 1983
Assistant Deputy Chief for Health, California Occupational Safety and Health Administration

Feb. 1, 1979 - Aug. 1, 1979
Administrative Assistant to Chairperson of Finance Committee, Board of Supervisors, San Francisco

Jan. 1, 1976 - Feb. 1, 1979
Research Pharmacologist and Postdoctoral Fellow, Department of Pharmacology and Toxicology, School of Medicine, University of California, San Francisco

Jan. 1, 1975 - Dec. 31, 1975

Acting Assistant Professor, Department of Pharmaceutical Chemistry, University of California, San Francisco

Experience

General

Dr. Greenberg has been a consultant in Human and Ecological Risk Assessment, Occupational Health, Toxicology, Hazardous Materials Management and Security, Hazardous Waste Site Characterization and Toxic Substances Control Policy for over 25 years. He has broad experience in the identification, evaluation and control of health and environmental hazards due to exposure to toxic substances. His experience includes Community Relations Support and Risk Communication through experience at high-profile sites and presentations at professional society meetings.

He has considerable experience in the review and evaluation of exposure via the air pathway - particularly to emissions from power plants and diesel exhaust - and a thorough knowledge of the regulatory requirements through his experience at Cal/OSHA, the BAAQMD Hearing Board, as a consultant to the California Energy Commission, and in preparing such assessments for local government and industry. He has assessed exposures to diesel exhaust during construction and operations of stationary and mobile sources and has testified at evidentiary hearings numerous times on this subject.

He served for over five years as the Vice-chair of the California State Water Resources Control Board Advisory Committee convened to address toxic substances in sediments in bays, rivers, and estuaries. He has also conducted numerous ecological risk assessments and characterizations, including those for marine and terrestrial habitats.

Since the events of 9/11, Dr. Greenberg has taken the lead for the California Energy Commission in developing a power plant vulnerability assessment methodology and model power plant security plan. He also assisted the CEC in the preparation of a "background" report on the risks and hazards of siting LNG terminals in California and consulted for the City of Vallejo on a proposed LNG terminal and storage facility at the former Mare Island Naval Shipyard. In August 2004, a team of experts led by Dr. Greenberg was awarded an 18-month contract by the State of Hawaii to update and improve the state's Energy Emergency Preparedness Plan and make recommendations for increased security of critical energy infrastructure on this isolated group of islands.

Dr. Greenberg has extensive experience in data collection and preparation of human and ecological risk assessments on numerous military bases and industrial sites with Cal/EPA DTSC and RWQCB oversight. He has also been retained to provide technical services to the Cal/EPA Department of Toxic Substances Control (preparation of human health risk assessments) and the Office of Environmental Health Hazard Assessment (review and evaluation of air toxics health risk assessments and preparation of profiles describing the acute and chronic toxicity of toxic air contaminants). He has also conducted several surveys of sites containing significant lead contamination from various sources including lead-based paint, evaluated potential occupational

exposure to lead dust and fumes in industrial settings, prepared numerous human health risk assessments of lead exposure, and prepared safety and health plans for remedial investigation of lead oxide contaminated soil at DOD facilities.

Dr. Greenberg is also a recognized expert on the requirements of California's Proposition 65 and has served as an expert on Prop. 65 litigation.

Air Pathway Analysis

Dr. Greenberg has prepared numerous Air Pathway Analyses and human health risk assessments, evaluating exposure at numerous locations in California, Hawai'i, Oregon, Minnesota, Michigan, and New York. He is experienced in working with Region IX EPA, the State of California DTSC, and the Hawai'i Department of Health Clean Air Branch in the application of both site-specific and non site-specific health risk assessment criteria.

Examples

Human Health Risk Assessment for the Open Burn/Open Detonation Operation at McCormick Selph, Inc., Hollister, Ca. (June 2003)

Air Quality and Human Health Risk Assessment for the Royal Oaks Industrial Complex, Monrovia, Ca. (January 2003)

Human Health Risk Assessment and Indoor Vapor Intrusion Assessment for the former Pt. St. George Fisheries Site, Santa Rosa, Ca. (October 2002)

Human Health Risk Assessment for the former Sargent Industries Site, Huntington Park, Ca. (July 2001)

Ballard Canyon Air Pathway Analysis and Human Health Risk Assessment, Santa Barbara County, Ca. (September 2000)

Health Risk Assessment Due to Diesel Train Engine Emissions, Oakland, Ca. (June 1999)

The Avila Beach Health Study Phase 1: Reconnaissance Sampling Findings, Conclusions, and Recommendations. (July 1997) Volume 1: Baseline Human Health Risk Assessment. (May 1998)

The Avila Beach Health Study Phase 1, Volume 2: Environmental Monitoring. (May 1998)

Health Risk Assessment and Air Pathway Analysis for the Ballard Canyon Landfill, Santa Barbara County, Ca. (March 1999)

Human Health Risk Assessment, Teledyne Ryan Aeronautical, McCormick Selph Ordnance. Hollister, California. (December 1996)

Initial Phase Human Health Risk Assessment, Teledyne Inc., San Diego, Ca. (October 1996)

Human Health Risk Assessment for Current and Proposed Expanded Class II and Class III Operations at the Altamont Sanitary Landfill, Alameda County, Ca. (March, 1993)

Focused Ecological Risk Characterization, Hawaiian Electric Company, Keahole Generating Station Expansion, Hawai'i (June 1993)

Human Health Risk Assessment for the Proposed Palima Point Space Launch Complex, prepared for the Hawai'i Office of Space Industry (April 1993)

Ecological Risk Assessment for the Proposed Palima Point Space Launch Complex, prepared for the Hawai'i Office of Space Industry (March 1993)

Human Health Risk Assessment Due to Emissions from a Medical Waste Incinerator, prepared for Kauai Veterans Memorial Hospital, Kauai, Hawai'i (1994)

Cancer Risk Assessment for the H-Power Generating Station, Campbell Industrial Park, Oahu, Hawai'i (1988)

Infrastructure Security

For the past three years, Dr. Greenberg has been trained by and is working with the Israeli company SB Security, LTD, the most experienced and tested security planning and service company in the world. Since the events of 9/11, Dr. Greenberg has been the lead person for developing vulnerability assessments and power plant security programs for the California Energy Commission (CEC). In taking the lead for this state agency, Dr. Greenberg has interfaced with the California Terrorism Information Center (CATIC) and provided analysis, recommendations, and testimony at CEC evidentiary hearings regarding the security of power plants within the state. These analyses include the preparation of vulnerability assessments and off-site consequence analyses addressing the use, storage, and transportation of hazardous materials, recommendations for security to reduce the threat from terrorist activities, perimeter security, site access by personnel and vendors, personnel background checks, management responsibilities for facility security, and employee training in security methods. Dr. Greenberg is the lead person in developing a model power plant security plan, vulnerability assessment matrix, and a security training manual for the CEC. The model security plan will be used by all power plants in California as guidance in developing and implementing security measures to reduce the vulnerability of California's energy infrastructure to terrorist attack. He has testified at several evidentiary hearings for the CEC on power plant security issues.

Sites with RWQCB and/or DTSC Oversight

Dr. Greenberg has specific experience in assessing human health and ecological risks at contaminated sites at the land/water interface, including petroleum contaminants, metals, and VOCs at several locations in California including Oxnard, Richmond, Avila Beach, Mare Island Naval Shipyard, San Diego, Hollister, San Francisco, Hayward, Richmond, the Port of San Francisco, and numerous other locations. He has used Cal/EPA methods, US EPA methods, and ASTM Risk Based Corrective Action (RBCA) and Cal/Tox methodologies. He is extremely knowledgeable about SWRCB and SF Bay RWQCB regulations on underground storage tank sites and with ecological issues presented by contaminated sediments including sediment

analysis, toxicity testing, tissue analysis, and sediment quality objectives. Dr. Greenberg served on the State Water Resources Control Board Bay Protection and Toxic Cleanup Program Advisory Committee from 1994 until the end of the program in 1999.

Dr. Greenberg experience on many of these contaminated sites has been as a consultant to local governments, state agencies, and citizen groups. He assisted the City and County of San Francisco in developing local ordinance requiring soil testing (Article 20, Maher ordinance) and hazardous materials use reporting (Article 21, Walker ordinance). He served as the City of San Rafael's consultant to provide independent review and evaluation of the site characterization and remedial action plan prepared for a former coal gasification site. He was a consultant to a citizen group in northern California regarding exposure and risks due to accidental releases from a petroleum refinery and assisted in the assessment of risks due to crude petroleum contamination of a southern California beach. He has prepared a number of risk assessments addressing crude petroleum, diesel and gasoline contamination, including coordinating site investigations, environmental monitoring, and health risk assessment for the County of San Luis Obispo regarding Avila Beach subsurface petroleum contamination. That high-profile project lasted for over one year and Dr. Greenberg managed a team of experts with a budget of $750,000. Another high-profile project included the preparation of an extensive comprehensive human and ecological risk assessment for the Hawaii Office of Space Industry on rocket launch impacts and transportation/storage of rocket fuels at the southern end of the Big Island of Hawaii. Dr. Greenberg's risk assessments were part of the EIS for the project. Dr. Greenberg is presently working on another high-profile project conducting Air Pathway Analysis of off-site and on-site impacts from landfill gas constituents, including indoor and outdoor air measurements, air dispersion modeling, flux chamber investigations, and health risk assessment for the County of Santa Barbara.

Dr. Greenberg has conducted RI/FS work, prepared health risk assessments, evaluated hazardous waste sites and hazardous materials use at numerous locations in California, Hawaii, Oregon, Minnesota, Michigan, and New York. He has considerable experience in the development of clean-up standards and the development of quantitative risk assessments for site RI/FS work at CERCLA sites, as well as site closures, involving toxic substances and petroleum hydrocarbon wastes. He is experienced in working with both Region IX EPA and the State of California DTSC in negotiating clean-up standards based on the application of both site-specific and non site-specific health and ecological based clean-up criteria. He has significant experience in the development of site chemicals of concern list, quantitative data quality levels, site remedial design, the site closure process, the design and execution of data quality programs and verification of data quality prior to its use in the decision making process on large NPL sites.

Examples

The Avila Beach Health Study Phase 1: Reconnaissance Sampling Findings, Conclusions, and Recommendations. (July 1997) Volume 1: Baseline Human Health Risk Assessment. (May 1998)
The Avila Beach Health Study Phase 1, Volume 2: Environmental Monitoring. (May 1998)

Health Risk Assessment and Air Pathway Analysis for the Ballard Canyon Landfill, Santa Barbara County, Ca. (March 1999)

Screening Human Health Risk Assessment, Calculation of Soil Clean-up Levels, and Aquatic Ecological Screening Evaluation, Galilee Harbor, Sausalito, Ca. (May 1998)

Health Risk Assessment Due to Diesel Train Engine Emissions, Oakland, Ca. (June 1999)

Health Risk Assessment for Residual Mercury at the Deer Creek Facility, 3475 Deer Creek Road, Palo Alto, California. (July 1997)

Phase 2 Human Health Risk Assessment, Teledyne Inc., San Diego, Ca. (February 1997)

Human Health Risk Assessment, Teledyne Ryan Aeronautical, McCormick Selph Ordnance. Hollister, California. (December 1996)

Initial Phase Human Health Risk Assessment, Teledyne Inc., San Diego, Ca. (October 1996)

Human Health Risk Assessment, Ecological Screening Evaluation, and Development of Proposed Remediation Goals for the Flair Custom Cleaners Site, Chico, California (January 1996)

Human Health Risk Assessment for the X-3 Extrudate Project at Criterion Catalyst, Pittsburg, Ca. (November 1994)

Screening Health Risk Assessment and Development of Proposed Soil Remediation Levels at Hercules Plant #3, Culver City, Ca. (July 1993)

Ecological Screening Evaluation for the Altamont Landfill, Alameda County, Ca. (June, 1993)

Focused Ecological Risk Characterization, Hawaiian Electric Company, Keahole Generating Station Expansion, Hawaii (June 1993)

Human Health Risk Assessment for the Proposed Palima Point Space Launch Complex, prepared for the Hawaii Office of Space Industry (April 1993)

Ecological Risk Assessment for the Proposed Palima Point Space Launch Complex, prepared for the Hawaii Office of Space Industry (March 1993)

Human Health Risk Assessment for Current and Proposed Expanded Class II and Class III Operations at the Altamont Sanitary Landfill, Alameda County, Ca.
(March, 1993)

Screening Health Risk Assessment for the Proposed Expansion of the West Marin Sanitary Landfill, Point Reyes Station, Ca.
(March, 1993)

Health Risk Assessment for the Proposed Expansion of the Forward, Inc. Landfill, Stockton, Ca. (September 14, 1992)

Health Risk Assessment for the Rincon Point Park Project, San Francisco, Ca. Prepared for Baseline Environmental Consulting and the San Francisco Redevelopment Agency. (August 10, 1992)

Health Risk Assessment for the South Beach Park Project, San Francisco, Ca. Prepared for Baseline Environmental Consulting and the San Francisco Redevelopment Agency. (August 10, 1992)

Screening Health Risk Assessment and Development of Proposed Soil and Groundwater Remediation Levels, Kaiser Sand and Gravel, Mountain View, Ca. Prepared for Baseline Environmental Consulting (January 30, 1992)

Development of Proposed Soil Remediation Levels for the Marine Corps Air-Ground Combat Center, 29 Palms, California (May 30, 1991)

Preliminary Health Risk Assessment for the City of Pittsburg Redevelopment Agency, Pittsburg, California (May 29, 1991)

Military Bases

Dr. Greenberg has experience in conducting assessments at DOD facilities, including RI/FS work, preparation of health risk assessments, evaluation of hazardous waste sites and hazardous materials use at the following Navy sites in California: San Diego Naval Base; Marine Corps Air-Ground Combat Center, 29 Palms; Mare Island Naval Shipyard, Vallejo; Treasure Island Naval Station, San Francisco, Hunters Point Naval Shipyard, San Francisco, and the Marine Corps Logistics Base, Barstow. He worked with the U.S. Navy and the U.S. EPA in the implementation of Data Quality Objectives (DQO's) at MCLB, Barstow.

Examples

Review and Evaluation of the Remedial Investigation Report and Human Health Risk Assessment for the U. S. Naval Station at Treasure Island, Ca. (June 1999)

Screening Health Risk Assessment for the Proposed San Francisco Police Department's Helicopter Landing Pad at Hunters Point Shipyard, San Francisco, Ca. (September 1997)

Development of Proposed Soil Remediation Levels for the Marine Corps Air-Ground Combat Center, 29 Palms, California (May 30, 1991)

Health Risk Assessment for the Chrome Plating Facility, Mare Island Naval Shipyard, Vallejo, California (October 24, 1988)

Background Levels and Health Risk Assessment of Trace Metals present at the Naval Petroleum Reserve No.1, 27R Waste Disposal Trench Area, Lost Hills, California (August 12, 1988)

RCRA Facility Investigation (RFI) Work Plan of Lead Oxide Contaminated Areas, Mare Island Naval Shipyard, Vallejo, California. Prepared in conjunction with Kaman Sciences Corp. (August 14, 1989)

Hazardous Waste and Solid Waste Audit and Management Plan, Mare Island Naval Shipyard, Vallejo, California. Prepared in conjunction with Kaman Sciences Corp. (July 3, 1989)

Water Quality Solid Waste Assessment Test (SWAT) Proposal RCRA Landfill, Mare Island Naval Shipyard, Vallejo, California. Prepared in conjunction with Kaman Sciences Corp. (October 31, 1988)

Waste Disposal Facilities, Waste Haulers, Waste Recycling Facilities Report, Mare Island Naval Shipyard, Vallejo, California. Prepared in conjunction with Kaman Sciences Corp. (September 22, 1988)

Sampling and Analysis Plan, Health and Safety Plan, Site Characterization of Lead Oxide Contaminated Areas, Mare Island Naval Shipyard, Vallejo, California. Prepared in conjunction with Kaman Sciences Corp. (September 2, 1988)

Air Quality Solid Waste Assessment Test (SWAT) Proposal, Mare Island Naval Shipyard, Vallejo, California. Prepared in conjunction with Kaman Sciences Corp. (August 25, 1988)

Occupational Safety and Health/Health and Safety Plans/Indoor Air Quality

Dr. Greenberg has significant experience in occupational safety and health, having directed the development, adoption, and implementation of over 50 different Cal/OSHA regulations, including airborne contaminants (>450 substances), lead, asbestos, and worker-right-to-know (MSDSs). He has conducted numerous occupational health surveys and has extensive experience in the sampling and analysis of indoor air quality at residences, workplaces, and school classrooms.

Examples

Preliminary Report on Indoor Air Quality in Elementary School Portable Classrooms, Marin County, Ca. (December 1999)

Health Risk Assessment Due to Diesel Train Engine Emissions, Oakland, Ca. (June 1999)

Air Pathway Analysis for the Ballard Canyon Landfill,. Submitted to the County of Santa Barbara, (March 1999)

Review and Evaluation of the Health Risk Assessment for Outdoor and Indoor Exposures at the Former Golden Eagle Refinery Site, Carson, Ca. (May 1998)

The Avila Beach Health Study Phase 1: Reconnaissance Sampling Findings, Conclusions, and Recommendations. (July 1997) Volume 1: Baseline Human Health Risk Assessment. (May 1998)
The Avila Beach Health Study Phase 1, Volume 2: Environmental Monitoring. (May 1998)

Phase 2 Human Health Risk Assessment, Teledyne Inc., San Diego, Ca. (February 1997)

Determination of Occupational Lead Exposure at a Tire Shop in Placerville, Ca. (April 1993)

Development of an Environmental Code of Regulations for Hazardous Waste Treatment Facilities on La Posta Indian Tribal lands, San Diego County, Ca. (August 1992)

Sampling and Analysis Plan, Health and Safety Plan, Site Characterization of Lead Oxide Contaminated Areas, Mare Island Naval Shipyard, Vallejo, California. Prepared in conjunction with Kaman Sciences Corp. (September 2, 1988)

Hazardous Materials Assessments, Waste Management Assessments, Worker Safety and Fire Protection Assessments, and Public Health Impacts Assessments

Dr. Greenberg also has significant experience as a consultant and expert witness for the California Energy Commission providing analysis, recommendations, and testimony in the areas of hazardous materials management, process safety management, waste management, worker safety and fire protection, and public health impacts for proposed power plant/cogeneration facilities. These analyses include the evaluation and/or preparation of the following:

- Off-site consequence analyses of the handling, use, storage, and transportation of hazardous materials,
- Risk Management Plans (required by the Cal-ARP) and Business Plans (required by H&S Code section 25503.5),
- Safety Management Plans (required by 8 CCR section 5189),
- Natural gas pipeline safety,
- Solid and hazardous waste management plans,
- Phase I and II Environmental Site Assessments,
- Construction and Operations Worker Safety and Health Programs,
- Fire Prevention Programs,
- Human health risk assessment from stack emissions and from diesel engines, and
- Mitigation measures to address PM exposure, including diesel particulates

Examples

- San Francisco Energy Reliability Project, San Francisco, Ca. 2004-present. Hazardous materials management, worker safety/fire protection, waste management, public health
- Inland Empire Energy Center, Romoland, Ca. 2002-3. hazardous materials, worker safety/fire protection, waste management, public health
- Malburg Generating Station Project, City of Vernon, Ca. 2002-3. hazardous materials, worker safety/fire protection, waste management, public health
- Blythe II, Blythe, Ca. 2002-3. hazardous materials, worker safety/fire protection,
- Palomar Energy Center, Escondido, Ca. 2002-3. hazardous materials, worker safety/fire protection, waste management, public health
- Cosumnes Power Project, Rancho Seco, Ca. 2002-3. hazardous materials, worker safety/fire protection, waste management, public health
- Tesla Power Project, Tesla, Ca. 2002-3. hazardous materials, worker safety/fire protection, waste management, public health
- San Joaquin Valley Energy Center, San Joaquin, Ca. 2002-3. hazardous materials, worker safety/fire protection, waste management
- Morro Bay Power Plant, Morro Bay, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management

- Potrero Power Plant Unit 7, San Francisco, Ca., 2001-2: hazardous materials, worker safety/fire protection
- El Segundo Power Redevelopment Project, El Segundo, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management
- Rio Linda Power Project, Rio Linda, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Pastoria II Energy Facility Expansion, Grapevine, Ca., 2001: hazardous materials, worker safety/fire protection
- East Altamont Energy Center, Byron, Ca., 2001-2: hazardous materials, worker safety/fire protection
- Magnolia Power Project, Burbank, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Russell City Energy Center, Hayward, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management
- Woodbridge Power Plant, Modesto, Ca., 2001: hazardous materials, worker safety/fire protection, waste management
- Colusa Power Plant Project, Colusa County, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Valero Refinery Cogeneration Project, Benicia, Ca., 2001: hazardous materials, worker safety/fire protection
- Ocotillo Energy Project, Palm Springs, Ca., 2001: hazardous materials, worker safety/fire protection
- Gilroy Energy Center Phase II Project, Gilroy, Ca., 2001-2: hazardous materials, worker safety/fire protection
- Los Esteros Critical Energy Facility, San Jose, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Roseville Energy Facility, Roseville, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Spartan Power, San Jose, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Inland Empire Energy Center, Romoland, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- South Star Cogeneration Project, Taft, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Tesla Power Plant, Eastern Alameda County, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Tracy Peaker Project, Tracy, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Henrietta Peaker Project, Kings County, Ca., 2001: hazardous materials, worker safety/fire protection, waste management, public health
- Central Valley Energy Center, San Joaquin, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Cosumnes Power Plant, Rancho Seco, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Los Banos Voltage Support Facility, Western Merced County, Ca., 2001-2: waste management, public health

- Palomar Energy Project, Escondido, Ca., 2001-2: hazardous materials, worker safety/fire protection, waste management, public health
- Metcalf Energy Center, San Jose, Ca., 2000-1: hazardous materials
- Blythe Power Plant, Blythe, Ca., 2000-1: hazardous materials
- San Francisco Energy Co. Cogeneration Project, San Francisco, Ca., 1994-5: hazardous materials
- Campbell Soup Cogeneration Project, Sacramento, Ca., 1994: hazardous materials
- Proctor and Gamble Cogeneration Project, Sacramento, Ca., 1993-4: hazardous materials
- San Diego Gas and Electric South Bay Project, Chula Vista, Ca., 1993: hazardous materials
- SEPCO Project, Rio Linda, Ca., 1993: hazardous materials
- Shell Martinez Manufacturing Complex Cogeneration Project, Martinez, Ca., 1993: hazardous materials and review and evaluation of EIR

DECLARATION OF
Mark R. Hamblin

I, Mark R. Hamblin declare as follows:

I am presently employed by the California Energy Commission in the Environmental Protection Office of the Systems Assessments and Facilities Siting Division as a Planner II.

A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

I prepared the Visual Resources section in the Final Staff Assessment for the Blythe Energy Project Phase II (BEP II) based on my independent analysis and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: April 6, 2005 Signed: Mark R. Hamblin

At: Sacramento, California

MARK R. HAMBLIN

Summary

Public administrator/land use planner with 15 years experience addressing land use development matters of concern to citizens and government leaders. Expertise in interpreting public policy pertaining to land use and environmental assessment. Demonstrated ability in working with individuals, and on teams involved in the development permitting process.

Professional Experience

California Energy Commission, Sacramento, CA.
Planner II November 2000 to present.

Prepares an independent technical analysis in the area(s) of land use, traffic & transportation, and visual resources to inform interested persons and to make recommendations to the Energy Commission regarding the consequences of a natural gas fired power generation plant proposal; reviews information provided by the applicant and other sources to assess the environmental effects of a proposal as required by the California Environmental Quality Act (CEQA), and the California Energy Commission siting regulations; evaluates project in accordance with federal, state and local laws, ordinances, regulations, standards (LORS); coordinates proposal with federal, state and local agencies; conducts field studies; oversees technical consultant(s); participates in public workshop(s) on proposal; presents sworn testimony during evidentiary hearings; implements compliance monitoring programs for projects approved by the Energy Commission to ensure that power plants are constructed and operated according to the conditions of certification of their license.

Yolo County Planning and Public Works Department, Woodland, CA.
Associate Planner June 1992 to October 2000.

Advised and assisted individuals in the processing of land use requests (general plan amendments, conditional use permits, subdivision maps, etc.); reviewed information provided by the applicant and other sources for consistency with the state zoning and planning law, the county General Plan, the county government code, and the requirements of the CEQA; collected and analyzed information pertaining to a land use request and presented it in a staff report for consideration by the county planning commission and/or county board of supervisors; board of supervisors liaison, and planning department staff person to citizen and inter-agency committees (county airport advisory committee, county habitat conservation plan steering committee, and community general plan citizen advisory committee(s); drafted zoning ordinances and regulations; prepared environmental assessment documents in accordance with CEQA and NEPA (National Environmental Protection Act); hired and supervised consultants; executed county zoning administrator duties; conducted zone code enforcement; reviewed building plans for issuance of permits; answered questions at the public counter, or on the telephone regarding land use issues and development proposals in the County.

Yolo County Community Development Agency, Woodland, CA.
Assistant Planner January 1991 to June 1992.

Advised and assisted individuals in the processing of land use requests; reviewed information provided by the applicant and other sources for consistency with the county General Plan, the state and county government code, and the requirements of CEQA; collected and analyzed information pertaining to a land use request and presented it in a staff report for consideration by the county planning commission; drafted zoning ordinances; prepared environmental assessment documents in accordance to the CEQA; supervised consultants; conducted zone code enforcement; reviewed building plans for issuance of permits; answered questions at the public counter, or on the telephone regarding land use and development in the County.

Tulare County Planning and Development Department, Visalia, CA.
Planning Technician II March 1988 to January 1990.

Advised and assisted individuals in the processing of land use requests, specifically special-use permits, variances, parcel and subdivision maps; reviewed information provided by the applicant and other sources for consistency with the county General Plan, the state and county government code, and the requirements of CEQA; collected and evaluated information for presentation in a staff report on the proposed land use request for consideration by the county zoning administrator, site plan review committee, or planning commission; prepared environmental assessment documents in accordance with CEQA; conducted zone code enforcement; reviewed building plans for issuance of permits; answered questions at the public counter, or on the telephone regarding land use and development in the County.

Education

University of California, Davis Extension. Coursework in California Land Use Planning and the California Environmental Quality Act 1988 to 1995.
Cosumnes River College. Coursework in Television and Radio Broadcasting1990 to 1991.
California State University, Bakersfield. Master of Public Administration; August 1988. Concentration in Public Policy. Coursework in Business Administration and Political Science.
California State University, Sacramento. Bachelor of Science in Public Administration; May 1984. Concentration in Human Resources Management.
Porterville College. Associate in Arts Social Science; May 1982. Coursework in Administration of Justice.

Awards

2001 Superior Accomplishment Award - Recognition of outstanding performance and contribution as a Team Member of the "21 Day, 4, 6, and 12 Month Processes Team." California Energy Commission.

2001 Superior Accomplishment Award - Recognition of outstanding performance and contribution as a Team Member of the "Expedited 4 Month AFC/SPPE Team," California Energy Commission.

DECLARATION OF
Susan V. Lee

I, **Susan V. Lee** declare as follows:

1. I am presently employed by **ASPEN ENVIRONMENTAL GROUP**, a contractor to the California Energy Commission, Systems Assessments and Facilities Siting Division as a **Vice President**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **ALTERNATIVES SECTION**, for the **BLYTHE ENERGY PROJECT PHASE II** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: April 5, 2005 Signed: Susan V Lee

At: San Francisco, California

SUSAN V. LEE
Vice President, San Francisco Operations

ACADEMIC BACKGROUND
M.S., Applied Earth Science, Stanford University, 1984
B.A., Geology, Oberlin College, 1977

PROFESSIONAL EXPERIENCE

Ms. Lee has over 20 years of technical and managerial experience in environmental assessment, and she currently manages Aspen's San Francisco Office. Her expertise is in management of environmental assessment for energy projects (pipelines, transmission lines, and electric power plants) under both the California Environmental Quality Act (CEQA) and the National Environmental Policy Act (NEPA). Prior to employment at Aspen, Ms. Lee worked for 10 years with the Federal government [the U.S. Minerals Management Service (MMS) and the U.S. Geological Survey (USGS)]. As a geologist and team leader at the USGS and MMS, she worked extensively with land use planning issues and offshore oil and gas exploration and development, including planning, regulatory enforcement, and environmental review.

Aspen Environmental Group — 1993 to present

Ms. Lee has contributed to both technical and project management aspects of Aspen's environmental projects, including the following:

- **Jefferson-Martin 230 kV Transmission Line Project**. Ms. Lee managed preparation of an EIR for PG&E's proposed 27-mile transmission line through scenic San Mateo County in the Highway 280 corridor, urban Colma and Daly City, and across San Bruno Mountain for the California Public Utilities Commission (CPUC). This controversial and high profile project is considered to be an essential component of San Francisco's energy supply, and involved coordination with numerous local and regional jurisdictions. The Final EIR for this project was awarded the first place in the Outstanding Environmental Analysis Document competition by the Association of Environmental Professionals (April 2004). Major components of this project include the following:
  - The Draft EIR was published in July 2003, and over 800 pages of comments were submitted. The 2,600 page, three-volume Final EIR included responses to all comments and was published in November 2003.
  - A Supplemental Alternatives analysis was prepared in June of 2004 in response to the Assigned Commissioner's Ruling, requiring analysis of two additional alternatives.
  - Ms. Lee managed a team of Aspen staff specialists supplemented by experts with 8 subcontractor firms. Key issues were geology (the route closely follows the San Andreas Fault), transmission design and regional transmission planning, visual resources and recreation, and biological resources.
  - The EIR included a 200-page Alternatives Screening Report (as an EIR Appendix), which evaluated 38 alternatives including numerous route alternatives, potential new generation and renewable energy options, and other "non-wires" alternatives to transmission lines.
  - A comprehensive public and agency scoping period was held, including 4 public meetings and 10 meetings with affected public agencies to discuss specific concerns and recommendations. A detailed Scoping Report was prepared and made available on the project website.
  - The Public Involvement Program for the project included development and maintenance of a nearly 10,000 person mailing list, a project website that was updated at each phase of the project, two informal workshops

to inform the public about the Draft EIR and its contents/conclusions, and a total of 6 formal Public Participation Hearings on the Draft and Final EIR.

- After release of the Final EIR, Ms. Lee provided support to the CPUC and the Administrative Law Judge and the Assigned Commissioner during preparation of the Draft Decision and to provide additional alternatives analysis.

- **U.S. Department of Agriculture Forest Service, Region 5 On-Call Environmental Services.** Ms. Lee is the Program Manager for Aspen's three-year contract with the Forest Service to provide NEPA compliance and environmental services to National Forests throughout California. The contract began in early 2004. Projects awarded to date have included biological/cultural surveys and NEPA documentation for fuels management programs at the Angeles National Forest (San Bernardino and Los Angeles Counties), and soil surveys in the Mendocino National Forest.

- **PG&E Los Banos–Gates 500 kV Transmission Project**. Ms. Lee managed preparation of a Supplemental EIR for the California Public Utilities Commission (CPUC) to evaluate potential impacts of an 84-mile transmission line in the San Joaquin Valley. This line is considered critical to enhancing electric reliability in the State, and will relieve transmission congestion between southern and northern California. Aspen's team included 8 subcontractors. The Draft SEIR was released in October 2001 and the Final SEIR was published in February 2002. The project was ultimately not approved by the CPUC because it was constructed under approval by the Western Area Power Administration.

- **PG&E Northeast San Jose Transmission Reinforcement Project**: Ms. Lee served as the Project Manager for this CPUC contract to evaluate PG&E's proposed transmission improvements in Santa Clara and Alameda Counties. The project included a 7-mile 230kV transmission line, a new substation, and connections to several 115kV distribution lines. A major environmental issue was biological resources (the proposed transmission line route would have passed through the San Francisco Bay National Wildlife Refuge and the habitat of several endangered species) and potential effects on high-tech business parks along the transmission line route (in the heart of "Silicon Valley"). Numerous alternative transmission line routes were identified and evaluated in the Draft EIR, Supplemental Draft EIR, and Final EIR. The Final EIR, including a recommended 3.5 mile underground 230 kV transmission line segment, was certified by the CPUC in April 2001. Ms. Lee also managed the mitigation monitoring program for this contract, which was completed when construction finished in mid-2003.

- **California Energy Commission**. Ms. Lee has supported CEC staff since the fall of 2000. To date, she has prepared analyses for 12 power plants throughout the State, and she has also contributed to several special project reports. She has participated in numerous public workshops and hearings around the state, and completed the CEC's Expert Witness Training. Her major efforts for the CEC include the following:

  - Ms. Lee prepared a detailed Background Report and made a presentation at an Energy Commission workshop on **"Comparative Alternatives to Transmission"** as part of the Integrated Energy Policy Report (IEPR) 2004 Update process. This project evaluated non-wires alternatives to transmission lines; ongoing work is related to development of a methodology for consideration of these alternatives as part of the transmission planning process.

  - Ms. Lee has prepared **Alternatives Analyses** (consistent with CEQA and the CEC's procedures) for the CEC's staff reports considering proposed new or repowered power plants at Blythe (BEPII), Morro Bay, El Segundo, Avenal, San Joaquin Valley, Potrero (San Francisco), Tracy, East Altamont, and Henrietta. She is currently preparing a comprehensive alternatives analysis for the San Francisco Electric Reliability Project.

- Ms. Lee has managed preparation of **Power Plant Cooling Options Reports** for the Potrero Unit 7 Project, Morro Bay, SMUD Cosumnes, and El Segundo power plants. These analyses include conceptual design of dry cooling systems, hybrid cooling systems, and water supply options including use of reclaimed water in both once through and hybrid cooling systems.
- Ms. Lee has provided management and technical support to Aspen's preparation of several reports for the CEC: the Environmental Performance Report, the Coastal Power Plant Study, and the Alternative Generation Technology study.
- Ms. Lee served as the CEC's **Project Manager** for the Small Power Plant Exemption (SPPE) environmental review process for the Woodland Generation Station 2, an 80-megawatt power plant proposed by the Modesto Irrigation District. In this role, she managed preparation of a Draft and Final Initial Study (including mitigation measures, or "conditions of exemption"), held workshops to hear Applicant and public comments, coordinated extensively with CEC staff counsel, and represented the CEC at the Evidentiary Hearing for the project which was approved by the CEC in 2002 and was constructed during 2003.

- **PG&E Region On-Call Environmental Services Contract.** Ms. Lee served as Aspen's Program Manager for this multi-year contract with the CPUC (1999 - 2005) to provide CEQA analysis and mitigation monitoring services for projects in northern California. In addition to the Tri-Valley Project (described separately), projects completed or underway under this contract include:
  - PG&E Substations Mitigation Monitoring (Santa Clara County Nortech Substation and others) and development of general monitoring procedures.
  - Preparation of an Initial Study and Mitigated Negative Declaration (MND) for the Atlantic-Del Mar (70 kV) Reinforcement Project. The project was approved by the CPUC in 2002 and construction is expected to begin in late 2004, with Aspen monitors ensuring compliance with all adopted mitigation measures.
  - For the Paradise Power Line (115 kV) Project, Aspen prepared a MND and performed mitigation monitoring during construction, which is now complete.
  - Aspen performed mitigation monitoring for PG&E's installation of portions of natural gas pipeline Line 401 in Shasta and Modoc Counties, under an EIS/EIR completed by the CPUC in the early 1990's.

- **PG&E Tri-Valley 2002 Capacity Increase Project.** Ms. Lee managed preparation of the Draft and Final EIRs for this controversial and complex project during 2000 and 2001, which was certified by the CPUC in May 2001. The Draft EIR (over 800 pages) evaluated proposed transmission lines and substations in the Tri-Valley area (Cities of Pleasanton, Dublin, Livermore, and San Ramon) of Alameda and Contra Costa Counties, and responded to a high level of local concern regarding electric and magnetic fields (EMFs). The EIR presented a range of route and electrical system alternatives for the transmission line segments proposed by PG&E. Ms. Lee developed the project description and managed the alternatives screening and analysis process, and also supervised a team of 11 subcontractors. The Final EIR was certified in November 2001 and construction began in mid-2002. Ms. Lee is also managing the mitigation monitoring phase of the project; the first two phases of a three-phase construction process were completed in November 2003. Phase 3 construction, also to be managed by Aspen, will begin in late 2004 and continue for about 18 months.

- **On-Call Environmental Services Contract for 50-200kV Transmission Lines and Substations (SCE Region).** Under this three-year contract (starting in 1999), Ms. Lee provided CEQA support to CPUC staff for the Lucerne Valley to Big Bear Transmission Line EIS/EIR (San Bernardino County). Her responsibilities included technical review of the Administrative Draft EIS/EIR, detailed review and re-writes of mitigation measures, evaluation of alternatives to determine the CEQA Environmentally Superior Alternative, and attendance at numerous meetings with the CPUC, U.S. Forest Service, and the Edison EIS/EIR contractor.

- **Deputy Program Manager and Delivery Order Manager, U.S. Army Corps of Engineers General Environmental Services Contracts.** For Aspen's on-call environmental services contracts with the

Los Angeles District, Army Corps of Engineers, Ms. Lee has managed several projects requiring NEPA compliance in southern California and Arizona. She has managed preparation of Environmental Assessments for federal agencies, local flood control and recreation districts and military facilities. Projects have included a mitigation measure implementation plan for the U.S. Army's Fort Irwin National Training Center and a variety of environmental assessments related to flood control projects and biological resources in southern California. Other examples of projects she managed are:

- **Lower Colorado River Capacity and Boundary Preservation Project**: Ms. Lee is managing preparation of an Environmental Impact Statement (EIS) for this project. The project is intended to increase the floodflow capacity of the Colorado River and to permanently define the international border between the U.S. and Mexico, in compliance with international agreements and treaties. Several alternatives are being evaluated, including various locations and designs for a pilot channel. The major issues for the project relate to potential project effects on endangered birds in the riparian habitat in the river channel and potential conflicts with Cocopah Indian Tribe land. The project has required extensive and ongoing coordination with a large number of agencies (U.S. Fish & Wildlife Service, U.S. Bureau of Reclamation, U.S. International Boundary and Water Commission, Arizona Department of Game and Fish, Bureau of Indian Affairs). A baseline environmental report was prepared by Aspen in 1999 and is being updated in key issue areas. A series of Stakeholder Meetings were held in Yuma, at which Ms. Lee presented updates on the EIS process.
- **Imperial Beach Shoreline Protection EIS/EIR**. Ms. Lee managed preparation of the environmental baseline section of this EIS/EIR, including marine biological analysis of sensitive kelp beds and sand sources for beach replenishment.
- **Lower Santa Ana River Operations and Maintenance Environmental Assessment.** Ms. Lee managed preparation of this project that evaluated the impacts of a range of river maintenance plans, including dredging in the lower reach, clearing of trees and shrubs, and regular sediment removal from hard bottom areas.
- **Project Mitigation Plan for Land Acquisition EIS, U.S. Army Fort Irwin National Training Center (San Bernardino County):** Ms. Lee managed preparation of this plan that defined how each mitigation measure would be implemented and how its implementation would be ensured.

- **Kinder Morgan Concord-Sacramento Pipeline**. Ms. Lee managed preparation of an EIR for the California State Lands Commission evaluating a proposed 70-mile petroleum products pipeline through Contra Costa, Solano, and Yolo Counties. Major issues related to pipeline safety and the protection of Sacramento/San Joaquin Delta waterways and surrounding biological resources. Ms. Lee managed Aspen's in-house technical and management staff, as well as 7 subcontractor firms. The Final EIR was published in September 2003 and certified by the CSLC in November 2003.

- **Telecommunications On-Call Contract**. Ms. Lee is the Program Manager for an on-call contract awarded to Aspen in 2002 by the CPUC to evaluate telecommunications projects throughout California and to provide mitigation monitoring services. Projects under this contract to date include the following:

  - **Looking Glass Networks**: This proposed network involves construction in the San Francisco Bay Area and the Los Angeles Basin to allow fiber optic connections in numerous locations. Aspen prepared an Initial Study/Mitigated Negative Declaration (IS/MND) in November 2002 and distributed both paper and CD-ROM copies to appropriate jurisdictions for review and comment. Construction of small segments began in 2003, with Aspen serving as mitigation monitoring contractor for the CPUC.
  - **Williams Communications Sentry Marysville Project**: This small project would allow the Applicant to provide fiber optic connection to an air force base in Yuba County. Aspen prepared an IS/MND in December 2002 for publication in January 2003, and monitored construction which was completed in mid-2003.
  - **Metromedia Fiber Network Services**: This project involves monitoring services only, pursuant to a MND completed earlier by the CPUC.

- **PG&E Hydrodivestiture Project.** The 11-volume Draft EIR prepared for the CPUC to consider PG&E's proposed divestiture of its hydroelectric assets was prepared in Aspen's San Francisco office. Ms. Lee assisted in project and contract management, technical review, and document production.

- **Pacific Pipeline Project EIS/Subsequent EIR.** This 2,500-page document (completed in 1996) evaluated a proposed crude oil pipeline from Kern County to refineries in Los Angeles and El Segundo. Ms. Lee performed the duties of Deputy Project Manager and Issue Area Coordinator for Earth Sciences and Cultural Resources, including coordination with Pacific Pipeline System, Inc. (PPSI, the project proponent), assistance in managing of a team of technical subcontractors, and document preparation and production coordination. She participated in alternatives screening analyses, alternatives comparison, and ensured that the document was consistent with applicable requirements of CEQA and NEPA. She also served as the Issue Area Coordinator for Geology, Soils, Hydrology, and Environmental Contamination issue areas and represented the Lead Agencies in public workshops.

- **Pacific Pipeline Mitigation Monitoring, Compliance, and Reporting Program.** Ms. Lee served as Deputy Program Manager for the pre-construction phase of this monitoring and compliance project for construction of a 132-mile crude oil pipeline in southern California, under contract to the California Public Utilities Commission and the Angeles National Forest. Her primary responsibilities included management of technical plan review for the approximately 100 plans and reports required prior to construction; management of subcontractors providing technical expertise; and coordination with lead agencies and pipeline owner/contractors.

- **Alturas Transmission Line EIR/S.** For this project evaluating a 345 kV transmission line in northeastern California and Nevada, Ms. Lee served as Issue Area Coordinator, providing management support and technical oversight of geology and hydrology issue areas. She also drafted project description, provided technical review, and managed subcontractor labor for this 165-mile proposed linear project. She managed preparation of master Mitigation Monitoring Program and the Impact Summary Tables for the Final EIS/R.

- **Kinder Morgan Carson-Norwalk Pipeline EIR and Mitigation Monitoring, Compliance, Reporting, and Program (MMCRP).** As Project Manager, Ms. Lee managed the CEQA evaluation of a proposed 13-mile petroleum products pipeline in urban Los Angeles for the CPUC. The project included review of Kinder Morgan's Proponent's Environmental Assessment (PEA), preparation of an Initial Study, and a Draft and Final EIR. The Final EIR was completed in May 1998 (certified in October 1998). Public participation activities included Scoping Meetings, an Informational Workshop, a Public Participation Hearing, a project newsletter, and creation of an Internet website. Alternatives to five portions of the proposed pipeline route were identified. Sensitive issues included pipeline safety, potential impacts on water wells and surface waters, and construction impacts such as noise and air quality degradation. Ms. Lee also managed the MMCRP for the construction of the Carson-Norwalk Pipeline.

- **Yellowstone Pipeline Reroute EIS.** Aspen prepared an EIS for the USDA Forest Service, Lolo National Forest, for a controversial petroleum products pipeline in western Montana. Ms. Lee served as Issue Area Coordinator for three issue areas: Hydrology and Water Resources; Geology, Mineral Resources, and Paleontology; and Soils. Her responsibilities included coordination of management issues with project scientists and agency personnel, review of technical reports, oversight of fieldwork, and writing of EIS text from technical reports prepared by issue area specialists.

Previous Employment **1977 to 1993**

Ms. Lee worked for seven years with the U.S. Minerals Management Service (MMS), Pacific OCS Region. As a geologist and team leader in the MMS Field Operations office from 1979 to 1987 (during the Region's most active period of oil and gas exploration and development), she reviewed numerous

offshore oil and gas exploration and development plans. Her responsibilities at MMS also included regulatory enforcement and facility inspection, coordination of environmental and technical review of development proposals, and participation in the EIS and Coastal Commission Consistency Review processes with inter-agency Joint Review Panels. Ms. Lee maintains an excellent working relationship with MMS's Pacific OCS Region staff.

- At MMS, Ms. Lee specialized in regulatory enforcement and review of offshore oil and gas platforms, especially application of regulations regarding air quality and oil and gas production, and supervised other geologists and engineers.
- During three years (1977 to 1979) with the U.S. Geological Survey (USGS) in Reston, Virginia, in the Earth Sciences Applications Program, Ms. Lee participated in development of geologic hazards information in formats accessible to land use planners and non-scientific personnel.

From 1987 through 1992, Ms. Lee worked as an independent consultant and corporate Marketing Director. In these positions she developed and managed the marketing program for Pasadena's leading real estate brokerage, and she also created and promoted her own successful real estate firm.

SELECTED TECHNICAL REPORTS

Analysis of Competitive Bidding in Offshore California Lease Sales (Masters Report, Stanford University, 1984)

Article on Subsidence and Land Use Planning Issues, *in* U.S. Geological Professional Paper entitled "Nature to be Commanded ..."

Landslide Risk in the United States, U.S. Geological Survey Map MF-771 (contributing researcher).

CERTIFICATES/AWARDS

- Association of Environmental Professionals – First Place Award for Outstanding Environmental Analysis Document (2004): Jefferson-Martin 230 kV Transmission Line EIR
- California Energy Commission's Outstanding Performance Award for 2001

TRAINING

California Energy Commission Expert Witness Training

DECLARATION OF
Al McCuen, Shahab Khoshmashrab and Steve Baker

We the undersigned, declare as follows:

1. We are presently employed by the California Energy Commission in the **Engineering Office** of the Systems Assessment and Facility Siting Division as

   Senior Electrical Engineer-Mr. McCuen, Mechanical Engineer-Mr. Khoshmashrab and **Senior Mechanical Engineer-Mr. Baker.**

2. Copies of our professional qualifications and experience are attached hereto and incorporated by reference herein.

3. We prepared our respective portions of the Staff Testimony on **Facility Design**, for the **Blythe Energy Project Phase 2** based on our independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and our professional experience and knowledge.

4. It is our professional opinion that the prepared Testimony is valid and accurate with respect to the issues addressed therein.

5. We are personally familiar with the facts and conclusions related in the testimony and if called as witness(es) could testify competently thereto.

We declare under penalty of perjury that the foregoing is true and correct to the best of our knowledge and belief.

Al McCuen _____

Shahab Khoshmashrab _____

Steve Baker _____

Dated: March 23, 2005

At: Sacramento, California

Albert A. McCuen
SENIOR ELECTRICAL ENGINEER

Education

A.S., Electronic Engineering, College of the Siskiyous, Weed, CA
B.S., Electrical Engineering, California State University, CA

Professional Background

1990 to present--Senior Transmission Planner for Regulatory Transmission Engineering, Electrical Engineering, and Transmission System Evaluation. Special consultant for Transmission Safety and Nuisance discipline.

1987 to 1989--Supervisor of Transmission Evaluation Unit for Transmission Safety and Nuisance, Electrical Engineering, Transmission Engineering and Transmission System Evaluation technical disciplines.

1978 to 1987--Transmission System Program Specialist/Health and Safety Program Specialist, California Energy Commission (CEC), Siting and Environmental Division.

Expert witness for the Commission's power plant approval process and Commission staff transmission planner. Major assignments in transmission engineering and transmission system planning. Duties emphasize determination of the adequacy, acceptability and relative merit of applicant proposals for major transmission facilities (and staff proposed alternatives) in consideration of economics, reliability, conformance with transmission system planning criteria and coordination of regional transmission and generation facilities. Major assignments have also included scoping macro transmission policies for California, Developing Commission transmission system planning regulations and guidelines, developing common forecasting methodology for transmission system planning utility reporting.

1977 – 1978--Manager, Transmission Line Effects Section, CEC, Compliance and Safety Office.

Research, analysis and evaluation of public heath, safety and nuisance concerns for transmission lines. Duties included engineering calculations of transmission line electrical effects, review and assessment of technical publications and health, safety and nuisance standards.

1976 – 1977--Energy Facility Siting Planner, CEC, Compliance and Safety Office

Research and evaluation of existing material and health and safety standards applicable to thermal power plants and transmission lines. Responsible for coordination of expert witness to testify at hearings, preparation of cross examination questions, analysis of impact of effects and preparation of staff summary reports on Notice of Intent(s) and hearing testimony.

1969 – 1976--Electrical Engineering, Private firm - Electrical, Mechanical and Systems Engineering Construction Contractor. Engineering duties and coordination responsibilities for the construction of power plants, switchyards, power lines, industrial buildings and process control systems. Responsible for code and specification interpretation and compliance, design, project cost estimates and installation.

Shahab Khoshmashrab
Mechanical Engineer

Experience Summary

Nine years experience in the Mechanical, Civil, Structural, and Manufacturing Engineering fields involving engineering and manufacturing of various mechanical components and building structures. This experience includes QA/QC, construction/licensing of electric generating power plants, analysis of noise pollution, and engineering and policy analysis of thermal power plant regulatory issues.

Education

- California State University, Sacramento-- Bachelor of Science, Mechanical Engineering
- Registered Professional Engineer (Mechanical), California

Professional Experience

2001-2004--Mechanical Engineer, Systems Assessment and Facilities Siting– California Energy Commission

Performed analysis of generating capacity, reliability, efficiency, noise and vibration, and the mechanical, civil/structural and geotechnical engineering aspects of power plant siting cases.

1998-2001--Structural Engineer – Rankin & Rankin

Engineered concrete foundations, structural steel and sheet metal of various building structures including energy related structures such as fuel islands. Performed energy analysis/calculations of such structures and produced structural engineering detail drawings.

1995-1998--Manufacturing Engineer – Carpenter Advanced Technologies

Managed manufacturing projects of various mechanical components used in high tech medical and engineering equipment. Directed fabrication and inspection of first articles. Wrote and implemented QA/QC procedures and occupational safety procedures. Conducted developmental research of the most advanced manufacturing machines and processes including writing of formal reports. Developed project cost analysis. Developed/improved manufacturing processes.

STEVE BAKER, P.E.
Senior Mechanical Engineer

Experience Summary

Thirty years experience in the electric power generation field, including mechanical design, QA/QC, construction/startup and business development/licensing of nuclear, coal-fired, hydroelectric, geothermal and windpower plants; and engineering and policy analysis of thermal power plant regulatory issues.

Education

- California State University, Long Beach--Master of Business Administration
- California State Polytechnic University, Pomona--Bachelor of Science, Mechanical Engineering
- Registered Professional Engineer (Mechanical), California — No. M27737 expires 6/30/06

Professional Experience

1990 to Present--Senior Mechanical Engineer, Siting & Environmental Division - California Energy Commission

Technical lead person for the analysis of generating capacity, reliability, efficiency, noise, and the mechanical, civil/structural and geotechnical engineering aspects of power plant siting cases. Key contributor to Commission's investigation into market impediments to the deployment of advanced high-efficiency generating technologies.

1987 to 1990--Generation Systems/Facility Design Unit Supervisor, Siting & Environmental Division - California Energy Commission

Responsible for supervising the analysis of generating capacity, reliability, efficiency, safety, and mechanical, civil/structural, and geotechnical engineering aspects of power plant siting cases.

1981-1986--Operations Manager, Alternate Energy - Santa Fe Pacific Realty Corporation

Participated in and supervised identification, evaluation and feasibility analysis, licensing and permitting of hydroelectric, geothermal, windpower and biomass power projects.

1974-1981--Mechanical Engineer, Quality Engineer - Bechtel Power Corporation and Bechtel National, Inc.

Wrote equipment specifications, drew flow diagrams and P&ID's, performed system design and safety analysis for nuclear power plants and nuclear fuel processing plant. Wrote and implemented QA/QC procedures for nuclear power plant. Participated in construction/startup of large coal-fired power plant.

DECLARATION OF
STEVE MUNRO

I, Steve Munro, declare as follows:

1. I am presently employed by the California Energy Resources Conservation and Development Commission in the Environmental Protection Office of the Energy Facilities Siting and Environmental Protection Division as a Compliance Project Manager (Classification: Planner II - Energy Facility Siting).

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the and Compliance Monitoring and Closure Plan section for the Blythe Energy Project based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3/31/05

Signed: Stephen D. Munro

At: Sacramento, California

STEVE MUNRO
Compliance Project Manager

EXPERIENCE SUMMARY

In my current position, I work as a project manager directing technical staff in tasks related to power plant project design, construction, operation, and associated environmental issues. These activities have included negotiating agreements between power plant operators, public agencies, and community groups and working with engineering and technical staff in identifying and resolving technical issues. Prior to working at the Energy Commission, I worked as a project manager and consultant in several other state agencies.

EXPERIENCE RECORD

July 1991 to present, California Energy Commission

Review and process compliance submittals to assure continued compliance of projects with the conditions of the Commission Decision.

Plan, organize, direct and schedule compliance-related activities of staff.

Plan, organize, direct and schedule the work of staff on petitions to amend the conditions of certification contained in Commission power plant decisions.

Prepare letters, memos and reports concerning amendments, and compliance issues and administration.

Organize and conduct workshops and meetings among the staff and between the staff, project licensees, other governmental agencies and members of the public to resolve and discuss issues, procedures, complaints and petitions for amendment involving compliance-related matters.

Assist technical staff in the drafting of compliance conditions to ensure that they are clearly written, effective, and verifiable.

Identify strategic, technical, and policy issues associated with amendments and compliance projects and make policy recommendations.

Arrange, organize, and conduct meetings, audits and on-site inspections to assure continued compliance with Commission requirements.

EDUCATION

B.A. - Degree, University of the Pacific, 1971. Academic Major: Economics. Post-graduate courses at UC Davis.

DECLARATION OF
NATASHA NELSON

I, **NATASHA NELSON** declare as follows:

1. I am presently employed by the California Energy Commission in the **WATER AND WASTE MANEMENT UNIT** of the Systems Assessment and Facilities Siting Division as a **SUPERVISOR**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **SOIL AND WATER RESOURCES**, for the **BLYTHE ENERGY PROJECT PHASE II (02-AFC-1)** based on my independent analysis of reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 4/28/05 Signed: Natasha Nelson

At: Sacramento, California

DECLARATION OF
NATASHA NELSON

I, **NATASHA NELSON** declare as follows:

1. I am presently employed by the California Energy Commission in the **BIOLOGICAL RESOURCES UNIT** of the Systems Assessment and Facilities Siting Division as a **BIOLOGIST**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **BIOLOGICAL RESOURCES**, for the **BLYTHE ENERGY PROJECT PHASE II (02-AFC-1)** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3/10/05 Signed: [illegible]

At: Sacramento, California

NATASHA NELSON
Planner III

Under contract to the U.S. Army Corps of Engineers, I evaluated water quality and riparian restoration designs. Under contract to the U.S. Forest Service, I was the lead editor of Technical Reports relating to aquatic biology, terrestrial biology, soil erosion, and project description. I am professionally trained in wetland restoration and riparian design.

PROFESSIONAL EXPERIENCE

2001 – 2005 SUPERVISOR, California Energy Commission. I supervise the Water and Waste Management Unit in the Environmental Office. I aid in the review of water use in power plants throughout the state.

2001 – 2005 BIOLOGIST, California Energy Commission. I provided independent biological resource assessments of proposed energy plants and related facilities and reviewed the implementation of biological resource conditions of certification required by the Warren-Alquist Act and the California Environmental Quality Act (CEQA). Once energy facilities were constructed and operating, I was responsible for making sure each facility operated in compliance with associated biological resources conditions of certification. These conditions of certification involved endangered species protection, habitat restoration and monitoring, off-site habitat compensation, and wildlife surveys. Agency permit coordination was an important component of my work..

1997 - 2001 BIOLOGIST, Aspen Environmental Group. I was the project manager or technical writer for many projects that involved National Environmental Policy Act (NEPA) and CEQA documentation. The majority of projects were for utility infrastructure (e.g., power plants, transmission lines, petroleum pipelines) and included aspects of Section 404 Clean Water Act permitting and state or federal Endangered Species Act compliance. I performed reconnaissance level wildlife and plant surveys, and researched issues of concern. I also created adaptive management plans for wildlife and habitat restoration in desert and riparian areas.

1996 - 1997 BIOLOGIST, Bureau of Land Management. As the wildlife biologist for the West Mojave Coordinated Planning effort I gathered and synthesized data regarding the state- and federally-listed species in the Mojave desert. I updated and verified all mapping information used in the planning effort including species' range and occurrence data. Most mapping was done using ARC-INFO's AML language and the California Department of Fish and Game database programs (Rarefind and NDDB). During public meetings I gave overviews and presentations of my work to date.

EDUCATION

- B. S. **BIOLOGY**, 1993, Willamette University, Salem, Oregon
- M. S. **WILDLIFE SCIENCE**, 1996, Oregon State University, Corvallis, Oregon

PROFESSIONAL AFFILIATIONS

- Conservation Biology
- Society for Ecological Restoration

DECLARATION OF

Dr. Obed Odoemelam

I, Obed Odoemelam declare as follows:

I am presently employed by the California Energy Commission in the **Environmental Protection Office** of the Systems Assessments and Facilities Siting Division as a **Staff Toxicologist**.

A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

I helped prepare the staff testimony on **Transmission Line Safety and Nuisance** for the **Blythe Energy Project Phase II** based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3/25/05 Signed: Odoemelam

At: Sacramento, California

RESUME

DR. OBED ODOEMELAM

EDUCATION:

1979-1981 University of California, Davis, California. Ph.D., Ecotoxicology

1976-1978 University of Wisconsin, Eau Claire, Wisconsin. M.S., Biology.

1972-1976 University of Wisconsin, Eau Claire, Wisconsin. B.S., Biology

EXPERIENCE:

1989
The Present: California Energy Commission. Staff Toxicologist.

Responsible for the technical oversight of staffs from all Divisions in the Commission as well as outside consultants or University researchers who manage or conduct multi-disciplinary research in support of Commission programs. Research is in the following program areas: Energy conservation-related indoor pollution, power plant-related outdoor pollution, power plant-related waste management, alternative fuels-related health effects, waste water treatment, and the health effects of electromagnetic fields. Serve as scientific adviser to Commissioners and Commission staff on issues related to energy conservation. Serve on statewide advisory panels on issues related to multiple chemical sensitivity, ventilation standards, electromagnetic field regulation, health risk assessment, and outdoor pollution control technology. Testify as an expert witness at Commission hearings and before the California legislature on health issues related to energy development and conservation. Review research proposals and findings for policy implications, interact with federal and state agencies and industry on the establishment of exposure limits for environmental pollutants, and prepare reports for publication.

1985-1989 California Energy Commission.

Responsible for assessing the potential impacts of criteria and noncriteria pollutants and hazardous wastes associated with the construction, operation and decommissioning of specific power plant projects. Testified before the Commission in the power plant certification process, and interacted with federal and state agencies on the establishment of environmental limits for air and water pollutants.

1983-1985 California Department of Food and Agriculture.

Environmental Health Specialist.

Evaluated pesticide registration data regarding the health and environmental effects of agricultural chemicals. Prepared reports for public information in connection with the eradication of specific agricultural pests in California.

DECLARATION OF
Gary Reinoehl

I, Gary Reinoehl declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Office of the System Assessment and Facilities Siting Division as a Planner II.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on Cultural Resources Section, for the Blythe Energy Project Phase II based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: April 5, 2005 Signed: _____

At: Sacramento, California

Gary L. Reinoehl
19387 Ponderosa Drive
Pioneer, CA 95666
(209) 295-5589
email: garreb@volcano.net

Education

School	Field	Degree	Year
Portland State University	Major: Mathematics Minor: Anthropology	Bachelor of Arts	1969
Sonoma State University	Cultural Resources Management	Master of Arts	1998

Experience

State of California, California Energy Commission *1999 to present*
Planner II
Review cultural resources studies submitted to the Commission by energy permit applicants. Write data request in accordance with Commission regulations. Assess eligibility of cultural resources under California Register of Historical Resources criteria. Conduct independent research for impact analysis of proposed energy projects. Write cultural resources section of the Preliminary and Final Staff Assessments (impact assessments), including conditions for the permit to reduce the impacts to cultural resources to less than significant, if possible. Develop mitigation measures to minimize impact to cultural resources. Review and evaluate the work of consultants. Develop standardized documents and processes to enhance the cultural resources process. Work with other staff to draft changes in the Commission regulations. Consult and coordinate with staff from other state and federal agencies. Review and comment on proposed legislation that affect the California Energy Commission process.

State of California, Department of Transportation *1998 to 1999*
Associate Environmental Planner
Conduct background research and prepare environmental documents for a variety of highway projects. Assess environmental impacts in accordance with the California Environmental Quality Act and the National Environmental Policy Act. Request permits from various state and federal agencies. Request record searches, conduct historic property surveys, write historic property survey reports, and coordinate with other agencies. Work with Project Management teams and other specialists to meet project deadlines.

State of California, Department of Parks and Recreation *1982 to 1998*
Associate State Archeologist
Inventory of park properties and State lands from the north coast to the southern desert, including prehistoric sites, historic sites and historic buildings. Excavate prehistoric and historic sites within State Parks for both test purposes and data recovery. Design inventory strategies and excavation strategies for projects on State lands and within State Parks. Provide mitigation measures for projects under the California Environmental Quality Act. Work with historians preparing detailed historic structures reports. Catalogue and analyze archeological collections; write archeological reports; work with maintenance staff, equipment operators, construction crews, managers, rangers, historians, architects, engineers, personnel staff, accounting staff, convict crews, and the general public; supervise seasonal employees and volunteers; work in both state (California Environmental Quality Act) and federal (National Historic Preservation Act) regulatory contexts and provide advice on the Archeological Resource Protection Act, the Native American Graves Protection and Repatriation Act, National Environmental Protection Act, and State Burial Laws; write programmatic agreements and memorandum of agreements under Section 106 of

the National Historic Preservation Act; work with Federal agencies, private contractors, and local agencies; and develop public outreach and educational materials.

Sacramento Archeological Society *1994 to 2004*
Member of Board of Directors
Planned activities of board and society as member of Board. Directed the Board of Directors for two and one half years. Worked with board members to ensure smooth and efficient operation of the Society, including updating the articled of incorporation. Worked with professional archeologists in providing educational and practical experience for the interested public. Assisted in fund raising and public outreach activities for the Society. Coordinated with other interested groups and agencies to enhance the Society's activities. Assisted in developing annual speaker events resulting in public presentations by noteworthy archeologists and anthropologists such as Meave Leakey, Jonathan Kenoyer, James Chatters, and Brian Fagan.

California Institute for Peruvian Studies *1986 to 1987*
Travel Coordinator and archeological crew chief
Advanced planning for field trips to Peru, escorted volunteers while in Lima, Peru, and continuing their trip until arrival in Acari, Peru. Supervised field crews and coordinated recording and detailed mapping of Nazca period structural remains and other sites in Acari Valley.

Additional Experience *1972 to 1982*
Eastern Washington University, U.S. Forest Service (Ochoco National Forest), National Park Service (Petroleum Reserve #4, Alaska; Fort Vancouver National Monument, Vancouver, WA), Archaeological Associates - Northwest, Archaeological Resources Consulting, California State Parks, Oregon Archaeological Society

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Professional Societies
Society for California Archeology

DECLARATION OF
KEVIN ROBINSON

I, Kevin Robinson, declare as follows:

1. I am presently employed by the California Energy Commission in the **ENGINEERING OFFICE** of the Systems Assessment and Facilities Siting Division as a **MECHANICAL ENGINEER**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I co-authored the staff testimony on **POWER PLANT EFFICIENCY** and **POWER PLANT RELIABILITY** for the **BLYTHE ENERGY PROJECT PHASE II** based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3-23-05 Signed: Kevin Robinson

At: Sacramento, California

KEVIN ROBINSON
Mechanical Engineer

Experience Summary

Two years experience in the electric generation field, including mechanical design, QA/QC and construction of hydroelectric plant systems; and engineering and policy analysis of geothermal, natural gas-fired and thermal power plant regulatory issues.

Education

- California State University, Chico—Bachelor of Science, Mechanical Engineering
- Certified EIT, California

Professional Experience

2001 to Present—Mechanical Engineer, Systems Assessment & Facility Siting Division, Engineering Section – California Energy Commission

Responsible for analysis of generating capacity, reliability, efficiency, and the mechanical, civil/structural engineering aspects of power plant siting cases.

2000 to 2001—Mechanical Engineer, Oroville Field Division, Engineering Section – California Department of Water Resources

Assist in the preparation of designs, technical specifications and cost estimates for mechanical equipment at a hydroelectric power plant. Coordinate the design, installation, and inspection of mechanical equipment. Assist in preparing test reports, and recommendations for corrective action.

DECLARATION OF
AMANDA STENNICK

I, **AMANDA STENNICK** declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Protection of the Energy Facilities Siting and Environmental Protection Division as a Planner II.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **SOCIOECONOMICS**, for the **BLYTHE II ENERGY PROJECT** (based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3/23/05 Signed: Amanda Stennick

At: Sacramento, California

AMANDA STENNICK

EDUCATION

B.A. 1986 University of California, Davis, Urban and Economic Geography

WORK EXPERIENCE

Oct. 1993 to April 1998 **Planner I.** California Energy Commission, Energy Facilities Siting and Protection Division.

Provide technical analysis of proposed energy planning, conservation, and development programs on land use and socioeconomic resources. Specific tasks include the analysis of potential impacts, identification of suitable mitigation measures, preparation of testimony, and project monitoring to ensure compliance with local, state and federal environmental laws and regulations. Recent work includes participation in the environmental justice task force, and preparation of environmental justice white paper, presented to Commissioners; research and preparation of discussion on discount rates and net present value for the SFEC siting project; preparation of socioeconomic section on 1996 Quincy Library Group Report; preparation of forestry section on 1997 CEC Global Climate Change Report; ongoing demographic research for environmental justice issues in siting cases.

April 1998 present **Planner II.** California Energy Commission, Energy Facilities Siting and Protection Division.

Provide technical analysis of proposed energy planning, conservation, and development programs on land use and socioeconomic resources. Specific tasks include the analysis of potential impacts, identification of suitable mitigation measures, preparation of testimony, and project monitoring to ensure compliance with local, state and federal environmental laws and regulations. Recent work includes participation in the environmental justice task force, and preparation of environmental justice white paper, presented to Commissioners; research and preparation of discussion on discount rates and net present value for the SFEC siting project; preparation of socioeconomic section on 1996 Quincy Library Group Report; preparation of forestry section on 1997 CEC Global Climate Change Report; ongoing demographic research for environmental justice issues in siting cases.

1992 to 1993 **Environmental Analyst/Planner.** Beak Consultants.

Environmental Planner for EIR/EA for the Mammoth County Water District, involving the analyses of potential impacts resulting from lake water transfers and maintenance of instream flows in the Mammoth Lakes Basin. Prepared land use, socioeconomics, recreation, and public services and utilities sections of EIR/EA.

Environmental Planner for an Effluent Treatment Plant EIR for Simpson Paper company. Prepared land use, socioeconomics, recreation, public services and utilities, cumulative impacts sections, and mitigation monitoring.

Environmental Planner for Folsom/SAFCA Reoperation. Work involved determining parameters of project description with respect to water modeling, project geographic boundaries, and agency jurisdictional boundaries; compliance with federal, state, and local plans and policies.

1990 to 1992 **Environmental Analyst/Project Manager.** ECOS. Inc.

Project Manager/Planner. EIR for a Planned Development, General Plan Amendment, and rezone request for a 504-acre Business and Industrial Park expansion for the Port of Sacramento. Prepared work scope and budget for Public Improvements Plan and a Specific Plan for 80-acre Mixed Use/Water Related development; and Mitigation Monitoring Plan and Statement of Overriding Considerations for the City of West Sacramento. Specific tasks included coordination with subcontractors on technical sections of EIR; meetings with Assistant Port Director and City staff to present Public Improvements Plan, Specific Plan, tentative parcel map, and critical project phasing; discussion with CDFG and Port staff on regional approach to mitigation for project-impacted endangered species.

Project Manager/Planner. EIR for the Wildhorse Residential/Recreational Planned Development for the City of Davis. Specific tasks included CEQA compliance, writing technical sections on land use, project alternatives, and cumulative impacts, and determining appropriate project alternatives as based on traffic models and allowable housing densities.

Project Manager. Yolo County Powerline Ordinance. Project tasks included developing siting policies and mitigation measures for placement of powerlines and substations.

1989 to 1990 **Assistant Planner.** Sacramento County Planning Department.

Principal Author. Energy Component of the Public Services and Facilities Element of the Sacramento County General Plan. Coordinate work efforts with the CEC, SMUD, and PG&E to develop environmental and siting policies for energy facilities and transmission lines; identify environmental impacts and appropriate mitigation measures.

1987 to 1989 **Planner/Assistant Planner.** Yolo County Community Development

Planning liaison for Homestake Mining Company's (HMC) McLaughlin Mine. Conducted meetings on the Technical Review Panel's environmental monitoring of HMC's McLaughlin Mine, and prepared staff reports on the implementation of use permit phasing, regarding issues of water quality, and impacts of the tailings pond on biologic resources. Specific tasks included site visits to monitor the revegetation plan and other mitigation measures as specified in the use permit; oral and written presentations to the Planning Commission.

1988 **Consultant.** Pan Pacific Energy Development Corporation.

Consulting job to develop a regional energy plan for rural areas of developing countries including decentralized non-fossil fuel power plants in agricultural regions. Attended IREC and AWEA International Conference in Honolulu.

PROFESSIONAL AND CONTINUING EDUCATION

1988	California Environmental Quality Act (UC Davis)
1989	Subdivision Map Act (UC Davis)
1991	Fiscal Impact Analysis (UC Davis)
1994	APA Conference (San Francisco)
1994	Environmental Justice Conference (UC Berkeley)
1998	California Environmental Quality Act (California Energy Commission)

PROFESSIONAL AFFILIATIONS

Association of Environmental Professionals
American Planning Association

DECLARATION OF
Ramesh Sundareswaran

I, **Ramesh Sundareswaran** declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Office of the Systems Assessment & Facilities Siting Division as a Health & Safety Program Specialist II.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimonies on Public Health and Waste Management, for the Blythe II project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 3-23-05 Signed: S. R

At: Sacramento, California

RAMESH SUNDARESWARAN

SUMMARY

Offer progressively responsible experience in management, organizational, technical and policy areas related to urban environmental management, pollution control, regulatory compliance and occupational health and safety.

EMPLOYMENT

6/00 -present

Associate(California Energy Commission, Sacramento, CA)
Provided first-line technical advice and input on subjects regarding hazardous materials management, industrial waste management, fire protection and occupational health and safety as part of review of power plant and energy resource licensing. Conducted safety and health assessments to determine risks from hazardous materials and wastes. Prepared and presented expert witness testimonies and recommendations to upper management during licensing regulatory compliance proceedings.

12/97-6/00

Associate(SF Regional Water Quality Control Board, Oakland, CA)
Performed a wide variety of consultative, advisory and evaluative duties in the areas of pollution control due to hazardous chemicals use/release in various industries. Provided expert testimony in formal hearings regarding regulatory compliance of responsible parties. Coordinated with other public agencies and informed and involved the public in addressing environmental risk, mitigation and prevention.

6/92 -12/97

Environmental Engineer(BPS Inc, Torrance, CA)
Developed, planned, coordinated and executed various projects in the areas of environmental mitigation, pollution prevention, regulatory compliance and end-of-pipe treatment for media such as groundwater,

wastewater, soil, air and man-made structures and different pollutants. Prepared workplans, reports, process designs, bids and specifications for such projects. Liaised with governmental agencies and negotiated environmental permits and variances for clients. Advised clients on regulatory interpretations. Testified as fact and expert witness in environmental litigations. Oversight and supervision of staff, subcontractors and vendors in completion of projects. Peer reviewed US Environmental Protection Agency(EPA)'s Industrial Accident Release Prevention Requirements document.

4/90-6/92 *Environmental Engineer (Dames & Moore, Santa Ana, CA)*
Served as technical lead and also provided project team member support for a wide spectrum of environmental projects. Responsibilities included accountability for technical, financial and quality performance. Prepared business proposals and performed new client business development. Was expert panel member on US EPA's treatibility testing guidance document.

8/88-4/90 *Environmental Engineerr (JKB Assoc., Carson, CA)*
Provided management and technical support for various projects ranging from environmental protection to rehabilitation of impaired natural resources. Oversaw subcontractors and vendors in completion of projects. Wrote technical/cost proposals and reports.

6/88-8/88 *Hazardous Waste Specialist (Orange County Health Care Agency, Santa Ana, CA)*
Rendered regulatory oversight for various projects to protect public health and environment. Involved in policy-making and development of environmental regulations.

1/87-6/88 *Instructor (US EPA Air Pollution Training Institute, San Luis Obispo, CA)*

Taught various air pollution courses to both industry and government. Assisted course director in program administration.

OTHER EMPLOYMENT

Marketed corrosion mitigation technologies for over 6 years.

EDUCATION

1987-1988	Master of Engineering, Environmental Engineering, Cal Poly, San Luis Obispo, California
1980-1982	Master of Business Administration, Armstrong University, Berkeley, California
1974-1979	Bachelor of Chemical Engineering, Kaktiya University, India

DECLARATION OF

Rick Tyler

I, Rick Tyler declare as follows:

I am presently employed by the California Energy Commission in the Systems Assessments and Facilities Siting Division as a Senior Mechanical Engineer.

A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

I supervised the preparation of the staff testimony on Hazardous Materials Management and Worker Safety for the Blythe II project Electric Generation Project based on my independent analysis of their application and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 4/5/05 Signed: _____

At: Sacramento, California

RICK TYLER

Associate Mechanical Engineer

CALIFORNIA ENERGY COMMISSION
430 Ashore Ave.
Sacramento, California 95831
(916) 392-1663

EDUCATION B.S., Mechanical Engineering, California State University, Sacramento. Extra course work in Statistics, Instrumentation, Technical Writing, Management; Toxicology, Risk Assessment, Environmental Chemistry, Hazardous Materials Management, Noise Measurement, and regulations regarding control of toxic substances.

Near completion of course work necessary to obtain a certificate in hazardous materials management from University of California, Davis.

EXPERIENCE

Jan. 1998-Present

California Energy Commission - Associate Mechanical Engineer
Energy Facility Siting and Environmental Protection Division

Responsible for review of Applications for Certification (applications for permitting) for large power plants including the review of handling practices associated with the use of hazardous and acutely hazardous materials, loss prevention, safety management practices, design of engineered equipment and safety systems associated with equipment involving hazardous materials use, evaluation of the potential for impacts associated with accidental releases and preparation and presentation of expert witness testimony and conditions of certification. Review of compliance submittals regarding conditions of certifications for hazardous materials handling, including Risk Management Plans Process Safety Management.

April 1985-Jan. 1998

California Energy Commission - Health and Safety
Program Specialist; Energy Facility Siting and Environmental Protection Division.

Responsible for review of Public Health Risk Assessments, air quality, noise, industrial safety, and hazardous materials handling of Environmental Impact Reports on large power generating and waste to energy facilities, evaluation of health effects data related to toxic substances, development of recommendations regarding safe levels of exposure, effectiveness of measures to control criteria and non-criteria pollutants, emission factors, multimedia exposure models. Preparation of testimony providing Staff's position regarding public health, noise, industrial safety, hazardous materials handling, and air quality issues associated with proposed power plants. Advise Commissioners, Management, other Staff and the public regarding issues related to health risk assessment of hazardous materials handling.

Nov. 1977-
April 1985

California Air Resources Board - Engineer (last 4 years Associate level)

Responsible for testing to determine pollution emission levels at major industrial facilities; including planning, supervision of field personnel, report preparation and case development for litigation; evaluate, select and acceptance-test instruments prior to purchase; design of instrumentation systems and oversight of their repair and maintenance; conduct inspections of industrial facilities to determine compliance with applicable pollution control regulations; improved quality assurance measures; selected and programmed a computer system to automate data collection and reduction; developed regulatory procedures and the instrument system necessary to certify and audit independent testing companies; prepared regulatory proposals and other presentations to classes at professional symposia and directly to the Air Resources Board at public hearings. As state representative, coordinated efforts with federal, local, and industrial representatives.

PROFESSIONAL AFFILIATIONS/ LICENSES

Past President, Professional Engineers in California
Government Fort Sutter Section;
Past Chairman, Legislative Committee for Professional Association of Air Quality Specialists. Have passed the Engineer in Training exam.

PUBLICATIONS, PROFESSIONAL PRESINTATIONS AND ACCOMPLISHMENTS

Authored staff reports published by the California Air Resources Board and presented papers regarding continuous emission monitoring at symposiums.

Authored a paper entitled "A Comprehensive Approach to Health Risk Assessment", presented at the New York Conference on Solid Waste Management and Materials Policy.

Authored a paper entitled "Risk Assessment A Tool For Decision Makers" at the Association of Environmental Professionals AEP Conference on Public Policy and Environmental Challenges.

Conducted a seminar at University of California, Los Angeles for the Doctoral programs in Environmental Science and Public Health on the subject of "Health Risk Assessment".

Authored a paper entitled "Uncertainty Analysis -An Essential Component of Health Risk Assessment and Risk Management" presented at the EPA/ORNL expert workshop on Risk Assessment for Municipal Waste Combustion: Deposition, Uncertainty, and Research Needs.

Presented a talk on off-site consequence analysis for extremely hazardous materials releases. Presented at the workshop for administering agencies conducted by the City of Los Angeles Fire Department.

Evaluated, provided analysis and testimony regarding public health and hazardous materials management issues associated with the permitting of more than 20 major power plants throughout California.

Developed Departmental policy, prepared policy documents, regulations, staff instruction, and other guidance documents and reference materials for use in evaluation of public health and hazardous materials management aspects of proposed power plants.

Project Manager on contracts totaling more than $500,000.

RES.RT

DECLARATION OF
William Walters, P.E.

I, **William Walters** declare as follows:

1. I am presently employed by Aspen Environmental Group, a contractor to the California Energy Commission, in the Agoura Hills office as an associate in engineering and physical sciences.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **VISUAL RESOURCES** (VISUAL PLUMES ANALYSIS) and **TRAFFIC AND TRANSPORTATION** (EXHAUST PLUME TURBULENCE), for the **BLYTHE ENERGY PROJECT PHASE II** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: March 24, 2005 Signed: _____

At: Agoura Hills, California

WILLIAM WALTERS, P.E.
Air Quality Specialist

ACADEMIC BACKGROUND

B.S., Chemical Engineering, 1985, Cornell University

PROFESSIONAL EXPERIENCE

Mr. Walters has over sixteen years of technical and project management experience in environmental compliance work, including environmental impact reports, RCRA/CERCLA site assessment and closure, site inspection, source monitoring, emissions inventories, source permitting, and energy and pollution control research.

Aspen Environmental Group **2000 to Present**

Responsible as lead technical and/or project manager of environmental projects. Specific responsibilities and projects include the following:

- Preparation and/or project management of the air quality section of the Staff Assessment and/or Initial Study for the following California Energy Commission (CEC) licensing projects:
  - Hanford Energy Park;
  - United Golden Gate, Phase I
  - Huntington Beach Modernization Project (including Expert Witness Testimony)
  - Woodland Generating Station 2
  - Ocotillo Energy Project, Phase I
  - Magnolia Power Project
  - Colusa Power Project
  - Henrietta Peaker Project
  - Tracy Peaking Power Plant Project (including Expert Witness Testimony)
  - San Joaquin Valley Energy Center (including Expert Witness Testimony)
  - Salton Sea Geothermal Unit #6 Power Project (including Expert Witness Testimony)
  - Modesto Irrigation District – MEGS Ripon (including Expert Witness Testimony)
  - Turlock Irrigation District - Walnut Energy Center (including Expert Witness Testimony)
  - Riverside Energy Resource Center (including Expert Witness Testimony)
- Assistance in the preparation of the noise assessment section of the Staff Assessment for the Contra Costa Power Plant CEC licensing project.
- Preparation of the staff paper "Emission Offsets Availability Issues", and preparation of the Emission Offsets Constraints Workshop Summary paper for the CEC.
- Preparation and project management of the public health section of the Initial Study for the Woodland Generating Station 2 CEC licensing project.
- Issue area coordinator providing support for the air quality analyses and/or visual plume assessments for the Inland Empire Energy Center, Los Esteros Critical Energy Facility, Palomar Energy Project, Avenal Energy Project, and the Tesla Power Plant Project.

- Preparation and/or project management of the visual plume assessment for the following California Energy Commission (CEC) licensing projects:
  - Metcalf Energy Center Power Project (including Expert Witness Testimony)
  - Contra Costa Power Plant Project (including Expert Witness Testimony)
  - Mountainview Power Project
  - Potrero Power Plant Project
  - El Segundo Modernization Project
  - Magnolia Power Project
  - Morro Bay Power Plant Project
  - Valero Cogeneration Project
  - East Altamont Energy Center (including Expert Witness Testimony)
  - Russell City Energy Center
  - SMUD Cosumnes Power Plant Project
  - City of Vernon Malburg Combined Cycle Plant
  - Inland Empire Energy Center
  - Palomar Energy Project
  - San Joaquin Valley Energy Center
  - Woodland Generating Station 2
  - Hanford Energy Park
  - United Golden Gate, Phase I
  - Huntington Beach Modernization Project
  - Ocotillo Energy Project, Phase I
  - Colusa Power Project
  - Henrietta Peaker Project
  - Tracy Peaking Power Plant Project
  - Avenal Energy Project
  - Salton Sea Geothermal Unit #6 Power Project
  - Turlock Irrigation District - Walnut Energy Center
  - Roseville Energy Park Project

- Preparation of project amendment or project compliance assessments, for air quality or visual plume impacts, for several licensed power plants, including: Metcalf Energy Center; Pastoria Power Plant; Elk Hills Power Plant; Henrietta Peaker Project; Tracy Peaker Project; Magnolia Power Project; Delta Energy Center; SMUD Cosumnes Power Plant; Walnut Energy Center; San Joaquin Valley Energy Center; City of Vernon Malburg Generating Station; Los Esteros Critical Energy Facility, Otay Mesa Power Plant; and Pico Power Project.

- Assistance in the aircraft safety review of thermal plume turbulence for the Riverside Energy Resources Center; and the Blythe Energy Power Plant and Blythe Energy Project Phase II (ongoing).

- Preparation and instruction of a visual water vapor plume modeling methodology class for the California Energy Commission.

- Preparation of the air quality section of the PG&E Hydrodivestiture Draft EIR/EIS for the California Public Utilities Commission (CPUC).

- Preparation of the Air Quality section for the Department of Water Resources Santa Ana Valley Pipeline Repairs Project CEQA Categorical Exemption Memorandum.

- Assistance in the preparation of the Air Quality Sections for the Department of Water Resources Tehachapi Second Afterbay Project Initial Study and EIR.
- Preparation of the Air Quality Section and General Conformity Analysis for the Matilija Dam Ecosystem Restoration Project EIS/R for the United States Army Corps of Engineers (Corps).
- Preparation of emission inventory and General Conformity Analysis of the Murrieta Creek Flood Control Project for the Corps.
- Emission inventory for the construction activities forecast for the San Jose/Old San Jose Creeks Ecosystem Restoration project for the Corps.
- Preparation of permit applications, emission calculation spreadsheets, and an air quality compliance manual for Desa International's Southern California manufacturing facility.
- Preparation of the Air Quality Section of the LAUSD New School Construction Program EIR and provided traffic trip and VMT calculation support for the Traffic and Transportation Section. As part of this project attended two public scoping meetings.
- Management and preparation of the Draft Air Quality Sections for the Reseda Senior High School Portable Addition IS/MND and Wonderland Elementary Addition IS/MND projects for LAUSD.
- Technical review and updating of the Air Quality Section for the Valley High School No. 1 EIR (CSUN) and Jefferson No. 6 Primary Center MND projects for LAUSD.
- Revision of the Risk Management Plan (RMP) for the SSI Foods Wilder Idaho Facility Ammonia Refrigeration Systems.
- Preparation of a control technology evaluation for the control of nuisance odors from wood-fired pizza ovens for the A16 restaurant in San Francisco, California.

Camp Dresser & McKee, Inc. **1998 to 2000**

Mr. Walters was responsible as lead technical and/or project manager of environmental projects. Specific responsibilities and projects include the following:

Preparation of emission inventories and dispersion modeling for criteria and air toxic pollutants for the Los Angeles International Airport Master Plan (LAXMP) EIS/EIR.

Project manager/technical lead for the completion of Risk Management Plans (RMPs) for four J.R. Simplot food processing facilities in Oregon, Idaho and Washington and the Consolidated Reprographics facility located in Irvine, California. Project manager for the concurrent Process Safety Management plan support for the J.R. Simplot Hermiston Oregon and Heyburn Idaho facilities and the project manager/technical lead for the RMP support for the SSI food processing facility in Wilder, Idaho and the Atlantic Custom Processors food processing facility in Fort Fairfield, Maine.

Project Manager/Technical lead for the completion of air permit applications and air compliance audits for two Desa International fireplace accessory manufacturing facilities located in Santa Ana, California.

Air quality audit for a confidential can manufacturing company at two manufacturing sites.

Completion of an environmental tax credit application for the J.R. Simplot Hermiston Oregon food products facility.

Planning Consultants Research **1997 to 1998**

Mr. Walters was responsible as lead technical and/or project manager of environmental projects. Specific responsibilities and projects include the following:

Project Manager for a stationary source emission audit of the entire Los Angeles International Airport complex for Los Angeles World Airports (LAWA) in support of the LAXMP.

Review of the Emission Dispersion Modeling System (EDMS) and preparation of a report with findings to the Federal Aviation Administration for LAWA in support of the LAXMP.

Project manager for the ambient air monitoring and deposition monitoring studies performed for LAWA in support of the LAXMP, including the selection of the monitoring sites and specialty subcontractor, and review of all monitoring data.

Completion of intersection "CO Hotspots" modeling, ambient monitoring, and deposition monitoring reports for LAWA in support of the LAXMP.

Aspen Environmental Group/Clean Air Solutions **1995 to 1996**

Mr. Walters was responsible as lead technical and/or project manager of environmental projects. Specific responsibilities and projects include the following:

Manager of the Portland, Oregon, office of Clean Air Solutions from March 1995 to December 1995, with responsibilities including Project Management, Business Development, and Administration.

Control technology assessment, engineering support and Notice of Intent to construct preparation for J.R. Simplot's Hermiston, Oregon food processing facility

Air quality compliance report including an air emission inventory, regulation and permit compliance determination, and recommendations for compliance for Lumber Tech, Inc.'s Lebanon, Oregon wood products facility.

Review and revision of an Air Contaminant Discharge Permit application, Title V permit application, and PSD modeling analysis for J.R. Simplot's Hermiston, Oregon food processing facility.

Source test methodology and equipment selection for testing inlet and outlet concentrations of total petroleum hydrocarbon and benzene from soil gas extraction/oxidation units for Cascade Earth Sciences, Ltd.

Preparation of a Tier II (synthetic minor) permit application for the American Fine Foods' Payette, Idaho food processing facility.

Emission inventory and compliance evaluation for Simplot's Aberdeen, Idaho food processing facility.

Preparation of an Air Contaminant Discharge permit application for Marlette Homes, Inc. Hermiston, Oregon manufactured housing facility.

Preparation of a Title V permit application for Simplot's Helm, California fertilizer manufacturing facility.

Source test contractor selection and test oversight for J.R. Simplot's food processing plant in Hermiston, Oregon, and Boise Cascade's wood-fired boiler in Willamina, Oregon.

Fluor Daniel, Inc. **1990 to 1995 and 1996 to 1997**

Mr. Walters was responsible as lead technical or project manager for major environmental projects for both government and private clients. His projects included:

Prepared several air permit applications for the ARCO Los Angeles Refinery Polypropylene Plant Project.

Phase I environmental assessments for seven properties located in Southern California.

Prepared Environmental Baseline Reports for 33 sites in Guam for the U.S. Navy.

Prepared site investigation and RCRA closure plan report for Olin Hunt Specialty Chemical's Vernon, California, hazardous waste storage site.

Project manager of the Anaconda Smelter site for the U.S. Environmental Protection Agency's (EPA) Alternative Remedial Contract System (ARCS) project during the conclusion of technical activities and project closeout. Prepared a cost recovery report for the project.

Task manager for nine site investigations under the EPA Region VI ARCS contract. Project activities included data collection, work plan preparation, field sampling, final report preparation, and Hazard Ranking System (HRS) PREscore preparation.

For the Hanford (Washington) Waste Vitrification Project,
- prepared an air emission inventory for criteria pollutants
- prepared an emission inventory and compliance evaluation of toxic air pollutants
- performed compliance review of design drawings and equipment specifications
- analyzed failure probability and consequence analysis of design-basis accidents.

Prepared fugitive and point source VOC emission estimates and performed a "Top-Down" BACT analysis for a 217 MMBtu/hr steam boiler for a proposed ethanol production facility in Great Falls, Montana.

Performed environmental analysis for the Bonneville Power Authority, including air pollution BACT analysis, wastewater analysis, and evaluation of secondary environmental effects of electric power producing technologies.

Jacobs Engineering Group **1988 to 1990**

Mr. Walters was responsible for a wide range of air pollution regulatory and testing projects, including the following:

Project manager of air toxic emission inventory reports (under California's AB2588), prepared for U.S. Borax's boron mining and refining facility and the Naval Aviation Depot (North Island Naval Base, San Diego, California).

Prepared air permit applications and regulatory correspondence for several facilities:

- U.S. Department of Energy's Feed Material Production Center uranium processing facility in Fernald, Ohio
  -Emission sources at a confidential high technology electronics manufacturing facility
- Evaluation of a sludge dewatering process at Unocal's Wilmington, California, Refinery
  -United Airlines blade repair facility at the San Francisco Airport
- Relocation of Kerr-McGee's rocket fuel storage and blending facility to Apex, Nevada.

Prepared source testing plans, Quality Assurance/Quality Control (QA/QC), and testing oversight for several facilities including:

-QA/QC for RCRA air emissions sampling plan for the Department of Defense's Chem-Demil facility on Johnston Atoll
- Prepared plan and provided QA/QC and field oversight for emissions testing at Baxter Healthcare in Irvine, California
- Prepared plan and provided testing oversight for Kerr-McGee's existing ammonium perchlorate manufacturing facility in Henderson, Nevada.

Completed identification of air permitting regulations and control technology requirements for a proposed 30,000 barrel per day catalytic cracking unit for Coastal Corporation's Pacific Refinery, located in Hercules, California.

Characterized and quantified air emissions for offshore oil and gas development activities associated with Federal oil and gas Lease Sale 95, offshore southern California, for the U.S. Minerals Management Service.

Assisted in selection and design of air pollution control equipment for various clients.

Prepared environmental reports, including waste stream quantification and characterization for several proposed facilities, including:

- Lake Minerals proposed soda ash plant at Owens Lake, California
- Minsal's proposed potash facility located on the Salar de Atacama in Chile.

San Joaquin County Air Pollution Control District **During 1987 and 1988**

Mr. Walters served as an air pollution engineer and was responsible for the following: start-up site inspections of air pollution sources; monitoring source tests and evaluating source test reports; permitting minor and major sources of air pollutants; processing emission banking applications; and aiding in the preparation of the District's Best Available Control Technology (BACT) quarterly reports, Reasonable Further Progress reports, and emission inventories.

Adelphi Center for Energy Studies **1985 to 1986**

Mr. Walters served as a combustion facility manager/research engineer and was responsible for the following: management and implementation of all conventional and novel fuel combustion projects, including the preparation of interim and final reports, conducting source tests using EPA methods 1-4 and 17, and the data analysis of all combustion tests; maintenance and repair of all combustion facility equipment; preparation of all combustion project proposals; and implementation and data analysis of fuel atomization studies, fuel rheology research, and bench scale coal ash removal research.

CERTIFICATIONS

Chemical Engineer, California License 5973
CARB, Fundamentals of Enforcement Seminar
EPA Methods 1-8, 17; Training Seminar

PAPERS

Authored

"Current and Future Air Pollution Emission Offset Requirements, and Impacts to the Pacific Northwest". PNWIS/CPANS Air and Waste Management Chapters Annual Meeting. November 17, 1995.

Co-Authored

"Gas Co-Firing of the CWF for Package Boiler Applications", Presented at the Third Annual Pittsburgh Coal Conference, September 1986.

"Implications of Slurry Fuel Rheology on Atomization," American Society of Engineers.

"Factors Affecting Atomization of CWF", Presented at the Eighth International Symposium of Coal Slurry Fuel Preparation and Utilization. Orlando, FL May 1986.