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SONORAN ENERGY PROJECT

Preliminary Staff Assessment for the Petition to Amend the Sonoran Energy Project (Formerly Blythe Energy Project Phase II) Decision

CALIFORNIA
ENERGY COMMISSION
Edmund G. Brown, Jr, Governor

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INTRODUCTION

This Preliminary Staff Assessment (PSA) is being published by California Energy Commission (Energy Commission) staff for the Petition to Amend (PTA) the Blythe Energy Project Phase II (BEP II). AltaGas Sonoran Energy, Inc. (AltaGas), the project owner, is proposing to update the project's technology and design in an effort to construct a least cost, best fit project while taking into account the current energy market and environmental conditions. On December 14, 2005, the Energy Commission granted a license (2005 Decision) to Caithness Blythe II, LLC, to construct the nominal 520 megawatt (MW) combined-cycle BEP II. On April 26, 2012, an amendment to the license was approved by the Energy Commission (2012 Order) to modify the BEP II to be a nominal 569 MW combined-cycle facility.

This PSA contains staff's independent, objective evaluation of AltaGas's PTA which was filed on August 7, 2015. The analyses are similar to those normally contained in a Supplemental Environmental Impact Report (EIR) prepared in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162).

For an amendment to an existing power plant over which it has regulatory oversight, the Energy Commission is the lead state agency under CEQA. The Energy Commission's certified regulatory program provides the environmental analysis that satisfies CEQA requirements. In fulfilling this responsibility, Energy Commission staff provides an independent assessment of the amendment's engineering design, evaluates its potential effects on the environment and on public health and safety, and determines whether the project, if modified, would remain in conformance with all applicable local, state, and federal laws, ordinances, regulations and standards (LORS). Energy Commission staff also recommends any needed modifications to existing mitigation measures (known as conditions of certification) in the Energy Commission Final Decision and proposes additional conditions of certification to mitigate any significant adverse environmental effects of the proposed modifications.

This PSA is not 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, and federal LORS. The Final Staff Assessment (FSA) will be prepared after staff receives and addresses comments and completes its analysis. In the evidentiary hearings, the Committee will consider the recommendations presented by staff, the petitioner, intervenors, governmental agencies, tribes, and the public prior to submitting its proposed decision (Presiding Member's Proposed Decision (PMPD)) to the full Commission. Following a public hearing(s), the full Commission will make a final decision on the proposed modifications.

In light of current environmental conditions and updated policy considerations, Water Resources staff recommends that the amended SEP be modified to incorporate dry cooling to address project water use impacts. The project's cooling system and related impacts are analyzed and discussed in detail within the **Soil and Water Resources** section of this analysis. Accordingly, Condition of Certification **SOIL&WATER-10** includes staff's recommended changes to significantly reduce the project's annual water use limit, which could be achieved by incorporating a dry cooling system. The **Air Quality**, **Land Use**, **Biological Resources**, **Visual Resources**, **Noise and Vibration**, **Public Health**, **Socioeconomics,** and **Traffic and Transportation** sections of this document have also addressed the issue of incorporating dry cooling.

The use of evaporation ponds, as described in the PTA, is incompatible with Conditions of Certification **BIO-12** and **WATER QUALITY-5** as outlined in the 2005 Decision. The 2005 Decision states that "*Facility wastewaters will be handled through a Zero Liquid Discharge (ZLD) process. A stand-by evaporation pond will be used for processed wastewaters only when the ZLD system is unavailable*." These two conditions of certification would allow wastewater discharge to evaporation ponds only in the cases of cooling system initial commissioning and maintenance, planned or forced outages of the approved ZLD system, or emergencies. The use of evaporation ponds instead of a ZLD system are discussed in the **Biological Resources**, **Soil and Water Resources**, **Land Use**, and **Traffic and Transportation** sections of this document.

PROPOSED PROJECT LOCATION AND DESCRIPTION

The SEP site is located within the city of Blythe, approximately five miles west of the city center, and approximately 1 mile east of the Blythe Airport, in eastern Riverside County.

The proposed SEP is a natural gas-fired, water-cooled, combined-cycle, 553-MW net electrical generating facility. Primary modifications to the approved BEP II include the name change of the project to the SEP. Other modifications proposed for the project include the following:

- Define a new point of electrical interconnection via a 1,320-foot, 161-kV transmission line to the Western Area Power Administration's Blythe substation located southeast of the project site via an existing transmission line located in the Southern California Edison (SCE) Buck Boulevard substation;
- Replace the two Siemens SGT6-5000F combustion turbines with a single, more efficient General Electric (GE) Frame 7HA.02 combustion turbine;
- Replace the Siemens steam turbine generator (STG) with a more efficient single-shaft GE D652 STG;
- Increase the size of the auxiliary boiler to support GE's rapid response fast start capability;
- Decrease the size of cooling tower from an 11-cell to a 10-cell tower in response to the reduced heat rejection requirements;
- Decrease the size of the emergency diesel fire pump engine; and

- Optimize the general arrangement.

PURPOSE AND NEED FOR AN AMENDMENT

The purpose of this PTA is to (1) change the name of the project form Blythe Energy Project Phase II to the Sonoran Energy Project; and (2) to update project technology and design. This PTA proposes to change the combustion/turbine/steam turbine technologies since those being proposed were unavailable during the licensing of the project. Further, AltaGas acquired the SEP site license in May 2014 and has been working since that time on developing a project that will support the integration of renewables by providing efficient, fast-starting, fast-ramping, lower-minimum-operating-load, highly-efficient combined-cycle gas-fired generation that will utilize dry combustors and water treatment of cooling tower influent and share certain infrastructure with the existing, operational Blythe Energy project (BEP).

CUMULATIVE IMPACTS

See **Attachment A** at end of this section.

ENVIRONMENTAL JUSTICE

Environmental justice communities are commonly identified as those where residents are predominantly minorities or low-income; where residents have been excluded from the environmental policy setting or decision-making process; where they are subject to a disproportionate impact from one or more environmental hazards; and where residents experience disparate implementation of environmental regulations, requirements, practices, and activities in their communities. Environmental justice efforts attempt to address the inequities of environmental protection in these communities.

An environmental justice analysis is composed of three parts:

1. Identification of areas potentially affected by various emissions or impacts from a proposed project;
2. A determination of whether there is a significant population of minority persons or persons below the poverty level living in an area potentially affected by the proposed project; and
3. A determination of whether there may be a significant adverse impact on a population of minority persons or persons below the poverty level caused by the proposed project alone, or in combination with other existing and/or planned projects in the area.

California law defines environmental justice as “the fair treatment of people of all races, cultures and income with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies” (Gov. Code §65040.12; Pub. Resources Code, §§ 71000-71400). All departments, boards, commissions, conservancies and special programs of the Resources Agency must consider environmental justice in their decision-making process if their actions have an impact on the environment, environmental laws, or policies. Such actions that require environmental justice consideration may include:

- Adopting regulations;
- Enforcing environmental laws or regulations;
- Making discretionary decisions or taking actions that affect the environment;
- Providing funding for activities affecting the environment; and
- Interacting with the public on environmental issues.

DEMOGRAPHIC SCREENING ANALYSIS

As part of its CEQA analysis for the PTA, Energy Commission staff used demographic screening to determine whether a minority and/or low-income population exists within the potentially affected area of the proposed SEP site. The demographic screening is based on information contained in two documents: *Environmental Justice: Guidance Under the National Environmental Policy Act* (CEQ, 1997) and *Guidance for Incorporating Environmental Justice Concerns in EPA's Compliance Analyses* (US EPA, 1998), which provides staff with information on outreach and public involvement.

Minority Populations

According to *Environmental Justice: Guidance under the National Environmental Policy Act*, minority individuals are defined as members of the following groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic. An environmental justice population is identified when one or more U.S. Census blocks in the potentially affected area have a minority population greater than or equal to 50 percent. **Socioeconomics Figure 1** shows that the population in these census blocks represents an environmental justice population as defined by *Environmental Justice: Guidance under the National Environmental Policy Act*. Refer to the **Socioeconomics** section of this document.

SUMMARY OF ENVIRONMENTAL CONSEQUENCES AND MITIGATION

Below is a summary of environmental consequences of the amended project and mitigation proposed in this PSA. This section also provides a summary of outstanding information that will be analyzed in the FSA. The summary table also includes the determination for each discipline whether the modified project would continue to comply with applicable LORS.

Executive Summary - Table 1
Environmental and Engineering Assessment and LORS Compliance

Technical Area	Complies with LORS	Impacts Mitigated	Additional Information Required
Air Quality/Greenhouse gases	Yes	Yes	No
Biological Resources	No	No	No
Cultural Resources	Undetermined	Yes	Yes
Hazardous Materials	Yes	Yes	Yes
Land Use	No	No	Yes
Noise and Vibration	Yes	Yes	No
Public Health	Yes	Yes	No
Socioeconomics	Yes	Yes	No
Soil and Water Resources	Yes	Yes	No
Traffic & Transportation	No	No	Yes
Transmission Line Safety/Nuisance	Yes	Yes	No
Visual Resources	Yes	Yes	No
Waste Management	Yes	Yes	No
Worker Safety and Fire Protection	Yes	Yes	No
Facility Design	Yes	Yes	No
Geology & Paleontology	Yes	Yes	No
Power Plant Efficiency	N/A	Yes	No
Power Plant Reliability	N/A	Yes	No
Transmission System Engineering	Yes	Undetermined	Yes
Alternatives	N/A	N/A	No

AIR QUALITY/GREENHOUSE GASES

Staff concludes that with the adoption of the modified conditions of certification, the proposed SEP would not result in significant air quality related impacts during project construction and operation, and that the SEP would comply with all applicable federal, state and Mojave Desert Air Quality Management District air quality LORS.

If the project design includes an air cooled condenser (ACC or dry cooling) instead of a wet cooling tower, criteria air pollutants from the cooling tower would be avoided. But emissions from the combustion turbine and heat recovery steam generator might increase or decrease, depending on how the project owner sizes the ACC and incorporates the ACC into the project design and operations. Staff does not see any fatal flaws in the area of Air Quality in incorporating an ACC into the SEP project design.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in **Air Quality Appendix AIR-1**. As discussed there, the SEP would comply with the Emission Performance Standard established by Senate Bill 1368 for base load generation. The project would also be subject to federal and Air Resources Board mandatory GHG reporting requirements and any GHG reduction or trading requirements developed by the ARB as GHG regulations are implemented.

BIOLOGICAL RESOURCES

Staff concludes that the SEP's proposed use of evaporation ponds would result in new significant direct and cumulative impacts to biological resources, impacts that the approved BEP II using zero liquid discharge (ZLD) technology would have avoided. Conditions of Certification **BIO-12** and **WATER QUALITY-5** (renumbered **SOIL&WATER-4** in the **Water Resources** section of this document) allow wastewater discharge to evaporation ponds only in the cases of cooling system initial commissioning and maintenance, planned or forced outages of the ZLD system, or emergencies. During these limited periods, **BIO-12** requires implementation of an Evaporation Pond Mitigation and Monitoring Plan to avoid impacts to biological resources from exposure to wastewater discharges. The use of evaporation ponds as described in the PTA is incompatible with **BIO-12**, and the project owner has not proposed any alternative measures to avoid or mitigate potentially significant impacts to migratory birds. Staff understands the project owner is currently evaluating options for wastewater discharge. Staff continues to recommend the use of ZLD to avoid impacts to migratory birds and ensuring compliance with the Migratory Bird Treaty Act.

Dry cooling, as proposed by Soil and Water staff, would substantially reduce the amount of SEP's wastewater. The amount of wastewater reduction and the available capacity at the existing BEP ponds are factors in determining if using the existing ponds (as recommended by USFWS) for SEP's wastewater is feasible. ZLD or other wastewater handling technologies combined with dry cooling may also be feasible options for avoiding using, or constructing new, evaporation ponds.

Staff concludes that the new route of the transmission (gen-tie) line would not disturb or impact any sensitive habitat or special-status plants or wildlife. With implementation of Conditions of Certification **BIO-1** through **BIO-11** in the 2005 Decision, impacts to sensitive biological resources that may occur during construction of the amended project would be mitigated to less than significant and ensure these construction activities comply with LORS.

CULTURAL RESOURCES

Staff concludes that the proposed amendment would have no new cultural resources impacts, and mitigation measures for the original project would still be applicable and would not require any substantive changes. Therefore, staff also concludes that the findings of fact from the 2005 Decision would still apply to the amended SEP:

- If a buried cultural resource meeting eligibility requirements is discovered during construction, then Conditions of Certification **CUL-1** through **CUL-7** would reduce the impacts to less than significant;
- 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 Condition of Certification **CUL-7**. Mitigation measures required under Condition of Certification **CUL-7** would reduce the impacts to less than significant and ensure compliance with applicable LORS;
- Condition of Certification **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. However, it is indeterminate to staff if the Memorandum of Agreement (MOA), pursuant to Section 106 of the National Historic Preservation Act, is still applicable to the project, and further if the MOA obligations were transferred from Caithness to AltaGas as specified in the condition;
- As a result of past Western Area Power Administration (Western) tribal consultations, staff identified significant off-site cultural resources that would be cumulatively impacted by the BEP II. Condition of Certification **CUL-9** is a measure that would reduce those impacts to less than significant. However discrepancies among 1) the list of tribes contacted in 2005 when there was a past federal (Western) nexus to the project, 2) the list of tribes named in **CUL-9,** and 3) the list of tribes that staff routinely consults with on projects in the same area and over the last 5 years may result in future revisions to Condition of Certification **CUL-9**; and
- Condition of Certification **CUL-10** requires that the Energy Commission be informed of the compliance with federal historic preservation laws as further stipulated in the MOA mentioned in **CUL-8** and **CUL-10**. **CUL-10** may be subject to revision based upon ongoing consultation with Western and the State Office of Historic Preservation concerning 1) the current status towards completing the stipulations of the MOA, and 2) the continued applicability of the MOA for the SEP.

HAZARDOUS MATERIALS

Pending receipt and review of the requested supplemental Offsite Consequence Analysis (OCA) information before staff's FSA, staff expects that the proposed amendment will not present any increase in the potential for significant impacts to the public or the environment resulting from the use of hazardous materials at the project. Without the OCA, staff is unable to conclude that no supplementation to the 2005 Decision and 2012 Order is needed.

Staff also expects the supplemental OCA information, with the existing conditions of certification resulting from the original decision and subsequent PTA (with one change), hazardous materials storage and use at the SEP would comply with all applicable LORS and would not result in any unmitigated significant potential impacts to the public or environment.

LAND USE

Staff concludes that the SEP could potentially result in more severe land use impacts from thermal plumes, which would affect aircraft safety and make the SEP incompatible with the Blythe Airport, a surrounding land use, and the Riverside County Airport Land Use Commission Plan (ALUCP). Thermal plume impacts could potentially be increased due to the proposed change in technology for the SEP, and also from the potential infeasibility of implementing parts of Condition of Certification **TRANS-9**, which the 2005 Decision included to mitigate impacts to aircraft safety. See the **Traffic and Transportation** section of this PSA for more information.

The project could also result in new land use impacts from evaporation ponds by attracting birds to the site, impacting aviation safety and resulting in the project being incompatible with the Blythe Airport and Riverside County ALUCP. See the **Traffic and Transportation** section of this PSA for more information. Staff understands the project owner is currently evaluating additional options for wastewater discharge. Staff continues to recommend the ZLD process approved in the 2005 Decision, which would avoid these impacts. See the **Biological Resources** section of this PSA for more information on this recommendation.

Finally, the project could combine with other projects in the area to cause significant cumulative impacts to aviation safety and make the project incompatible with the Blythe Airport and Riverside County ALUCP. To analyze these impacts, staff would need to rely on **Traffic and Transportation** staff's analysis of cumulative impacts to aviation safety from the SEP's thermal plumes. **Traffic and Transportation** staff does not yet have the necessary information to complete this analysis, and therefore, Land Use staff cannot yet determine whether there would be any significant cumulative impacts to land use compatibility between the project and the Blythe Airport.

In the event that dry-cooling becomes part of the SEP project description, reduced water use would mean that the project owner could retire a smaller amount of agricultural land as part of the Water Conservation Offset Program (WCOP). As a result, to fulfill the requirements of **LAND-3**, which requires that the project owner mitigate for any agricultural land permanently fallowed as part of the WCOP, the project owner would be able to pay lower mitigation fees or secure an easement for a smaller amount of agricultural land. If the SEP project owner participates in the WCOP by rotational fallowing, rather than permanent retirement of irrigated agricultural land, impacts to agricultural lands would be less than significant and would not need mitigation by **LAND-3**.

The ACC could require a height variance for LORS conformance. The city's March 2004 variance findings for the BEP II would not necessarily apply to the ACC because the

ACC would increase the project's bulk through its height, width, and depth. Staff is coordinating with the city of Blythe to determine whether an additional variance would be needed in this situation.

NOISE AND VIBRATION

Existing Conditions of Certification **NOISE-1**, **NOISE-2**, **NOISE-3**, **NOISE-4, NOISE-5**, **NOISE-7**, and **NOISE-8** and the proposed minor revisions to Condition of Certification **NOISE-6** would be sufficient to reduce impacts from the proposed amendment to a less than significant level directly, indirectly, and cumulatively and to ensure the project remains in compliance with applicable LORS relating to noise and vibration. The revised **NOISE-6** does not affect **Noise and Vibration** conclusions made in the 2005 Decision.

PUBLIC HEALTH

Similar to the conclusions in the project's 2005 Decision, the potential impacts of the toxic pollutants of concern in this analysis would be less than significant. Staff has evaluated the validity of the owner's health risk assessment and established that the proposed technological modification would not affect SEP's ability to comply with applicable health LORS. Staff concludes that no supplementation to the 2005 Decision is necessary for **Public Health**. Staff recommends approval of the owner's request to delete the Condition of Certification **PUBLIC HEALTH-1** related to the project's cooling tower design, construction and operation. If dry cooling were to be utilized, **PUBLIC HEALTH-2** would not be necessary and staff would also recommend its deletion. Staff does not anticipate any other changes to the public health analysis with the incorporation of dry cooling.

SOCIOECONOMICS

Staff concludes that the proposed amendment would have no new socioeconomic impacts and the mitigation for the BEP II would still be applicable and would not require any substantive changes. Staff also concludes that the findings in the 2005 Decision and 2012 Order would still apply to the amended SEP. Staff concludes that no supplementation to the 2005 Commission Decision is necessary for Socioeconomics. The Committee may rely upon the environmental analysis and conclusions of the 2005 Decision with regards to Socioeconomics and does not need to re-analyze them. In the event dry cooling becomes part of the SEP project description, the existing Condition of Certification **SOCIO-2** would no longer be necessary.

SOIL & WATER RESOURCES

The SEP PTA does not seek to modify the existing **Soil & Water Resources** Conditions of Certification, but staff is recommending modifications for reasons outlined below. Staff concludes that a supplementation to the 2005 Decision is necessary for **Soil & Water Resources**. The Committee should re-analyze the conclusions of the 2005 Decision alongside this new information.

Staff augments the existing record to reflect current environmental conditions and updated policy considerations. Similar to staff conclusions during the licensing of the

BEP II project in 2005, staff believes the SEP should implement dry cooling to address project water use impacts. In addition to the project's use of wet cooling not complying with state water policy, the Palo Verde Mesa basin is now supporting unsustainable groundwater pumping. The additional groundwater demand required by the SEP would be expected to result in significant impacts to the Palo Verde Mesa groundwater basin and flows in the Colorado River.

The SEP would rely on groundwater and irrigation water that is destined for the Colorado River. Staff is concerned that the projected decrease in Colorado River flows in the future could impact the SEP's reliability. Staff does not believe that an unmetered take from the Colorado River is sustainable. In the recent past, pumpers of Colorado River water were expecting to fall under the Accounting Surface Rule. In the more recent past, many power plants in California have struggled to maintain reliable water supplies when facing competing uses, changing California weather patterns, and local and regional droughts.

The use of high quality groundwater for cooling is highly discouraged by state water policies both old and new. Since the 2005 Decision, the Sustainable Groundwater Management Act (SGMA) has been adopted. This law requires sustainable management of California groundwater basins. The SEP would put the Palo Verde Mesa further into an unsustainable condition.

The project owner has not produced meaningful evidence they can develop and implement a Water Conservation Offset Plan (WCOP) that would offset project groundwater use in accordance with the 2005 Decision. Staff is concerned that the owner would have great difficulty achieving the necessary offset. The 2005 Decision states, "To avoid potential environmental impacts, the WCOP needs to include measures to protect from erosion and to verify true water conservation from qualifying farmlands." Since 2005, farmlands available for water offset have become scarce in the Palo Verde area; many pieces of land have already been purchased for this purpose by Metropolitan Water District (MWD). Staff is also concerned that there may not be enough fallow-able land available on the Palo Verde Mesa or Valley to meet the project's needs. The cost to produce a commensurate offset could also be cost prohibitive for the owner. Staff concludes that since it is unlikely the project owner can demonstrate there is real water savings that would benefit the basin and the river, the project owner should be required to implement a dry cooled design.

The Energy Commission staff-prepared Water Supply Assessment indicates that the water supply of the Palo Verde Mesa basin cannot support the SEP. The project also cannot comply with state water policy due to its high water demand and use of high quality water. It is unreasonable to permit such excessive water use when other feasible and economical technologies exist. It is important to note that efforts are being made all along the Colorado River to conserve water resources and augment supplies. Conservation will be necessary to meet the future needs of the river.

Staff recommends that the SEP be modified to incorporate dry-cooling. Though the proposed use of water is not currently regulated under the Accounting Surface Rule, it is not adequately reliable, and it is not adequately drought-proof. A dry cooled version of the project would still be expected to be profitable and meet the project's objectives.

Staff suggests minor revisions to some of the Conditions of Certification. Some of the conditions could require additional modification if the project were to switch to dry-cooling.

TRAFFIC & TRANSPORTATION

Staff concludes that SEP would create new, potentially significant direct and cumulative traffic and transportation impacts and would not comply with applicable LORS. The proposed use of evaporation ponds is inconsistent with the provisions of the Riverside County ALUCP, which prohibits land use development in compatibility zones "C" and "D" of the Blythe Airport that may increase the attraction of birds. The potential for evaporation ponds to attract birds, which could collide with airplanes using the Blythe Airport, was an issue addressed in the 2005 Decision but resolved by the original project applicant modifying the BEPII by substituting evaporation ponds for a ZLD system.

In addition, the 2005 Decision includes Condition of Certification **TRANS-9**, which specifies that project construction cannot start until the measures specified in the condition to mitigate aviation safety impacts from thermal plumes are accomplished. The PTA proposes to modify **TRANS-9** in a way that the project owner will have satisfied the condition by merely "requesting" that the Federal Aviation Administration (FAA) implement the measures. No alternative mitigation measures are proposed in the event the FAA does not agree to implement the measures in **TRANS-9**, despite the project owner's thermal plume modeling results which predict higher velocity plumes from the SEP compared to the BEP II. The 2005 Decision acknowledges that the measures agreed to by the original project applicant require FAA approval, and states that "the Commission shall retain jurisdiction to impose or, as appropriate, seek the FAA's imposition of alternate or additional measures if circumstances warrant" (page 190).

TRANSMISSION LINE SAFETY AND NUISANCE

The SEP PTA proposes project modifications that will not change existing **Transmission Line Safety and Nuisance (TLSN)** Conditions of Certification. Similar to the conclusions in the project's 2005 Decision, the potential impacts of the proposed SEP would be less than significant. Staff concludes that no supplementation to the 2005 Decision is necessary for **TLSN**. The Committee may rely upon the environmental analysis and conclusions of the 2005 Commission Decision with regards to **TLSN** and does not need to re-analyze them.

The proposed modifications would involve specific changes to the approved power transmission scheme as necessary to ensure implementation of applicable mitigation measures. Staff's assessment shows the proposed design and operational plan would not affect the ability of SEP to comply with the LORS given that the previously-approved conditions of certification would be retained. Staff are not proposing revisions to existing **TLSN** Conditions of Certification

VISUAL RESOURCES

Staff has reviewed the petition to amend the BEP II 2005 Decision for the proposed SEP to determine potential visual impacts and consistency with applicable LORS. Based on this review, staff determined that the proposed SEP would not create new significant visual impacts or make substantially more severe the significant visual impacts analyzed in the 2005 Decision, and that the proposed SEP would be in compliance with all applicable LORS, with effective implementation of the Conditions of Certifications approved in the 2005 Decision. None of the Conditions of Certifications are new or have been modified since the 2005 Decision. Staff concludes that supplementation to the 2005 Decision is necessary for visual resources. This analysis does not consider the effects of dry cooling. The visual impacts of an ACC unit will be included in the FSA.

WASTE MANAGEMENT

The SEP PTA proposes project modifications that will not necessitate changing the existing **Waste Management** Conditions of Certification. Similar to the conclusions in the 2005 Decision, the potential impacts of the proposed PTA would be less than significant. Staff concludes that no supplementation to the 2005 Decision is necessary for **Waste Management**. The Committee may rely upon the environmental analysis and conclusions of the 2005 Decision with regards to **Waste Management** and does not need to re-analyze them.

Management of the waste generated during construction and operation of the proposed amended SEP would not generate a significant adverse impact for Waste Management. Similar to the 2005 Decision, there is sufficient landfill capacity for the amended SEP. The 2005 Decision was not altered or affected by the 2009 PTA and the resulting 2012 Order. There is no evidence of soil contamination on the project site. As with the licensed BEP II, the amended SEP would be consistent with the applicable waste management LORS if staff's proposed conditions of certification are implemented.

WORKER SAFETY AND FIRE PROTECTION

The SEP PTA proposes to modify the project which will not necessitate modification to the existing set of **Worker Safety/Fire Protection** Conditions of Certification. Similar to the conclusions in the project's licensed BEP II 2005 Decision, and the 2012 Order, the potential impacts of the proposed PTA would be less than significant. Staff concludes that that the committee may rely upon the environmental analysis and conclusions of the 2005 Decision and 2012 Order with regards to **Worker Safety/Fire Protection** and does not need to re-analyze them.

Staff determined that only one of the LORS applicable to the project has changed since the 2012 Order. The one LORS that has changed is an update of the adopted California Fire Code. Staff further proposes a new Condition of Certification **WORKER SAFETY-7** that would clarify that conformance to the recommended practices of fire protection standard NFPA 850 is required.

FACILITY DESIGN

Similar to the conclusions in the 2005 Decision for the BEP II, the potential impacts of the proposed amendment would be less than significant. Staff concludes that no supplementation to the 2005 Decision is necessary for **Facility Design**, and that the amended project would comply with applicable engineering LORS. The Committee may rely upon the analysis and conclusions of the 2005 Decision with regards to **Facility Design** and does not need to re-analyze them.

GEOLOGY AND PALEONTOLOGY

The SEP PTA does not seek to modify the existing **Geology & Paleontology** Conditions of Certification. Similar to the conclusions in the 2005 Decision, the potential impacts of the proposed PTA would be less than significant. Staff concludes that no supplementation to the 2005 Commission Decision is necessary for Geology & Paleontology. The Committee may rely upon the environmental analysis and conclusions of the 2005 Commission Decision with regards to Geology & Paleontology and does not need to re-analyze them. However, staff is proposing the addition of two new conditions of certification and minor changes to update the existing Conditions of Certifications in this section for the purpose of making the existing requirements more clear.

POWER PLANT EFFICIENCY

The SEP thermal efficiency would compare favorably with the efficiency of similar combined cycle electric generation power plants that provide rapid-response capability, including the BEP II. The source of natural gas fuel for the amended project would be reliable.

Similar to the conclusions in the 2005 Decision for the BEP II, the amended project would create no significant impacts related to power plant efficiency. Dtaff concludes that no supplementation to the 2005 Decision is necessary for **Power Plant Efficiency**. The Committee may rely upon the analysis and conclusions of the 2005 Decision with regards to **Power Plant Efficiency** and does not need to re-analyze them.

POWER PLANT RELIABILITY

Similar to the conclusions in the 2005 Decision for the BEP II, the SEP would be built and would operate in a manner consistent with industry norms for reliable operation and would maintain a level of reliability which equals or exceeds reliability of similar operating electric generation facilities. Also similar to the BEP II, the amended project would create no significant impacts related to power plant reliability. Staff concludes that no supplementation to the 2005 Decision is necessary for **Power Plant Reliability**. The Committee may rely upon the analysis and conclusions of the 2005 Decision with regards to **Power Plant Reliability** and does not need to re-analyze them.

TRANSMISSION SYSTEM ENGINEERING

The SEP PTA proposes to modify the project which will necessitate modification to existing **Transmission System Engineering** Conditions of Certification. Currently, staff requires more information on proposed changes to the transmission interconnection and potential impacts on existing transmission networks. Staff is unable to conclude that no supplementation to the Blythe Energy Project 2005 Decision (2005 Decision) is necessary for **Transmission System Engineering**.

Staff recommends revising Conditions of Certifications **TSE-1** through **TSE-8**, as amended, to ensure that the proposed facilities are designed, built and operated in accordance with good utility practices and applicable LORS. Staff may include further changes in the FSA depending on the information provided in the Western Facilities Study and an Affected System Impact Study (SIS) by Southern California Edison (SCE) or the results of consultations with SCE and the Applicant.

1. The SIS indicated that there could be downstream project impacts that may require environmental analysis in the Energy Commission staff assessment. These impacts cannot be identified without the Western Detailed Facilities Study, and the results of an Affected SIS or a consultation with SCE, which the project owner has agreed to provide when they are available; and
2. Staff has updated the proposed conditions of certification to include standards required for an interconnection that affects the Western and SCE systems.

At this time, staff is unable to determine whether the proposed changes would comply with applicable LORS. The project owner has not provided some of the information about the proposed generator-tie line and the termination facilities at the Western Buck Blvd 161 kV Switching station, and the impacts on the Western and SCE systems are still unknown.

ALTERNATIVES

Staff reviewed alternatives previously analyzed for the licensed BEP II design and related facilities, alternative sites, and the “no project” alternative. Staff also reviewed the preferred resource alternatives of renewable generation technologies, which were previously analyzed, including central-station solar, geothermal, biomass, and wind. In addition, staff provided a discussion of “more preferred” resources including energy efficiency and demand response programs, distributed generation, and energy storage, which were not considered in previous staff assessments of the BEP II. Alternatives previously found to be infeasible would not now be feasible, and would not substantially reduce one or more significant effects of the BEP II. In addition, new information does not show alternatives which are considerably different from those analyzed in the previous staff assessment for the BEP II would substantially reduce one or more significant effects on the environment.

Staff concludes that no supplementation to the 2005 Commission Decision is necessary for Alternatives. The Committee may rely upon the environmental analysis and conclusions of the 2005 Commission Decision with regards to Alternatives and does not need to re-analyze them.

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CBE2002a. Caithness Blythe Energy, Inc. Application for Certification (AFC), Vol. 1 & Vol. 2. (TN 24604). Docketed on 02/19/2002.

CBE2002b. Caithness Blythe Energy, Inc. Revised Application for Certification for Blythe II. (TN 26100) Docketed on 07/03/2002.

CBE2009a. Caithness Blythe Energy, Inc. Phase II Amendment (TN 53798). Docketed on 10/26/2009.

CBE2010a. Caithness Blythe Energy, Inc. Supplement #1 to Amendment (TN 55438). Docketed on 2/16/2010.

CBE2011a. Caithness Blythe Energy, Inc. Blythe II Amendment Supplement #3 (TN 62479). Docketed 10/4/2011.

CBE2011b. Caithness Blythe Energy, Inc. 2009 Petition to Amend Supplement #2 (TN 63093). Docketed on 12/9/2011.

CEC2012a. California Energy Commission. Petition to Amend – Staff Analysis (TN 60499). Docketed on 3/12/2012.

CEC2012b. California Energy Commission. Commission Order Approving Petition to Amend (TN 64945). Docketed on 4/26/2012.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2005b. California Energy Commission. Commission Final Decision. Docketed Publication number CEC-800-2005-005-CMF. December 2005.

CEQ 1997 – Council on Environmental Quality. *Environmental Justice: Guidance Under the National Environmental Policy Act. December 10,* 1997, <http://www.epa.gov/compliance/ej/resources/policy/ej_guidance_nepa_ceq1297.pdf>.

US EPA 1998 – United States Environmental Protection Agency, *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses*. April 1998. <http://www.epa.gov/compliance/ej/resources/policy/ej_guidance_nepa_epa0498.pdf>.

EXECUTIVE SUMMARY
CUMULATIVE IMPACTS ATTACHMENT A

CUMULATIVE IMPACTS

Preparation of a cumulative impact analysis is required under CEQA. In the CEQA Guidelines, “a cumulative impact consists of an impact which is created as a result of the combination of the project evaluated in the EIR together with other projects causing related impacts” (14 Cal. Code Regs., §15130(a)(1)). Cumulative impacts must be addressed if the incremental effect of a project, combined with the effects of other projects is “cumulatively considerable” (14 Cal. Code Regs., §15130(a)). Such incremental effects are to be “viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects” (14 Cal. Code Regs., §15164(b)(1)). Together, these projects comprise the cumulative scenario which forms the basis of the cumulative impact analysis.

CEQA also states that both the severity of impacts and the likelihood of their occurrence are to be reflected in the discussion, “but the discussion need not provide as great detail as is provided for the effects attributable to the project alone. The discussion of cumulative impacts shall be guided by standards of practicality and reasonableness, and shall focus on the cumulative impact to which the identified other projects contribute rather than the attributes of other projects which do not contribute to the cumulative impact” (14 Cal. Code Regs., §15130(b)).

DEFINITION OF THE CUMULATIVE PROJECT SCENARIO

Cumulative impacts analysis is intended to identify past, present, and probable future actions that are closely related either in time or location to the project being considered, and consider how they have harmed or may harm the environment. Most of the projects listed in the cumulative projects tables (**Executive Summary - Appendix A Table 1)** and corresponding figure (**Executive Summary - Cumulative Impacts Figure 1**) have, are, or will be required to undergo their own independent environmental reviews under CEQA.

Under CEQA, there are two acceptable and commonly used methodologies for establishing the cumulative impact setting or scenario: the “list approach” and the “projections approach.” The first approach would use a “list of past, present, and probable future projects producing related or cumulative impacts.” (14 Cal. Code Regs., §15130(b)(1)(A)). The second approach is to use a “summary of projections contained in an adopted general plan or related planning document, or in a prior environmental document which has been adopted or certified, which described or evaluated regional or area wide conditions contributing to the cumulative impact.” (14 Cal. Code Regs., §15130(b)(1)(B)). This PSA uses the “list approach” for purposes of state law to provide a tangible understanding and context for analyzing the potential cumulative effects of the proposed project.

In order to provide a basis for cumulative analysis for each discipline, this section provides information on other projects in both maps and tables. All projects used in the Cumulative Impacts Analysis for this PSA are provided in cumulative projects tables. **Executive Summary – Cumulative Impacts Figure 1,** presented at the end of this section, shows projects within 50 miles of the SEP site. However, within the desert region, the specific area of cumulative effect varies by resource. For this reason, each discipline has identified the geographic scope for the discipline's analysis of cumulative impacts, which may exceed the 50-mile buffer shown in **Figure 1**.

APPROACH TO CUMULATIVE IMPACT ANALYSIS

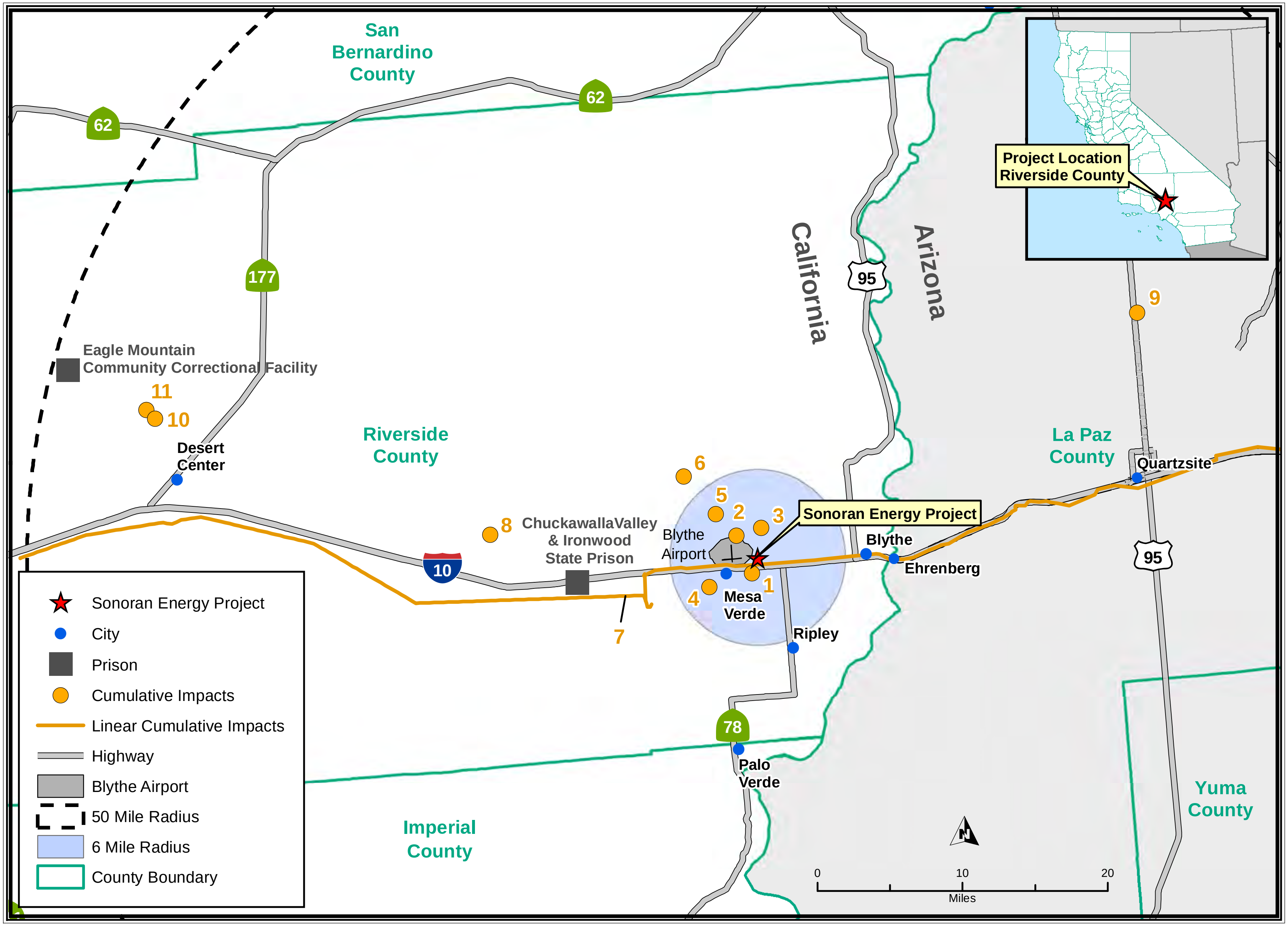
Staff developed the Sonoran Cumulative Project List by contacting the planning staff with the city of Blythe, Riverside County, and Bureau of Land Management Palm Springs-South Coast Field Office. Staff also reviewed proposed project information from other agencies including CalTrans and CEQAnet database.

Executive Summary Attachment A Table 1
Sonoran Energy Project – Cumulative Projects List

ID #	Project Title	Description	Location	Distance to Project (miles)	Status
1	Blythe Mesa Solar Power Project	485 MW solar photovoltaic facility and 8.4-mile generation interconnection line on 3,660 acres.	One mile north and south I-10 and three miles west Blythe	0.84	Approved
2	NRG Blythe II	20 MW photovoltaic solar facility.	North of I-10, south of 8th Ave, and west of Buck Blvd	2.13	In Construction
3	Palo Verde	486 MW solar photovoltaic solar facility.	North of 10th Ave, south of 5th Ave, west of Neighbors Blvd	2.34	Under Review
4	Desert Quartzite, LLC	300 MW solar photovoltaic facility on 5,003 acres of public and private land (4,843 acres of BLM-managed public land, and 160 acres of private land).	South of I-10, 8 miles southwest of Blythe	3.56	Pending
5	NextEra Blythe Solar Energy Center, LLC	485 MW solar plant site of 4,070 acres, convert the Approved Project's solar thermal generating technology to PV.	Two miles north of I-10 and eight miles west of Blythe	4.17	In Construction
6	Nextera Energy Resources, LLC - McCoy	Proposal to construct 750 MW photovoltaic solar facility.	13 miles northwest of Blythe	7.55	In Construction
7	Devers-Palo Verde No.2 Transmission	500kV electrical transmission line from the Colorado Substation located near Blythe to Devers Substation in Palm Springs, a distance of approximately 115 miles; and from Denver Substation to the Valley Substation in Romoland, Riverside County, a distance of 41.6 miles.	Devers Substation in Palm Springs to Palo Verde Nuclear Generating Station west of Phoenix, AZ	7.65	Approved
8	Genesis Solar, LLC - Genesis Solar	Two independent 125 MW solar electric generating facilities. Electrical power is produced using steam turbine generators fed from solar steam generators.	25 miles west Blythe	18.19	Operational as of 3/7/15
9	Quartzsite Solar Energy Project	100 MW solar-powered electrical generation facility with a 653 foot tower, receiver of energy reflected from solar fields of heliostats. Includes a thermal energy storage system.	10 miles north of Quartzsite and adjacent SR-95 in La Paz County, AZ	31.15	Approved
10	EDF Renewable Energy - Desert Harvest Solar	150 MW photovoltaic solar facility on 1,208 acres and generation-intertie transmission line.	Six miles north of Desert Center	42.17	Authorized
11	Desert Sunlight Holdings, LLC - Desert Sunlight	550 MW solar photovoltaic power plant with three main components 1) the Solar Farm site, 2) a transmission line, and 3) a Southern California Edison owned and operated substation, Red Bluff Substation.	Six miles north of Desert Center	42.90	Authorized - Notice to Proceed

CUMULATIVE IMPACTS - FIGURE 1

Sonoran Energy Project - Cumulative Projects Map



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: California Energy Commission, Open Street Map

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SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
INTRODUCTION
Mary Dyas

On August 7, 2015, AltaGas Sonoran Energy, Inc. (AltaGas) filed a petition with the Energy Commission requesting to modify the approved Blythe Energy Project Phase II (BEP II). The Petition to Amend (PTA) will be processed as an amendment to the approved BEP II 2005 Final Commission Decision (2005 Decision) that was certified by the California Energy Commission (Energy Commission) on December 14, 2005 and modified on April 26, 2012 (2012 Order). The first proposed modification is to change the name of the project from Blythe Energy Project Phase II to the Sonoran Energy Project (SEP). The project under this current PTA will be referred to as the SEP going forward in this document.

The SEP site is located within the city of Blythe, approximately five miles west of the city center, in eastern Riverside County.

AMENDMENT PROCESS

The purpose of the Energy Commission's amendment review process is to assess the impacts of the changes to the licensed project on environmental quality and public health and safety. The review process will also determine if the proposed modified project would remain in compliance with applicable laws, ordinances, regulations, and standards (LORS) (Cal. Code Regs., tit. 20, § 1769).

For an amendment to an existing power plant over which it has regulatory oversight, the Energy Commission is the lead state agency under the California Environmental Quality Act (CEQA). The Energy Commission's certified regulatory program provides the environmental analysis that satisfies CEQA requirements. In fulfilling this responsibility, Energy Commission staff provides an independent assessment of the amendment's engineering design, evaluates its potential effects on the environment and on public health and safety, and determines whether the project, if modified, would remain in conformance with the conditions of certification in the 2005 Decision and all applicable LORS. The analysis is guided by CEQA Guidelines Section 15162, which provides that no new environmental impact analysis is necessary unless:

1. Substantial changes are proposed in the project which will require major revisions of the previous Final Decision due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or
2. Substantial changes have occurred with respect to the circumstances under which the project is undertaken which will require major revisions of the previous Final Decision due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

3. New information of substantial importance which was not known, and could not have been known at the time of preparation of the previous Final Decision, shows:
   a. The project will have one or more significant effects not discussed in the previous Final Decision;
   b. Significant effects previously examined will be substantially more severe than shown in the previous Final Decision;
   c. Mitigation measures or alternatives previously found to be not feasible would now be feasible and would substantially reduce one or more significant effects of the project, but the project proponent declines to adopt the mitigation measure of alternative; or
   d. Mitigation measures or alternatives which are considerably different from those analyzed in the previous Final Decision would substantially reduce one or more significant effects on the environment, but the project proponent declines to adopt the mitigation measure or alternative.

Where supplementation is necessary, Energy Commission staff's assessment provides a summary of the substantial changes or new information and an analysis of the resulting new or increased significant effects and new or newly-feasible mitigation measures or alternatives. Where necessary, staff recommends any needed modifications to existing conditions of certification in the Final Decision and proposes additional conditions of certification for the revised Final Decision to mitigate any significant adverse environmental effects of the proposed modifications.

The Energy Commission Committee assigned to this PTA has determined that this amendment will follow the siting review process in order to afford agencies, interested parties, intervenors, and the public, the greatest opportunity for participation and review of the proposed project.

PURPOSE OF THIS REPORT

This Preliminary Staff Assessment (PSA) is being published by the Energy Commission and is staff's independent analysis of the petition to amend the BEP II. This PSA is a staff document. It is neither a Committee document, nor a draft Decision. The PSA describes the following:

- the proposed modified project (SEP);
- the updated existing environment from the existing site;
- whether the modified facilities can be constructed and operated safely and reliably in accordance with applicable LORS;
- the potential direct, indirect, and cumulative impacts of the modified project;

- modified and/or new conditions of certification proposed by the project owner, staff, interested agencies, local organizations, tribes, and intervenors which may lessen or eliminate potentially significant adverse impacts of the modified project; and

- project alternatives.

The analyses contained in this PSA are based upon information from the: 1) Petition to Amend and Supplements to the Petition to Amend provided by the project owner; 2) responses to Energy Commission staff data requests; 3) supplementary information from local, state, and federal agencies, interested organizations and individuals; 4) existing documents and publications including the record from the approved BEP II; 5) independent research; 6) comments at public workshops; and 7) other docketed communications. The analyses for most technical areas include discussions of proposed modifications to conditions of certification and new, additional, conditions of certification. Each condition of certification is followed by a proposed means of verification. All changes to conditions of certification in the original decision are shown in this document so the reader can easily identify the changes being made to the project license. Deleted text to the conditions of certification is shown as ~~strikethrough~~, new text is **<u>bold and underlined</u>**.

The PSA presents preliminary conclusions about potential environmental impacts and conformity with LORS of the modified project, as well as modified and/or new conditions that apply to the design, construction, operation and closure of the facility.

This document is intended to be a complete review of the modified project and in many cases relies on analysis that was prepared during the licensing process for the approved BEP II project, and the approved 2009 petition to amend (2012 Order), as baseline information. This information has been reviewed and updated to reflect current conditions and the setting that exists today.

ORGANIZATION OF THE PRELIMINARY STAFF ASSESSMENT

The sections in this PSA include an Executive Summary, Introduction, Project Description, and a Project Analysis. The Project Analysis contains an Environmental Assessment, Engineering Assessment, Alternatives and General Conditions of Certification. The Environmental Assessment contains the following chapters: 1) Air Quality; 2) Biological Resources; 3) Cultural Resources; 4) Hazardous Materials Management; 5) Land Use; 6) Noise and Vibration; 7) Public Health, 8) Socioeconomics; 9) Soil and Water Resources; 10) Traffic and Transportation; 11) Transmission Line Safety and Nuisance; 12) Visual Resources; 13) Waste Management; and 14) Worker Safety and Fire Protection. The Engineering Assessment contains the following sections: 15) Facility Design; 16) Geology and Paleontology; 17) Power Plant Efficiency; 18) Power Plant Reliability; and 19) Transmission System Engineering. The Environmental Assessment, Engineering Assessment, and General Conditions of Certification are followed by a discussion of facility closure, project construction and operation, compliance monitoring plans, and a list of staff that assisted in preparing this report.

All of the sections under the Environmental Assessment, Engineering Assessment, and the General Conditions of Certification include a: Summary of Conclusions; Introduction; Summary of Decision; discussion of LORS; an environmental impact analysis; conclusions and recommendations; and modified and/or new conditions of certification for both construction and operation (if applicable).

ENERGY COMMISSION REVIEW PROCESS

The Energy Commission has the exclusive authority to certify the construction and operation of thermal electric power plants 50 megawatts (MW) or larger. The Energy Commission certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, §25500).

The Energy Commission's regulations require staff to independently review the PTA and assess whether the list of environmental impacts it contains 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 is presented in this report (Cal. Code Regs., tit. 20, §1742.5). In addition, staff must assess the completeness and adequacy of the health and safety standards, and the reliability of power plant operations (Cal. Code Regs., tit. 20, § 1743(b)). Staff is required to coordinate with other agencies to ensure that applicable LORS are met (Cal. Code Regs., tit. 20, § 1744(b)).

Staff conducts its environmental analysis through a California Environmental Quality Act (CEQA) equivalent process, thus no Environmental Impact Report (EIR) is required because the Energy Commission's site certification program has been certified by the Secretary of the Natural Resources Agency (Pub. Resources Code, §21080.5 and Cal. Code Regs., tit. 14, §15251 (k)). The Energy Commission is the CEQA lead agency and is subject to all portions of CEQA applicable to certified regulatory activities.

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

Staff will provide a public comment period that follows the publication of the PSA. The comment period is also used to resolve issues between the parties and to narrow the scope of adjudicated issues in the evidentiary hearings. During this time, staff will conduct one or more workshops to discuss its conclusions, proposed mitigation, and proposed verification measures. Based on the workshop dialogue and any written comments received, staff may refine its analysis, correct any errors, and finalize conditions of certification to reflect any changes agreed to between the parties. These revisions and changes will be presented in a Final Staff Assessment (FSA) that will be published and made available to the public and all interested parties.

The FSA is only one piece of evidence that will be considered by the Committee (two Energy Commission 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 evidentiary hearings, all parties will be afforded an opportunity to present evidence, thereby creating a hearing record on which a decision on the project can be based. The hearing before the Committee also allows all parties to argue their positions on disputed matters, if any, and it provides a forum for the Committee to receive comments from the public and other governmental agencies.

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

A Compliance Monitoring Plan and General Conditions of Certification will be assembled from conditions contained in the Final Decision. The Energy Commission staff's implementation of the plan ensures that a certified facility is constructed, operated, and closed, in compliance with the conditions of certification adopted by the Energy Commission.

PUBLIC AND AGENCY COORDINATION

The Energy Commission amendment process includes a schedule that provides public comment and participation opportunities along with staff technical review and analysis. The Energy Commission seeks comments from, and works closely with, other regulatory agencies that administer LORS that may be applicable to the proposed project.

During the review process of the amendment, staff coordination will include numerous local, state and federal agencies that have an interest in the project. Particularly, Energy Commission staff will be working with the City of Blythe, Mojave Desert Air Quality Management District; California Independent System Operator (California ISO); California Air Resources Board; Riverside County Airport Land Use Commission; California Department of Fish and Wildlife; U.S. Environmental Protection Agency; U.S. Fish and Wildlife Service; U.S. Army Corp of Engineers; and the Federal Aviation Administration to identify and resolve issues of concern.

Staff anticipates several public events that include: workshops on the PSA, evidentiary hearings, and a public hearing for the Commission Decision by a vote at a Commission

Business Meeting. Public agencies and interested parties will be active participants in this process.

OUTREACH EFFORTS

Energy Commission staff sent notices regarding receipt of the PTA and Commission events and reports related to the proposed project interested persons, including all property owners within 1,000 feet of a project and 500 feet of a linear facility (such as transmission lines, gas lines and water lines). Notices have also been provided to local libraries, adjacent cities and counties, Native American communities, local elected representatives and other interested parties.

On August 24, 2015, a Notice of Receipt for the SEP PTA was mailed to the post certification mailing list along with updated interested parties. The Hearing Officer sent a public notice to appropriate parties on September 11, 2015, for a September 28, 2015, Public Site Visit, Environmental Scoping Meeting and Informational Hearing. Staff's ongoing public and agency coordination activities for this project are discussed under the Public and Agency Coordination heading in the **Executive Summary** section of the PSA.

The Energy Commission's outreach efforts are an ongoing process that, to date, has involved the following efforts:

LIBRARIES

On August 24, 2015, the Energy Commission staff sent the Notice of Receipt to various libraries within the project vicinity including Brawley Public Library, Parker Arizona Public Library, and Riverside Library - Main Branch.

In addition, to these local libraries, copies of the Petition to Amend are also available at the Energy Commission's Library in Sacramento, the California State Library in Sacramento, as well as the public libraries in Eureka, Fresno, Los Angeles, San Diego, and San Francisco.

NOTIFICATION TO NATIVE AMERICAN COMMUNITIES

The Energy Commission Cultural Recourses staff contacted the Native American Heritage Commission (NAHC) on September 16, 2015 to conduct a search of the Sacred Lands File (SLF) and to determine the appropriate tribes that may be affiliated with the SEP. The NAHC response did not arrive as expeditiously as anticipated, and therefore staff sent letters on September 30, 2015 to the sixteen tribal governments with whom staff typically consults on projects in the Palo Verde Mesa area, informing them of project details and offering to consult with them regarding the SEP amendment. The NAHC responded on October 7, 2015 that the search of the SLF was negative, and included five groups on the contact list, all of whom were included in the staff September 30, 2015 mailing. Staff followed up letters with phone calls and emails in early October 2015. These Native American communities included: Augustine Band of

Cahuilla Indians, Agua Caliente Band of Cahuilla Indians, San Manuel Band of Mission Indians, Cabazon Band of Mission Indians, Cahuilla Band of Mission Indians, Chemehuevi Indian Tribe, Cocopah Indian Tribe, Colorado River Indian Tribes, Fort Mojave Indian Tribe, Morongo Band of Mission Indians, Quechan Indian Tribe, Fort Yuma Indian Reservation, Ramona Band of Cahuilla, Santa Rosa Band of Cahuilla Indians, Soboba Band of Luiseno Indians, Torres-Martinez Desert Cahuilla Indians, and Twenty-Nine Palms Band of Mission Indians.

PUBLIC ADVISER'S OFFICE

The public adviser helps the public participate in the Energy Commission's hearings and meetings. The Public Adviser assists the public by advising them how they can participate in the Energy Commission process; however, the office does not represent members of the public.

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.

California law defines environmental justice as "the fair treatment of people of all races, cultures and income with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies" (Gov. Code, § 65040.12; Pub. Resources Code, § 72000). The California Natural Resources Agency environmental justice policy directs all departments, boards, commissions, conservancies and special programs of the Resources Agency to consider environmental justice in their decision-making process if their actions have an impact on the environment, environmental laws, or policies.

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 a minority or low-income population exists within the potentially affected area of the proposed site.

Staff's specific activities with respect to environmental justice for the SEP amendment are discussed in the **Executive Summary**.

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SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
PROJECT DESCRIPTION
Mary Dyas

INTRODUCTION

On August 7, 2015, AltaGas Sonoran Energy, Inc. (AltaGas) filed a petition with the Energy Commission requesting to modify the approved Blythe Energy Project Phase II (BEP II). The Petition to Amend (PTA) will be processed as an amendment to the approved BEP II Final Commission Decision (Final Decision) that was certified by the California Energy Commission (Energy Commission) on December 14, 2005 and modified on April 26, 2012. The first proposed modification is to change the name of the project from Blythe Energy Project Phase II to the Sonoran Energy Project (SEP). The project under this current PTA will be referred to as the SEP going forward in this document.

PROJECT LOCATION AND SITE DESCRIPTION

The SEP site is located within the city of Blythe, approximately five miles west of the city center, in eastern Riverside County. **Project Description Figure 1** provides a map of the regional setting. **Project Description Figure 2** provides an aerial photo of the existing Blythe Energy Project (BEP) and SEP sites and their immediate vicinity.

The project site is located approximately one mile east of the Blythe Airport, which is currently owned by Riverside County. **Project Description Figure 3** provides a site map showing the BEP and the approved BEP II site in relation to the airport. 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 site slopes from an elevation of 350 feet in the northern portion of the parcel to 340 feet in the southern portion. The site is bound to the north by Riverside Avenue, to the east by the existing BEP, and to the south by Hobsonway. The site is fenced, sparsely vegetated, and relatively flat.

The SEP site boundary is located on an approximately 76-acre, previously disturbed site, immediately adjacent to the operational BEP which is owned by Blythe Energy Inc. and operated by AltaGas Blythe Operations Inc. The SEP site boundary is the same as the BEP II; although the project layout of the SEP is different than the BEP II layout. **Project Description Figures 4a** and **4b** show the differences in the layout of the BEP II and the SEP and the site related to the existing BEP.

The SEP would be built within the same site as the licensed and previously amended footprint, with the exception of a portion of the proposed interconnection gen-tie line that crosses the unpaved W. Chanslor Way (adjacent to the northern SEP boundary) and extending east parallel to W. Chanslor Way for approximately 900 feet before entering the Buck Boulevard substation. This area has been surveyed for biological resources, cultural resources and paleontological resources.

BACKGROUND OVERVIEW

2005 ORIGINAL APPROVED PROJECT

On December 14, 2005, the Energy Commission granted a license to Caithness Blythe II, LLC, to construct the nominal 520 megawatt (MW) combined-cycle BEP II. The BEP II would consist of:

- An electrical interconnection to the Buck Boulevard Substation, located in the northeastern corner of the existing Blythe Energy Project (99-AFC-8C) site;
- Two Siemens Westinghouse V84.3a 170 MW combustion turbine generators (CTG);
- One 180 MW steam turbine generator (STG); and
- Supporting equipment.

Wastewater would be treated and recycled with a Zero Liquid Discharge (ZLD) system to reduce total water consumption. No effluent is disposed off-site from the facility under normal conditions. Industrial waste water discharge to the storm water retention ponds is allowed when the ZLD is off-line. A liquid wastewater discharge either on or off-site is prohibited, with the exception of the temporary discharge of wastewater to evaporation ponds during periods of ZLD system outages permitted by the Regional Water Quality Control Board via the issuance of Waste Discharge Requirements.

2009 APPROVED AMENDMENT

On April 26, 2012, an amendment to the license was approved by the Energy Commission. The modified BEP II would be a nominal 569 MW combined-cycle facility. The changes included the following:

- A new point of electrical interconnection via a 2,100 foot-long 500 kilovolt (kV) transmission line into the proposed Keim substation;
- Replacement of the Siemens Westinghouse V84.3a turbines with fast-start Siemens SGT6-5000F turbines;
- Modification of the combustion turbine and steam turbine enclosure;
- Incorporation of an auxiliary boiler to allow fast start technology;
- Increase in size of cooling tower by 1,020 square feet; and
- Optimization of the General Arrangement.

Concurrently, in April 2012, a five-year extension of the Deadline for the Start of Construction, from December 14, 2011 to December 14, 2016, was approved. Unless noted, other areas and conditions of certification remained as published in the 2005 Decision.

2014 APPROVED OWNERSHIP CHANGE

Ownership of the project changed in 2014, from Caithness Blythe II, LLC to AltaGas Sonoran Energy Inc.

2015 PROPOSED PROJECT MODIFICATIONS OVERVIEW

As previously noted, on August 7, 2015, AltaGas filed a petition with the Energy Commission requesting to modify the approved BEP II and change the name of the project to the Sonoran Energy Project. Other modifications proposed for the project include the following:

- Define a new point of electrical interconnection via a 1,320-foot, 161-kV transmission line to the Western Area Power Administration's Blythe substation located southeast of the project site via an existing transmission line located in the Southern California Edison (SCE) Buck Boulevard substation;
- Replace the two Siemens SGT6-5000F combustion turbines with a single, more efficient General Electric (GE) Frame 7HA.02 combustion turbine;
- Replace the Siemens steam turbine generator (STG) with a more efficient single-shaft GE D652 STG;
- Increase the size of the auxiliary boiler to support the CTG's rapid response fast start capability;
- Decrease the size of cooling tower from an 11-cell to a 10-cell tower in response to the reduced heat rejection requirements;
- Decrease the size of the emergency diesel fire pump engine; and
- Optimize the general arrangement.

The PTA proposes that wastewater be disposed in onsite evaporation ponds, which have been sized to meet the demands of the proposed project modification, and will be smaller than the evaporation ponds associated with the licensed project. The PTA addresses the ZLD and limited use of the ponds as required by Conditions of Certification **WATER QUALITY-5** and **BIO-12** in the 2005 Decision.

SONORAN ENERGY PROJECT OVERVIEW

The proposed SEP would be a natural gas-fired, water-cooled, combined-cycle, 553 MW net electrical generating facility, laid out using one-on-one single shaft arrangement utilizing a GE 7HA.02 gas turbine and a D652 steam turbine. The power block would consist of one natural gas-fired CTG, one supplemental-fired heat recovery steam generator (HRSG), one STG, an induced-draft cooling tower, and related ancillary equipment. Other equipment and facilities to be constructed are an auxiliary boiler, water treatment facilities, emergency services, and administration and maintenance buildings. The project site is the same as previously licensed for BEP II in 2005 and amended in 2012.

The SEP would share some facilities with the existing BEP, including an existing 16-inch natural gas line located on the south side of the BEP property boundary. The gas line would be extended north to a new SEP conditioning and regulating station.

The interconnection is an approximately 1,320-foot, 161-kV transmission line from SEP to the existing Western Area Power Administration's Blythe substation. The Blythe substation is located on a separate parcel southeast of the SEP site. The proposed modifications would be performed within the same footprint as the licensed and modified BEP II with the exception of a portion of the proposed interconnection gen-tie line that crosses the unpaved road (adjacent to the northern SEP boundary), turns east to the western corner of the Buck Boulevard substation.

The auxiliary steam boiler would provide steam during gas turbine start-up and shutdown to allow startups and shutdowns to be accomplished more quickly. The boiler would provide up to 60,000 pounds per hour of steam to warming the steam turbine, maintaining vacuum on the steam condenser, and heating/reheating condensate.

Primary access to the SEP site would be provided via the north entrance off Riverside Avenue. The existing BEP entrance would be connected to the SEP entrance via a new access road. A secondary SEP access road would be off Hobsonway.

WATER SUPPLY, TREATMENT, AND WASTEWATER DISCHARGE

Construction water would be groundwater from either the new onsite wells (when completed) or the existing BEP water supply system. During construction, the average daily water use is expected to be approximately 20,000 gallons. During the commissioning period, when activities such as hydrostatic testing, cleaning and flushing, and steam blows of the HRSG and steam cycles would be conducted, average water usage is estimated at 30,000 gallons per day with a maximum daily use of 643,080 gallons. Hydrostatic test water and cleaning water would be tested and disposed in accordance with applicable laws, ordinances, regulations and standards.

Operation of the SEP would not exceed a maximum of 2,800 acre-feet per year of water, based on the facility operating 7,000 hours per year.

Water for sanitary purposes would either be bottled water or provided by BEP's potable water system. Portable toilets would be provided throughout the site. Sanitary wastewater discharge from the SEP would be sent to a new onsite septic system with a leach field.

Degraded (brackish) well water would be used directly as cooling tower makeup water and would feed the onsite service and potable water treatment system.

The primary source of fire protection water for the project would be from a new raw water storage tank and emergency diesel fire pump engine. The water supplying the tank would be from wells located on the western side of the project site.

The wastewater treatment system uses a lime softening system, a cation exchange system, and an RO system to treat/recycle water. The discharge from this system will be stored in a treated wastewater tank. The waste generated by the lime softening system will be directed to a filter press system and the solids will be disposed of as nonhazardous waste similar to the licensed project. The effluent from the RO system will be directed to a brine concentrator. Water produced from brine concentrating will be sent to the treated wastewater tank. The concentrated brine is proposed to be disposed of in the onsite evaporation ponds.

Any water that is not adequately treated for reuse will be discharged to one of two new evaporation ponds for ultimate disposal through evaporation. The evaporation ponds will be designed with high density polyethylene liners and sufficient surface area to evaporate rainwater that falls directly in the pond as well as water discharged from the brine concentrator.

TRANSMISSION SYSTEM ENGINEERING

The interconnection is an approximately 1,320-foot, 161-kV Gen-Tie line from SEP to the existing Western Area Power Administration's (WAPA) Blythe substation. The Blythe substation is located on a separate parcel southeast of the SEP site.

As proposed in the PTA, the SEP would interconnect to the 161-kV Buck Boulevard substation. The interconnection route extends north from the SEP generator step-up unit transformer, exiting the SEP site at the northern boundary. The gen-tie line crosses the unpaved road (adjacent to the northern SEP boundary) and enters private property (owned by the corporate parent of the project owner). The line then turns east to the western corner of the Buck Boulevard 161-kV substation, and then turns south to the 161-kV Blythe substation, via an existing 161-kV Buck Blvd-Blythe transmission line. The 150-foot wide right-of-way would traverse public (the adjacent public road) and private (property owned by the corporate parent of the project owner and WAPA) lands.

CONSTRUCTION AND OPERATIONAL WORKFORCE

For the original licensed project, the construction workforce was noted at 387 peak workers with an average between 200 to 300 workers. The operational workforce was approximately 20 permanent workers to maintain and operate the project (12 to 14 operating technicians, 3 to 4 maintenance technicians and 3 to 4 administrators).

The changes approved in 2012 were not expected to increase or diminish the construction workforce or number of permanent workers previously approved.

Under the current proposed changes, construction personnel requirements would peak at approximately 325 workers in month 12 of the construction period instead of 387 in month 12 as previously analyzed during project licensing. During operation, the SEP would be operated from the BEP control room. As such, the incremental increase in operational staffing for SEP is expected to be 9 employees, including 5 plant operators, 1 administrative person, 2 mechanics, and 1 plant engineer, in three rotating shifts. The facility would be capable of operating 24 hours per day, 7 days per week.

FACILITY CLOSURE

The planned operating life of the SEP is 30 years or longer if still economically viable. It is also possible that the facility could become economically noncompetitive in less than 30 years, forcing early decommissioning. Whenever the facility ceases operation and is permanently closed, it would be necessary to ensure that the closure occurs in a manner that protects public health and safety and the environment from adverse effects. Provisions must be made that provide the flexibility to deal with the specific situation and project setting that exist at the time of closure. Facility closure would be consistent with LORS in effect at the time of closure.

The decommissioning plan for the facility would attempt to maximize the recycling of all facility components. If possible, unused chemicals will be sold back to the suppliers or other purchasers or users. All equipment containing chemicals will be drained and shut down to ensure public health and safety and to protect the environment. All nonhazardous wastes will be collected and disposed of in appropriate landfills or waste collection facilities. All hazardous wastes will be disposed of according to all applicable LORS. The site will be secured 24 hours per day during decommissioning activities.

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

ASE2015b. AltaGas Sonoran Energy Inc. Permit Application for Mojave Desert Air Quality Management District for Project Modifications (TN 205687). Docketed on 8/11/2015.

ASE2015c. AltaGas Sonoran Energy Inc. Data Responses Set 1 (Responses to Data Requests 1 to 58) (TN 206606). Docketed on 11/12/2015.

CBE2002a. Caithness Blythe Energy, Inc. Application for Certification (AFC), Vol. 1 & Vol. 2. (TN 24604). Docketed on 02/19/2002.

CBE2002b. Caithness Blythe Energy, Inc. Revised Application for Certification for Blythe II. (TN 26100) Docketed on 07/03/2002.

CBE2009a. Caithness Blythe Energy, Inc. Phase II Amendment (TN 53798). Docketed on 10/26/2009.

CBE2010a. Caithness Blythe Energy, Inc. Supplement #1 to Amendment (TN 55438). Docketed on 2/16/2010.

CBE2011a. Caithness Blythe Energy, Inc. Blythe II Amendment Supplement #3 (TN 62479). Docketed 10/4/2011.

CBE2011b. Caithness Blythe Energy, Inc. 2009 Petition to Amend Supplement #2 (TN 63093). Docketed on 12/9/2011.

CEC2012a. California Energy Commission. Petition to Amend – Staff Analysis (TN 60499). Docketed on 3/12/2012.

CEC2012b. California Energy Commission. Commission Order Approving Petition to Amend (TN 64945). Docketed on 4/26/2012.

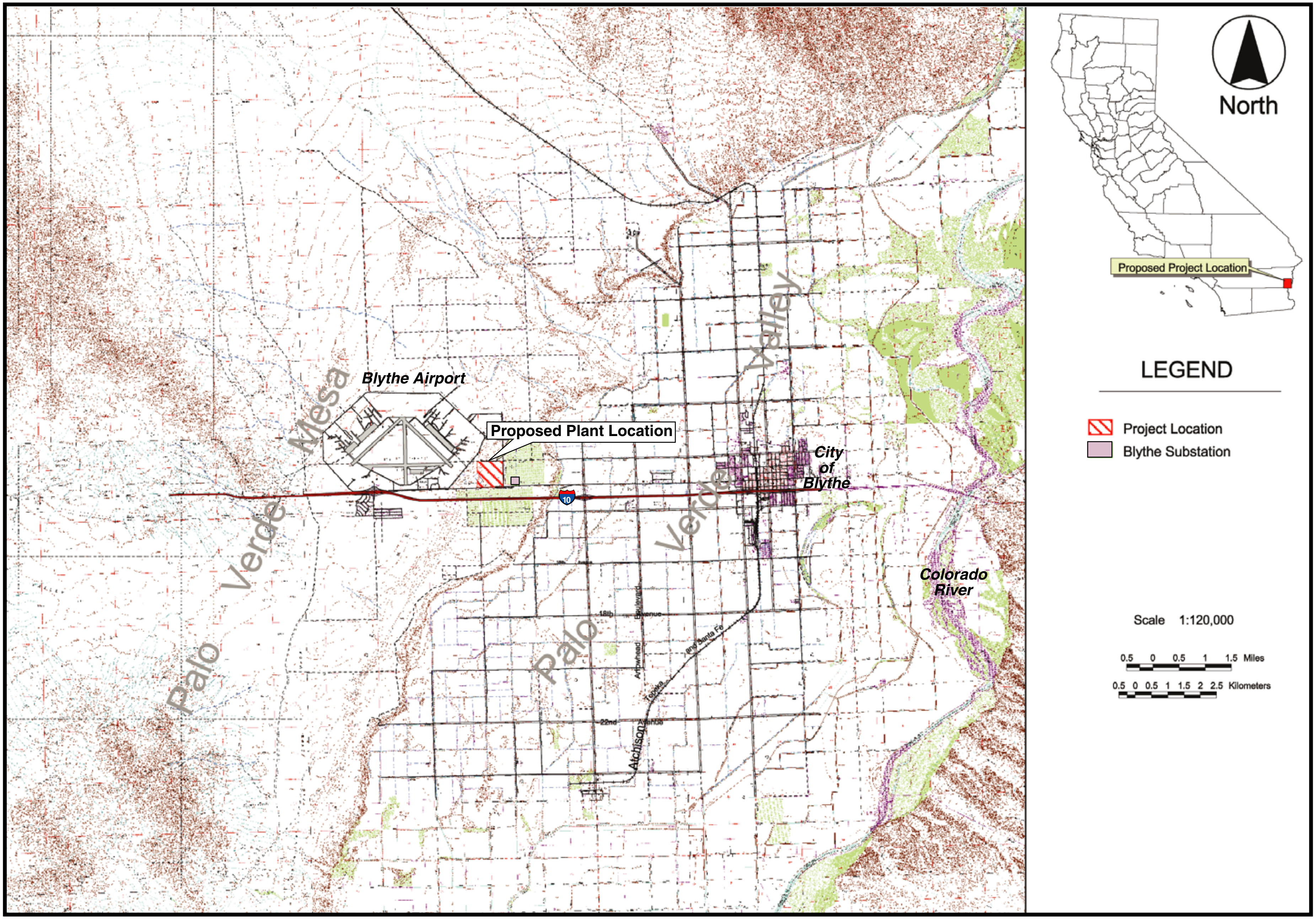
CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2015a. California Energy Commission. Notice of Receipt (TN 205798). Docketed on 8/24/2015.

CEC2015b. California Energy Commission. Data Requests Set No. 1 (1-58) (TN 206331). Docketed on 10/12/2015.

PROJECT DESCRIPTION - FIGURE 1

Sonoran Energy Project - Regional Location of Proposed Project



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: AFC Figure 2.0-1

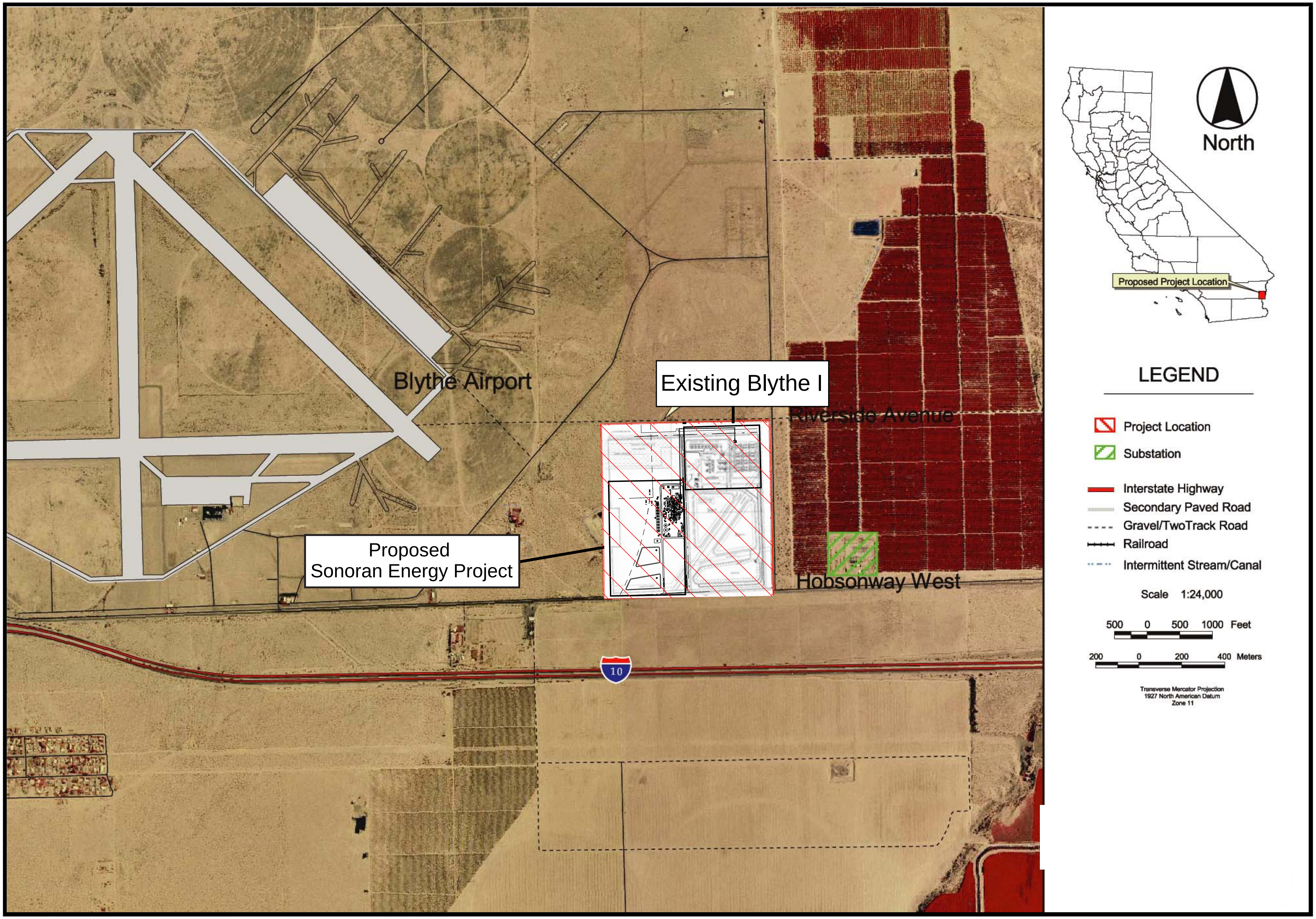
PROJECT DESCRIPTION - FIGURE 2

Sonoran Energy Project - Site Vicinity Map of Proposed Project

SOURCE: Sonoran Energy Project - 2015 Petition to Amend Figure 2-1

PROJECT DESCRIPTION - FIGURE 3

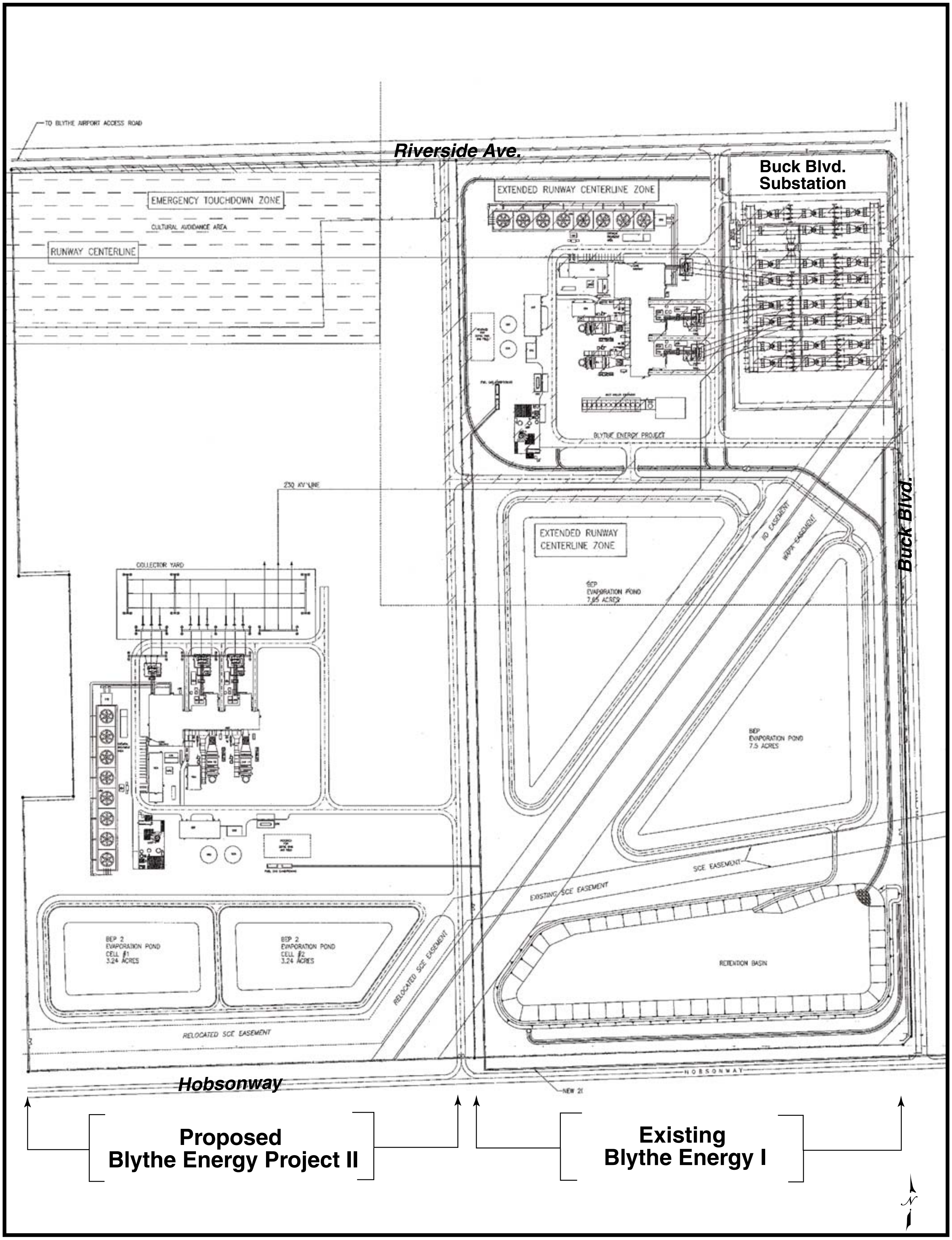
Sonoran Energy Project - Project Site Map



SOURCE: AFC Figure 2.0.3

PROJECT DESCRIPTION - FIGURE 4a

Blythe Energy Project II - Site Plan / Layout

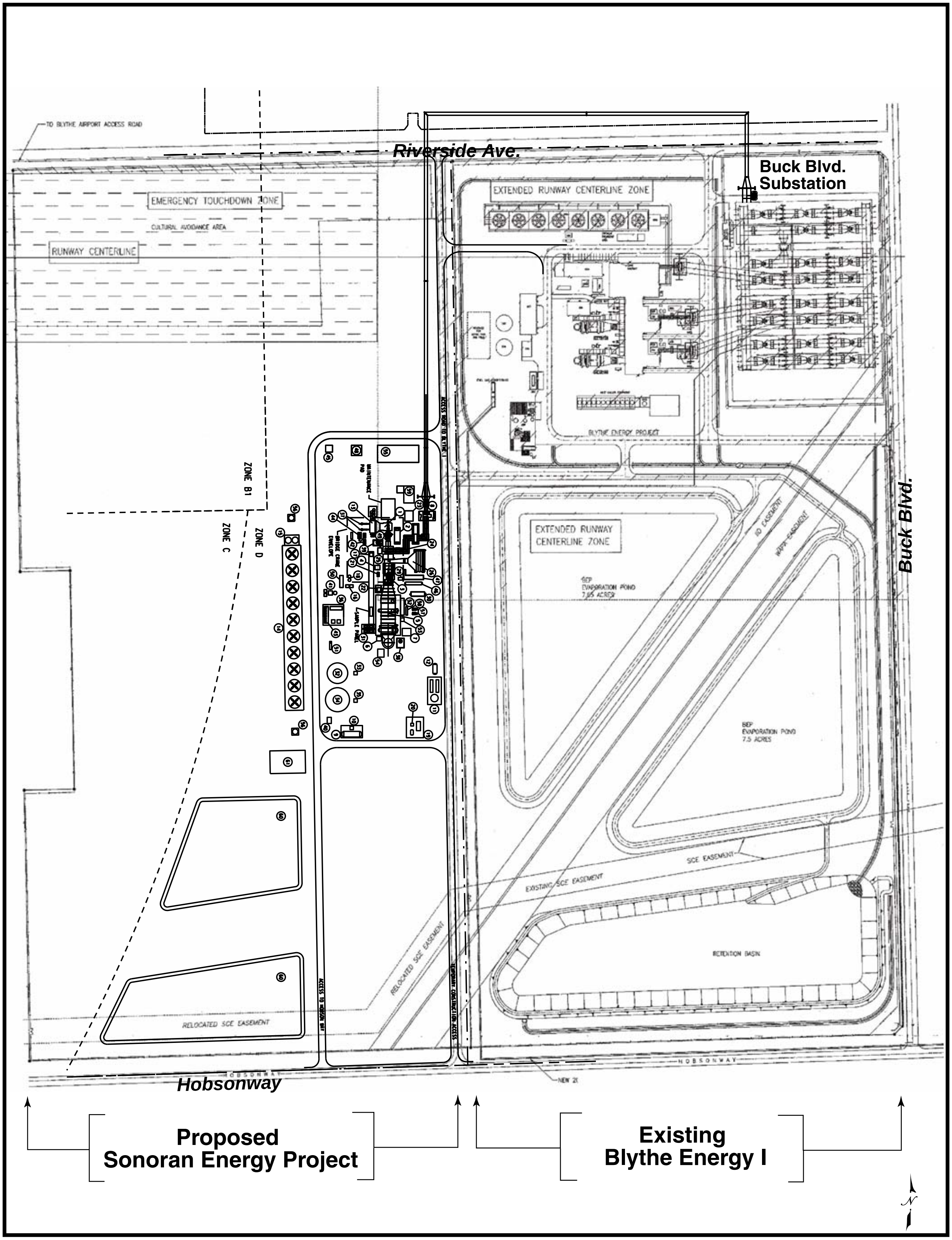


CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION

SOURCE: AFC Figure 36-1

PROJECT DESCRIPTION - FIGURE 4b

Sonoran Energy Project - Site Plan / Layout



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION

SOURCE: BEP II AFC Figure 36-1 AND SEP PTA Figures 2-2a and 2-2b

ENVIRONMENTAL ASSESSMENT

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SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
AIR QUALITLY
Tao Jiang, Ph.D., P.E.

SUMMARY OF CONCLUSIONS

In this Petition to Amend (PTA) the Sonoran Energy Project (SEP), formally Blythe Energy Project II (BEP II) proposes to modify the project which will necessitate modification to existing **Air Quality** Conditions of Certification. Staff concludes that with the adoption of the attached conditions of certification, the proposed SEP would not result in significant air quality related impacts during project construction and operation, and that the SEP would comply with all applicable federal, state and Mojave Desert Air Quality Management District (MDAQMD or District) air quality laws, ordinances, regulations, and standards (LORS). Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that a supplementation to the 2005 BEP II Commission Decision (2005 Decision) and 2012 Commission Order (2012 Order) is necessary for **Air Quality**. The Committee should re-analyze the conclusions of the 2005 Decision and 2012 Order alongside this new information.

If the project design includes an air cooled condenser (ACC or “dry cooling”) instead of a wet cooling tower, criteria air pollutants from the cooling tower would be avoided. But emissions from the combustion turbine and HRSG might increase or decrease, depending on how the project owner sizes the ACC and incorporates the ACC into the project design and operations. Staff does not see any fatal flaws in the area of AQ in incorporating an ACC into the SEP project design.

INTRODUCTION

The California Energy Commission (CEC) received an amendment request for the SEP from AltaGas Sonoran Energy Inc. on August 7, 2015. The BEP II project has not yet begun construction since its original certification. It would be located within the City of Blythe, in eastern Riverside County. The SEP would be located on a 76 acre site immediately adjacent to the operational Blythe Energy Project (BEP).

AltaGas Sonoran Energy Inc. proposes two changes to the BEPII license. The first proposed change is to change the name from BEPII to SEP in order to reduce the potential confusion associated with the number of generating projects in the area using the name “Blythe”. The second proposed change involves the following:

- Define a new point of electrical interconnection;
- Replace the two Siemens SGT6-5000F combustion turbines with a single, more efficient General Electric (GE) Frame 7HA.02 combustion turbine;

- Replace the Siemens Steam Turbine Generator (STG) with a more efficient GE D652 STG, on a single-shaft with the combustion turbine;
- Increase the size of the auxiliary boiler to support GE's rapid response fast start capability;
- Decrease the size of cooling tower from an 11-cell to a 10-cell tower in response to the reduced heat rejection requirements; and
- Decrease the size of the emergency diesel fire pump engine.

In this analysis, staff evaluated the expected air quality impacts from construction and operation of the modified SEP. The following major points were evaluated:

- Whether SEP is likely to conform with applicable federal, state and MDAQMD air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- Whether SEP is likely to cause significant air quality impacts, including new violations of ambient air quality standards, or make substantial contributions to existing violations of those standards (Title 20, California Code of Regulations, section 1743); and
- Whether the mitigation measures proposed for SEP are adequate to lessen the potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 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 compounds (ROCs), and particulate matter less than ten microns in diameter (PM10) and less than 2.5 microns in diameter (PM2.5).

SUMMARY OF THE DECISION

BEP II was originally certified by the Energy Commission on December 14, 2005 (02-AFC-1) as a nominally rated 520-megawatt (MW) combined cycle facility with a maximum output of 538 MWs. On April 25, 2012, the Energy Commission approved a Petition to Amend the Commission Decision (2012 Order), including replacement of the Siemens Westinghouse V84.3a turbines with Siemens SGT6-5000F turbines, a new auxiliary boiler, a new point of electrical interconnection and optimization of the general facility arrangement.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The proposed SEP is subject to all the LORS described in the Final Staff Assessment (FSA) (CEC 2005a) for BEP II and previous staff analysis of proposed modifications (CEC 2012a). The analysis of this amendment would not change any LORS.

EXISTING AIR QUALITY

The project would be located in the Riverside County portion of the Mojave Desert Air Basin (MDAB) and would be under the jurisdiction of the MDAQMD. The Riverside County portion of the MDAB is designated as non-attainment for the state ozone and PM10 standards. This area is designated as attainment or unclassified for all federal criteria pollutant ambient air quality standards and the state CO, NO_2, SO_2, and PM2.5 standards. **Air Quality Table 1** summarizes the project site area's attainment status for various applicable state and federal standards.

Air Quality Table 1
Attainment Status of Mojave Desert Air Basin

Pollutant	Attainment Status	
	Federal	State
Ozone	Unclassified/Attainment	Nonattainment
CO	Unclassified/Attainment	Unclassified
NO_2	Unclassified/Attainment	Attainment
SO_2	Unclassified/Attainment	Attainment
PM10	Unclassified	Nonattainment
PM2.5	Unclassified/Attainment	Unclassified

Source: ARB 2016a, U.S.EPA 2016a.

Ambient air quality monitoring data for ozone, PM10, PM2.5, CO, NO_2, and SO_2, compared to most restrictive applicable standards for the years between 2009 through 2014 at the most representative monitoring stations for each pollutant are shown in **Air Quality Table 2**. Ozone data are from the Blythe-445 West Murphy Street monitoring station, located 5 ½ miles east of the facility location; PM10, PM2.5, NO_2, and CO data are from the Palm Springs-Fire Station monitoring station, located 107 miles west of the facility location and SO_2 data are from Riverside-Rubidoux monitoring station. These monitoring data can be expected to represent air quality levels at the project site or are higher in value than what would be monitored at the project site, meaning that the values conservatively represent air quality conditions at the site.

Air Quality Table 2
Maximum Ambient Concentrations (ppm or μg/m³)

Pollutant	Averaging Period	Units	2010	2011	2012	2013	2014
Ozone	1 hour	ppm	0.072	0.073	0.084	0.065	0.093
Ozone	8 hours	ppm	0.068	0.068	0.077	0.061	0.084
PM10[a]	24 hours	μg/m³	144	85	117	111	114
PM10	Annual	μg/m³	18.3	18.1	16.1	22.1	-
PM2.5	24 hours	μg/m³	12.6	12.5	13.7	13.8	14.5
PM2.5	Annual	μg/m³	5.9	6.0	6.4	6.5	6.4
CO	1 hour	ppm	1.6	3.0	0.9	3.2	2.2
CO	8 hours	ppm	0.5	0.6	0.5	1.5	0.9
NO_2	1 hour	ppm	0.046	0.044	0.045	0.052	0.046
NO_2	Federal 1 hour (98th Percentile)	ppm	0.039	0.039	0.039	0.039	0.041
NO_2	Annual	ppm	0.008	0.008	0.007	0.007	0.007
SO_2	1 hour	ppm	0.018	0.008	0.005	0.008	0.006
SO_2	Federal 1 hour (99th Percentile)	ppm	0.010	0.004	0.002	0.005	0.004
SO_2	24 hours	ppm	0.005	0.001	0.001	0.001	0.001

Source: ARB 2016b, U.S.EPA 2016b
[a] Exceptional PM concentration events excluded.

Staff recommends the background ambient air concentrations in **Air Quality Table 3** for use in the amendment impact analysis. The recommended background concentrations are based on the maximum criteria pollutant concentrations from the past three years of available data collected at the most representative monitoring stations surrounding the facility site. Data in **bold** represent the values above the applicable limiting standards.

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

Pollutant	Averaging Time	Background	Limiting Standard	Percent of Standard
PM10	24 hour	**117**	50	**234**
	Annual	**22.1**	20	**111**
PM2.5	24 hour	14.5	35	41
	Annual	6.5	12	54
CO	1 hour	3,680	23,000	16
	8 hour	1,667	10,000	17
NO_2	State 1 hour	97.8	339	29
	Federal 1 hour	77.1	188	41
	Annual	13.3	57	23
SO_2	1 hour	20.9	655	3
	Federal 1 hour	13.1	196	7
	24 hour	2.6	105	2

Source: ARB 2016b, EPA 2016b and independent staff analysis.

PROJECT DESCRIPTION AND EMISSIONS

The proposed SEP combined cycle power plant would consist of one GE 7HA.02 gas turbine, one heat recovery steam generator (HRSG) with duct burners, one auxiliary boiler and a ten-cell wet mechanical draft cooling tower (ASE 2015a). Separate emissions estimates for the proposed project during the construction phase, initial commissioning, and operation are each described next.

PROPOSED CONSTRUCTION EMISSIONS

Construction of the SEP is expected to take about 26 months. Construction of the project would require both laydown and construction parking areas. SEP would encompass 76 acres of property, which would allow laydown and construction parking to be accommodated on the project site. During the construction period, air emissions would be generated from: 1) vehicle and construction equipment exhaust; 2) fugitive dust from vehicle and construction equipment, including grading and earthmoving during plant construction, and windblown dust. It was conservatively assumed the construction activities would occur 10 hours per day and up to 23 days per month.

Estimates for the highest daily emissions and total annual emissions over the 26-month construction period are shown in **Air Quality Table 4**. The maximum annual construction emissions would occur from month 7 through month 18 for all criteria pollutants. For comparison, **Air Quality Table 4** also shows the construction emissions, shown in parentheses, from previous amended BEP II. As shown in **Air Quality Table 4,** all construction emissions would be reduced significantly except CO.

Air Quality Table 4
SEP, Estimated Maximum Construction Emissions

Construction Activity	NOx	VOC	PM10	PM2.5	CO	SOx
Maximum Daily Construction Emissions (lbs/day)	59.2 (147)	3.5 (20.5)	15.6 (83)	2.2 (23.3)	114.6 (62)	0.2 (0.2)
Peak Annual Construction Emissions (tons/year)	6.3 (19.43)	0.4 (2.7)	1.7 (3.31)	0.2 (1.4)	12.5 (8.18)	0.02 (0.04)

Source: ASE 2015a, ASE2015g, CEC2012a and independent staff analysis.
Note: 1. Numbers in parentheses represent the emissions from previously amended BEP II.
2. Maximum daily and annual emissions encompass contributions from project and linear construction activities. Different activities have maximum emissions at different times during the construction period; therefore, total maximum daily, monthly, and annual emissions might be different from the summation of emissions from individual activities.

PROPOSED INITIAL COMMISSIONING EMISSIONS

Gas turbine commissioning is the process of initial startup, tuning, and adjustment of the new turbine, auxiliary equipment and the emission control systems. The commissioning process would consist of sequential test operation of the gas turbine up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests would require approximately 1,250 hours of gas turbine operation. Up to approximately 350 hours of operation would be required prior to installing the selective catalytic reduction (SCR) and oxidation catalysts. Steam from the auxiliary boiler would be required during the gas turbine commissioning period. Therefore, the auxiliary boiler would undergo tuning to optimize the low-NOx burner operation prior to commencement of gas turbine commissioning. The boiler would need to operate for up to 200 hours during an initial commissioning period to allow for initial operation and tuning.

During the commissioning period, NOx and CO emissions would be higher than normal operating levels because the emission control systems would not be installed and/or fully operational. Emission rates for PM10, PM2.5, and SOx during initial commissioning are not expected to be higher than normal operating emissions because emissions from these pollutants are directly proportional to fuel use. Estimated emissions of criteria pollutants during the commissioning phase are summarized in **Air Quality Table 5**, with corresponding commissioning period emissions for the amended BEP II shown in parentheses.

Air Quality Table 5
SEP, Maximum Initial Gas Turbine Commissioning Emissions

Commissioning Source	NOx	VOC	PM10/ PM2.5	CO	SOx
CTG/HRSG (lb/hr)	625 (193.5)	464 (--)	8.0 (--)	4,919 (2,713)	4.9 (--)
CTG/HRSG (tons/commissioning period)	70.4 (50.1)	3.0 (51)	4.9 (7)	22.3 (407)	3.1 (--)
Facility total (tons/commissioning year)	140.1 (--)	22.7 (--)	38.8 (--)	87.7 (--)	8.8 (--)

Source: ASE 2015a, ASE2015g, CEC2012a and independent staff analysis.
Note: Numbers in parentheses represent the emissions from previously amended BEP II.

PROPOSED OPERATION EMISSIONS

The SEP, proposed as a nominally-rated 553 MW combined cycle power plant would include the following:

- A natural gas fired GE 7HA.02 combustion turbine generator (CTG) 3320 million British thermal units per hour (MMBtu/hr). The CTG would be equipped with a dry low-NOx combustor, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner and a heat recovery steam generator (HRSG). The duct burner would have a maximum rating of 221.6 MMBtu/hr on a higher heating value basis.
- An auxiliary boiler with a fuel input capacity of 66.3 MMBtu/hr to improve unit startup efficiency. The boiler would be equipped with an Ultra-low NOx burner and would have the capacity to produce 30,000 lb/hr of steam.
- A GE D652 steam turbine nominally rated at 210 MW.
- A 10-cell wet mechanical draft cooling tower with a circulation rate of 129,480 gallons/minute, which would be equipped with high efficiency drift eliminators.
- A Tier III diesel-fueled emergency fire pump engine (238 hp).

The SEP operation emission estimates would be based on vendor data and engineering estimates. Fuel for SEP would be exclusively pipeline-quality natural gas. The turbine would use dry low NOx combustors, combined with SCR, to limit emissions of NOx to 2.0 ppmvd (ppm by volume, dry basis), corrected to 15 percent O_2 ppmc (ppm corrected to 15 percent O_2), on a 1-hour average basis, and to 1.5 ppmc on an annual average basis. Best combustion practices, combined with the use of an oxidation catalyst, would be used to limit CO emissions to 2.0 ppmc on a 1-hour average basis, and 1.5 ppmc on an annual average basis. VOC emissions would be limited to 2.0 ppmc during duct firing and 1 ppmc without duct firing. PM10 and SO_2 emissions would be kept to a minimum through the exclusive use of natural gas.

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

- Manufacturer's guaranteed emission rates;
- Typical operating scenarios of CTG for estimating daily and annual emissions based on a worst-case day with one warm/hot start, one cold start and two shutdowns, 20 hours of operation with duct firing (except for the worst-case SOx emissions which is based on 24 hours of operation at the maximum fuel use) and a worst-case year with 150 warm/hot starts, 50 cold starts, 200 shutdowns, 5,500 hours of operation with no duct burner, and 1,500 hours of operation with duct burner;
- Typical operating scenarios of auxiliary boil for estimating daily and annual emissions based on a worst-case day with two startups and two shutdowns, 20 hours of operation at 100 percent load and a worst-case year with 400 hours startup/shutdown events and 6,600 hours of operation at 100 percent load;
- Operation of the diesel-fueled fire water pump engine for 50 hours per year for normal maintenance and testing; and
- Operation of the cooling tower for 24 hours per day, 8,760 hours per year.

Air Quality Table 6 lists the maximum operation emissions from the SEP estimated by the applicant. Emissions for NOx, CO, and VOC during startup and shutdown events would have higher emissions than during normal operation. Therefore the maximum hourly NOx, CO and VOC emissions are based on a turbine cold startup or shutdown. Since PM10/PM2.5 and SOx emissions are proportional to fuel use, PM10/PM2.5 and SOx have higher emissions rates during full-load operation. Therefore the maximum hourly PM10/PM2.5 and SOx emissions are based on each trubine operating at steady state. For comparison, the turbine emissions from the previously amended BEP II are also listed for comparison. While the NOx and CO emissions of SEP are somewhat higher than those from BEP II, emissions of other pollutants are expected to be lower.

Air Quality Table 6
SEP, Maximum Hourly Operation Emissions (lb/hr)

Operational Source	NOx	VOC	PM10/ PM2.5	CO	SOx
CTG/HRSG	188 (163.8)	35 (93.6)	10 (15)	148 (117)	4.9 (6.6)
Auxiliary Boiler	2 (0.6)	0.7 (0.1)	0.46 (0.3)	12.1 (1.9)	0.09 (0.1)
Emergency Fire Pump Engine	1.34 (1.7)	0.04 (0.1)	0.04 (0.1)	0.31 (0.6)	0 (0)
Cooling Tower	--	--	1.62 (1.36)	--	--

Source: ASE 2015a, ASE2015g, CEC2012a and independent staff analysis.
Note: Numbers in parentheses represent the turbine emissions from previously amended BEP II.

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 would occur. 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. The facility total daily emissions from the previously amended BEP II are also listed for comparison. As shown in **Air Quality Table 7**, the facility total daily emissions of all pollutants from SEP are expected to be lower than BEP II.

Air Quality Table 7
SEP, Maximum Daily Operational Emissions (lb/day)

Operational Source	NOx	VOC	PM10/ PM2.5	CO	SOx
CTG/HRSG	871.1 (1165.4)	277.6 (498.6)	238.2 (345)	881.4 (889.4)	117.8 (155.4)
Auxiliary Boiler	19.2 (0.6)	8.38 (0.1)	11.14 (0.3)	97 (1.9)	2.2 (0.1)
Emergency Fire Pump Engine	32.2 (1.7)	0.9 (0.1)	1.01 (0.1)	7.6 (0.6)	0.06 (0.0)
Cooling Tower	--	--	38.9 (32.64)	--	--
Facility Total	**922.4 (1,168)**	**286.8 (499)**	**289.3 (378)**	**986.0 (892)**	**120 (156)**

Source: ASE 2015a, ASE2015g, CEC2012a and independent staff analysis.
Note: Numbers in parentheses represent the emissions from previously amended BEP II.

Air Quality Table 8 summarizes the maximum annual emissions from the project based on the assumptions provided above. The facility total annual emissions from the previously amended BEP II are also listed for comparison. As shown in **Air Quality Table 8**, the facility total annual emissions of all pollutants from SEP are expected to be lower than BEP II.

Air Quality Table 8
SEP, Maximum Annual Operational Emissions (tons/year, tpy)

Operational Source	NOx	VOC	PM10/ PM2.5	CO	SOx
CTG/HRSG	83.2 (168.6)	23.2 (51.8)	31.4 (55.6)	67.6 (108.4)	8.7 (13.2)
Auxiliary Boiler	2.24 (0.7)	1.06 (0.1)	1.6 (0.3)	10.43 (2.3)	0.16 (0.1)
Emergency Fire Pump Engine	0.13 (0.0)	0.0 (0.0)	0.0 (0.0)	0.03 (0.0)	0.0 (0.0)
Cooling Tower	--	--	7.1 (5.0)	--	--
Facility Total	**85.6 (169.4)**	**24.3 (51.9)**	**40.1 (60.9)**	**78.0 (110.7)**	**8.8 (13.3)**

Source: ASE 2015a, ASE2015g, CEC 2012a and independent staff analysis.
Note: Numbers in parentheses represent the emissions from previously amended BEP II.

Ammonia would be injected into the flue gas stream as part of the SCR system to control NOx emissions. Not all of this ammonia would mix with the flue gases to reduce NOx; a portion of the ammonia would pass through the SCR and would be emitted unaltered out the stacks. These ammonia emissions are known as ammonia slip. The ammonia slip of this project is limited to 5 ppmvd corrected to 15% O_2 and averaged over 1 hour.

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 would 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 by the Automated Surface Observing Systems (ASOS) at Blythe Airport for the years 2009 through 2013. Upper air data from Elko, NV, 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. Environmental Protection Agency (EPA) (AERMOD Version 14134) to estimate the impacts of project-related NOx, PM10, PM2.5, CO and SOx emissions. A description of the modeling analysis for construction, operational and commissioning activities is provided in PTA Section 3.1.5 and Appendix 3.1-F (ASE 2015a).

NOx emissions from internal combustion sources are primarily in the form of nitric oxide (NO) rather than nitric dioxide (NO_2). Nitric oxide converts into NO_2 in the atmosphere, primarily through the reaction with ambient ozone. The applicant used AERMOD's Ozone Limiting Method (OLM) model option in the NO_2 1-hour modeling. The OLM option calculates NO_2 concentrations based on the ambient ozone concentrations using this principle. The hourly ozone data used for the OLM analysis were collected at the nearby Blythe monitoring station between 2009 and 2013 and preprocessed for use with AERMOD.

The applicant's modeled impacts were added to the available highest ambient background concentrations measured during 2010 to 2014 at the nearest monitoring station (see **Air Quality Table 2** above), except for the federal 1-hour NO_2 analysis where concurrent hourly background NO_2 were used. 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 construction activities would occur for approximately 26 months (including 4 months of commissioning) and various stages of construction would overlap throughout this period. To evaluate the overall potential air quality impacts from construction activities, the schedules for each activity were aligned and the maximum daily, monthly, and annual rolling 12-month emissions were developed. Because the adjacent BEP would operate during the SEP construction period, the construction impacts modeling analysis contains BEP.

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 9**. The values in bold represent values that equal or exceed the relevant air quality standard.

Air Quality Table 9
SEP, Ambient Air Quality Impacts from Construction (µg/m^3)

Pollutant	Averaging Time	Modeled Impact from SEP construction	Modeled Impact from BEP II Operation[a]	Combined Impact[b]	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	19.3 (60.8)	1.0	19.4	117	136.4	50	273
	Annual	1.2 (1.95)	0.2	1.3	22.1	23.4	20	117
PM2.5	24 hour	2.7 (12.8)	1.0	2.8	14.5	17.3	35	49
	Annual	0.14 (0.45)	0.2	0.3	6.5	6.8	12	57
CO	1 hour	849.6 (26.4)	8.5	849.6	3,680	4530	23,000	20
	8 hour	415.0 (10.1)	4.2	415.0	1,667	2082	10,000	21
NO_2[c]	State 1 hour	134.9 (62.8)	8.7	134.9	97.8	232.7	339	69
	Annual	3.4 (1.65)	0.1	3.5	13.3	16.8	57	29
SO_2	State 1 hour	1.6 (0.064)	1.3	1.6	20.9	22.5	655	3
	24 hour	0.29 (0.013)	0.29	0.32	2.6	2.92	105	3

Source: ASE 2015a, ASE2015g, CEC 2012a and independent staff analysis.

Note: Numbers in parentheses represent the emissions from previously amended BEP II.
[a] Modeled concentrations at location of maximum modeled concentration during SEP construction.
[b] Combined impact does not necessary equal to the sum of the individual impacts because the individual maxima may occur at different receptors or during different hours at the same receptor.
[c] The maximum 1-hour NO_2 concentration is based on OLM method, and the maximum annual NO_2 concentration shows an NOx to NO equilibrium ratio of 0.75.

As indicated in **Air Quality Table 9**, PM10 emissions from construction would contribute to existing violations of PM10 ambient air quality standards. Therefore, staff believes that PM10 emissions from construction could cause a significant impact over the construction period. The direct impacts of NO_2, in conjunction with worst-case background conditions, would not create a new exceedance of the current annual or 1-hour NO_2 state ambient air quality standards. Compliance with the new federal 1-hour NO_2 standard, which is averaged over three years, is not evaluated because the construction is expected to last only 26 months. The direct impacts of CO, PM2.5 and SO_2 would not be significant because construction of the project would neither cause nor contribute to an exceedance of these standards.

Maximum modeled impacts during the construction of SEP are also compared with those of the previously amended BEP II in **Air Quality Table 9**, with BEP II values shown in parentheses. Modeled PM10 and PM2.5 impacts are much lower than previously amended BEP II, and therefore SEP would make a reduced incremental impact to PM10 exceedances. Although modeled NO_2, SO_2 and CO construction impacts for SEP are higher than those for BEP II, the impacts are short term and still well below the most stringent air quality standards. Staff proposes to use best practices and extensive construction-period mitigation measures to minimize project impacts. Therefore, there are no significant impacts during project construction.

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 dispersion modeling analysis was performed by the applicant to identify off-site criteria pollutant impacts that would occur from routine operational emissions throughout the life of the project. The worst case 1-hour NO_2 and CO impacts reflect startup impacts; all other impacts reflect impacts that would occur during normal operation. The modeled impacts are extremely conservative, since the maximum impacts are evaluated under a combination of highest allowable emission rates, the most extreme meteorological conditions, and worst case background values, which are unlikely to all occur simultaneously. Emissions rates are shown in **Air Quality Tables 6** to **8**. The predicted maximum concentrations of criteria pollutants are summarized in **Air Quality Table 10**. Again, where available, values for BEP II are shown in parentheses for comparison. The values shown in bold represent values that equal or exceed the relevant air quality standards.

The modeling results indicate that the project's operational impacts would not create violations of NO_2, CO, PM2.5 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 mitigation (see the bold values in **Air Quality Table 10**). Secondary impacts caused by reaction of PM10 and ozone precursors are also discussed below.

Air Quality Table 10
SEP, Ambient Air Quality Impacts from Routine Operation (µg/m³)

Pollutant	Averaging Time	Modeled Impact from SEP Operation	Modeled Impact from BEP II Operation	Combined Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	**5.4 (2.85)**	**2.8**	**5.4**	**117**	**122.4**	**50**	**245**
	Annual	**0.6 (0.666)**	**0.5**	**0.7**	**22.1**	**22.8**	**20**	**114**
PM2.5	24 hour	5.4 (2.85)	2.8	5.4	14.5	19.9	35	57
	Annual	0.6 (0.666)	0.5	0.7	6.5	7.2	12	60
CO	1 hour	117.9 (213)	26.7	140.9	3,680	3821	23,000	17
	8 hour	9.2 (19.2)	7.2	13.2	1,667	1680	10,000	17
NO_2	State 1 hour	140.2 (113)	25.4	165.6[a]	97.8	263.4	339	78
	Federal 1 hour	54.8 (--[b])	11.3	--	77.1	114.8[c]	188	62
	Annual	0.16 (0.338)	0.21	0.35	13.3	13.7	57	24
SO_2	State 1 hour	2.9 (6.28)	4.1	6.9	20.9	27.8	655	4
	Federal 1 hour	2.9 (6.28)	4.1	6.9	13.1	20	196	10
	24 hour	0.42 (0.92)	0.64	0.79	2.6	3.4	105	3

Source: ASE 2015a, ASE2015g, CEC 2012a and independent staff analysis.
Note: Numbers in parentheses represent the emissions from previously amended BEP II.
[a] The combined maximum state 1-hour NO_2 concentration is conservatively estimated by the sum of individual concentrations from SEP and BEP.
[b] Modeled concentration was not provided for facility alone.
[b] The total federal 1-hour NO_2 concentrations combines those from BEP and SEP, as well as the maximum monthly hour-of day NO_2 background concentrations.

Maximum modeled operation impacts for the previously amended BEP II and the proposed SEP are compared in **Air Quality Table 10**. Maximum modeled concentrations from the proposed SEP are lower than those from the amended BEP II project for all pollutants and averaging periods except for 24-hour PM10/PM2.5 and state 1-hour NO_2 pollutants. For SEP, 24-hour PM10/PM2.5 concentrations are dominated by the impacts from the cooling tower. The SEP cooling tower is shorter and has a higher water circulation rate, leading to slightly higher hourly emissions and therefore higher impact. The higher 1-hour NO_2 impact is mostly due to the slightly higher startup hourly emission of the new turbine proposed for SEP. Maximum impacts from both the proposed SEP and previously amended BEP II are predicted to occur in roughly the same locations: NO_2, CO and PM10/PM2.5 impacts for all averaging periods and annual average SO_2 impacts are predicted to occur immediately south of the facility fence line, because for both projects these impacts are predominantly as a result of downwash from sources with short stacks (emergency diesel fire pump engine and cooling tower). Impacts that are predominantly a result of the gas turbine (longer-term SO_2 and NO_2 and CO impacts during gas turbine startups) occur farther from the project site.

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 PM2.5, and NOx and VOC are also precursors to ozone. Gas-to-particulate conversion in ambient air involves complex chemical and physical processes that depend on many factors, including local humidity, pollutant travel time, 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 chemical composition of ambient PM10 or PM2.5. However, because of the known relationship of NOx and SO_2 emissions to secondary PM10/PM2.5 formation, it can be said that the emissions of NOx and SO_2 from the project have the potential (if left unmitigated) to contribute to PM10 and PM2.5 concentrations 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. 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.

Ammonia (NH_3) is a particulate precursor but not a criteria pollutant because there is no ambient air quality standard for ammonia. Reactive with sulfur and nitrogen compounds, ammonia can be found from natural sources, agricultural sources, and as a byproduct of tailpipe controls on motor vehicles and stack controls on power plants.

Energy Commission staff recommends limiting ammonia slip emissions to the maximum extent feasible. This level of control is appropriate for avoiding unnecessary ammonia emissions, consistent with staff policy to reduce emissions of all nonattainment pollutant precursors to the lowest feasible levels. Consistent with District permit conditions, staff recommends an ammonia slip limit of parts per million by volume dry ppmvd corrected to 15% O_2 and averaged over 1 hour.

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. Below the zone of restricted mixing caused by 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 with little dispersion. Fumigation conditions are generally short-term in nature (24 hours or less). The applicant analyzed the air quality impacts under fumigation conditions from the SEP project using the SCREEN3 model (Version 96043). Similar to routine operation impact analysis, the worst case NO_2 and CO impacts reflect startup impacts, and all other impacts reflect impacts that would occur during normal operation. The fumigation impacts are shown in **Air Quality Table 11**. Similar to operational impacts, fumigation impacts are estimated to not cause new violations of ambient air quality standards, but could further exacerbate existing violations of the state PM10 standard (see the bold values in **Air Quality Table 11**). The fumigation impacts of previously amended BEP II were only evaluated for 1 hour CO, NO_2, SO_2 and only during normal operation periods instead of startup periods. Therefore, the fumigation impacts of previously amended BEP II are not compared here.

Air Quality Table 11
SEP, Ambient Air Quality Impacts during Fumigation (μg/m³)

Pollutant	Averaging Time	Fumigation Impacts from SEP Operation[a]	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	**2.4**	**117**	**119.4**	**50**	**239**
PM2.5	24 hour	2.4	14.5	16.9	35	48
CO	1 hour	144.8	3,680	3,825	23,000	17
	8 hour	10.1	1,667	1677	10,000	17
NO_2	State 1 hour	115.6	97.8	213.4	339	63
SO_2	State 1 hour	2.3	20.9	23.2	655	4
	24 hour	0.82	2.6	3.4	105	3

Source: ASE 2015a, ASE2015g, ASE2015i and CEC2012a with independent staff analysis.
[a] Staff conservatively assumes that maximum fumigation impacts from gas turbine and auxiliary boiler overlap with each other. The maximum concentrations during the fumigation are the sums of concentrations from the gas turbine and the auxiliary boiler.

IMPACTS DURING INITIAL COMMISSIONING

Commissioning impacts would occur over a short-term period needed to complete the commissioning. The commissioning of the SEP project is expected to be completed within 4 months. The commissioning emissions estimates are based on partial load operations before the emission control systems become fully operational. Only NOx and

CO impacts are analyzed here because these are the only criteria pollutants that would 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 12**. As shown in **Air Quality Table 12**, the commissioning-phase emissions would not cause new exceedences of any state or federal air quality standard.

Maximum modeled impacts during the commissioning of SEP are also compared with those of the previously amended BEP II in **Air Quality Table 12**, with BEP II values shown in parentheses. Although modeled NO_2, and 1-hour CO impacts for SEP are higher than those for BEP II, the impacts are short term and below the most stringent air quality standards. Therefore, there are no significant impacts during the SEP commissioning.

Air Quality Table 12
SEP, Ambient Air Quality Impacts during Commissioning (µg/m^3)

Pollutant	Averaging Time	Modeled Impact from SEP Operation	Modeled Impact from BEP Operation	Combined Impact	Background	Total	Limiting Standard	Percent of Standard
CO	1 hour	4,266 (2,922)	26.7	4,288	3,680	7,968	23,000	35
	8 hour	961 (1,026)	7.2	963	1,667	2,630	10,000	26
NO_2	State 1 hour	265.9 (167.9)	18.7	--	97.8	321[a]	339	95

Source: ASE 2015a, ASE2015g, ASE2015i and CEC 2012a with independent staff analysis.
Note: Numbers in parentheses represent the emissions from previously amended BEP II.
[a] The combined maximum state 1-hour NO_2 concentration combines those from BEP and SEP, as well as the maximum monthly hour-of day NO_2 background concentrations.

MITIGATION

APPLICANT'S PROPOSED MITIGATION

Applicant's Construction Mitigation

The Applicant proposes to reduce construction-related emissions by implementing a construction fugitive dust and diesel-fueled engine control plan. This plan would focus on reducing construction air quality impacts and would encompass the mitigation measures including:

- Applying dust suppressants to unpaved roads and disturbed areas;
- Limiting onsite vehicle speeds to 10 mph and posting the speed limit;
- Applying dust suppressants frequently during periods of high winds when excavation/grading is occurring;

- Sweeping onsite paved roads and entrance roads on an as-needed basis;
- Replacing ground cover in disturbed areas as soon as practical;
- Covering truck loads when hauling material that could be entrained during transit;
- Applying dust suppressants or covers to soil stockpiles and disturbed areas when inactive for more than two weeks;
- Using ultra-low sulfur diesel fuel (15 ppm sulfur) in all diesel-fueled equipment;
- Using Tier 3 and Tier 4 construction equipment to the extent feasible;
- Maintaining all diesel-fueled equipment per manufacturer's recommendations to reduce tailpipe emissions;
- Limiting diesel heavy equipment idling to less than 5 minutes, to the extent practical; and
- Using electric motors for construction equipment to the extent feasible.

<u>Applicant's Operation Mitigation</u>

During operation, the appropriate mitigation measure is to minimize potential air emissions. This is accomplished by the careful design of the project, including the installation of the best available control technology (BACT) to minimize air emissions. Air quality impacts would be further mitigated by providing emission offsets. The remainder of this section describes the BACT analysis and the emission offset mitigation.

Emission Controls

For the gas turbine, the proposed BACT for NOx emissions is the use of dry low NOx combustors with SCR to control NOx emissions to 2.0 ppmvd (1-hour average). BACT for CO emissions is good combustion practices and the installation of oxidation catalyst systems to control CO emissions to 2.0 ppmvd (averaged over 1-hour). BACT for VOC emissions is good combustion practices to control VOC emissions to 2.0 ppmvd with duct firing and 1.0 ppmvd (3-hour average) without duct firing.

For the auxiliary boiler, NOx emissions would be minimized through the use of ultra-low NOx burners to achieve a controlled NOx emission rate of 7 ppmvd @ 3% O2 (averaged over 3 hours). CO and VOC emissions would be minimized through good combustion practices and emission rates of 50 and 10 ppm, respectively. Good combustion practices and pipeline quality natural gas would be used to minimize PM10/PM2.5 and SO2 emissions.

The cooling towers would use drift eliminators to minimize cooling tower drift to 0.0005 percent, which would minimize PM10 emissions.

Emission Offsets

In addition to emission control strategies included in the project design, the applicant also proposed to use emission reduction credits (ERCs) to offset the increases in emissions of nonattainment pollutants that occur at the facility above MDAQMD offset threshold levels. Because the proposed SEP is considered a modification to the existing BEP, the facility emissions are the sum of permitted emissions at BEP and proposed emissions at SEP. **Air Quality Table 13** shows the quantity of ERCs required by District and Energy Commission staff under CEQA, as well as the quantity identified by SEP. The additional CEQA offsets are needed to cover the emissions from zero up to the local district trigger level, which the local district does not require to be offset.

Air Quality Table 13
SEP Emission Offset Requirements and ERC Sources

	ERC Identification	NOx (tpy)	VOC (tpy)	SOx (tpy)	PM10 (tpy)
Existing BEP Emissions		97	24	24	97
Proposed Emissions, SEP		85.6	24.3	8.8	40.1
Proposed Net Reductions, BEP[a]		0.0	0.0	-12.0	-40.1
Total Facility Emissions (BEP+SEP)		182.6	48.3	20.8	97.0
MQAQMD Emission Offset Thresholds[b]		25	25	25	15
BEP II Offsets required by MDAQMD		85.6[c]	23.3[d]	0	0
BEP II Offsets normally required by Energy Commission		85.6	24.3[e]	8.8[f]	0[g]
Existing ERC Held or Owned by APHUS	**MDAQMD (#0099)**	**200**	**0**	**0**	**0**
Total ERCs Identified:		**200**	**0**	**0**	**0**
Transfer from NOx to VOC (Rule 1305(C))		(23.3)	23.3		
Total ERCs Identified:		176.7	23.3		
Sufficient for MDAQMD Requirements?		Yes	Yes	Yes	Yes
Transfer from NOx to VOC and SOx		**(33.1)**	**24.3**	**8.8**	
Total ERCs Identified:		**166.9**	**24.3**	**8.8**	
Sufficient for Energy Commission Requirements?		**Yes**	**Yes**	**Yes**	**Yes**

Source: ASE2015a, ASE2015m with independent staff analysis.
[a] Proposed reductions in permitted emissions from BEP.
[b] CO offsets are not required because MQAQMD is in attainment of the CO standards.
[c] Existing BEP NOx emissions were previously fully offset, so offsets are required only for the net increase from SEP.
[d] Per District Rule 1305(a)(2)(b)(ii)b.II, offsets must be provided for emissions that exceed the 25 tpy threshold amount (48.3 – 25 = 23.3 tpy of offsets required).
[e] Full offsets are required for the VOC emissions from SEP.
[f] District approved that SEP emissions can be fully offset by the emission reduction from BEP. However, staff recommends that full offset for SEP SOx emissions as BEP SOx emissions be required as they were not previously offset.
[g] Existing BEP PM10 emissions were previously fully offset, so emission reduction from BEP can be used to offset SEP PM10 emissions.

AltaGas Power Holdings (U.S.) Inc (APHUS) owns 200 tpy under MDAQMD Certificate Number 0099. The NOx ERCs were generated by the replacement of eleven natural gas-fired internal combustion engine driven engines equipped with the latest control technology. The reduction occurred at a Southern California Gas Company facility located in Blythe. The District finds that the emission reduction credits resulting from the engine replacements meet current Reasonable Available Control Technology (RACT) requirements and do not require adjustment at this time.

SEP has also proposed to offset both volatile organic compound (VOC) emissions with NOx ERCs. The use of inter-district, inter-air basin and inter-pollutant offsets is specifically allowed by Rule 1305(B)(4) through (6) (in consultation with Air Resources Board (ARB) and U.S. EPA, and in the case of inter-pollutant offsets, with the approval of U.S.EPA). The District therefore determines that this inter-pollutant trade is technically justified because NOx and VOC are both ozone precursors and that the inter-pollutant trade would not cause or contribute to a violation of the NO_2 or ozone ambient air quality standards. As previously approved for BEPII, pursuant to Rule 1305(C) the offset ratio for NOx and VOC is 1:1. Staff concurs in the use of a 1:1 ratio for inter-pollutant offsets. However, the amounts of VOC ERCs required by the District and Energy Commission staff for CEQA purposes are different. District requires ERCs to offset emissions of both SEP and BEP above District ERC thresholds. Under CEQA requirement, staff recommends that the Energy Commission require ERCs for SEP in the amount needed to fully offset the emissions (i.e. zero thresholds).

The applicant proposed to use the Simultaneous Emission Reductions (SERs) from the original Blythe Energy Project (BEP) to offset PM emissions for SEP. Staff is aware of concerns expressed by some agencies that these SERs are not real reductions but unused caps in the potential to emit (PTE), or “paper credits” and not real reductions in actual emissions. However, since BEP and SEP are under the same ownership and PM10 emissions from BEP have been fully offset, all PM10 emissions can be offset by the original ERCs submitted for BEP. There would be no net increase of PM10 emissions from BEP and SEP and therefore no significant impact under CEQA. Therefore staff agrees with the use of SERs to offset PM10 emissions for the two projects. The District has also approved the use of SERs.

Similarly the applicant proposed to use the SERs from BEP to offset SOx emissions for SEP, which has been approved by the District. However, since the SOx emissions from BEP have not been offset before, staff does not agree the SERs from BEP can be used to offset SEP under CEQA. Instead, staff proposes to allow the surplus NOx offsets to satisfy the SOx mitigation requirements at a ratio of 1:1. Because NOx and SOx are both precursors of PM10, the NOx offsets would be equivalent to SOx emissions mitigation for PM10.

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 factors. These 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 onto 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.

As shown in **Air Quality Table 9** above, direct impacts of NO_2, CO, SO_2, and PM2.5 would not be significant. Direct PM10 impacts would be reduced by the proposed mitigation measures 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. Staff concludes that 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 PDOC for gas turbine emissions of 2.0 ppmvd NOx (1-hour basis), 2.0 ppmvd CO (1-hour basis) and 5.0 ppmvd NH_3 (1-hour basis) are the most stringent according to the current U.S. EPA and ARB recommendations. The CEQA mitigation approach for PM10/PM2.5, SOx, and ozone precursor pollutants (NOx and VOC) includes emission reductions as shown in **Air Quality Table 13** (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.

Staff Proposed Mitigation

Staff Proposed Construction Mitigation

Additional measures recommended by staff would reduce construction-phase impacts to a less than significant level by further reducing construction emissions of particulate matter and combustion contaminants. Staff believes that the short-term and variable nature of construction activities warrants a qualitative approach to mitigation.

Construction emissions and the effectiveness of mitigation varies widely depending on variable levels of activity, the specific work taking place, the specific equipment, soil conditions, weather conditions, and other factors, making quantification of emissions and air quality impacts difficult. Despite this uncertainty, there are a number of feasible control measures that can and should be implemented to significantly reduce construction emissions. Staff includes proposed staff Conditions of Certification **AQ-SC1** through **AQ-SC5** to implement these requirements. These conditions are consistent with both the applicant's proposed mitigation and the conditions of certification adopted in similar prior licensing cases. Compliance with these conditions is expected to reduce or eliminate the potential for significant adverse air quality impacts during construction of the project.

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 the PTA. When the proposed offsets are taken together in the ambient setting, staff believes that the project's emissions of NOx, SOx, PM10, and VOC would be fully mitigated by the proposed offsets.

CUMULATIVE IMPACTS

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

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

The following subsection includes two additional analyses:

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

SUMMARY OF PROJECTIONS

The Riverside County portion of the MDAB is designated as unclassified or attainment for all federal ambient air quality standards and the state CO, NO_2, SO_2 and PM2.5 standards, but is designated as non-attainment for State ozone and PM10 standards.

Ozone

Since a portion of San Bernardino County in the MDAB is currently classified as non-attainment for the federal 8-hour ozone standard north and west of the project site, the District is required to prepare and adopt an ozone attainment plan for submittal to the U.S. EPA describing how it would attain the federal 8- hour standard. The District completed this plan in 2008. The project is not specifically subject to the provisions in the federal attainment plan and the site is outside of the non-attainment area.

The District is required to prepare and adopt a state ozone attainment plan for submittal to ARB. The latest state ozone attainment plan was adopted by MDAQMD in 2004. The MDAQMD 2004 Ozone Attainment Plan contains attainment plans for both federal and state ozone standards. The MDAQMD did not propose to adopt any additional control measures as part of the 2004 Plan. Additionally, while there are no additional control measures for direct ozone precursor reduction as part of the federal 2008 attainment plan, MDAQMD is committed to adopt all applicable Federal Reasonably Available Control Technology (RACT) rules it proposed in 8-hour Reasonably Available Control Technology – State Implementation Plan Analysis (RACT SIP Analysis) in 2006. In addition, the MDAQMD updated and identified new measures in 2007, which adopted through 2014, as the State of California mandates use of all feasible measures. The RACT rules and other new measures do not impact the SEP emission sources as proposed.

Particulate Matter

Since a portion of San Bernardino County in the MDAB is currently classified as non-attainment for the federal PM10 standards north and west of the project site, the District is required to prepare and adopt an attainment plan for submittal to the U.S. EPA describing how it would achieve attainment with the federal PM10 standards. However, the SEP site is in Riverside County, outside the federal non-attainment area and not subject to the provisions in the federal attainment plan. There is no legal requirement for air districts to provide plans to attain the state PM10 standard, so air districts have not developed such plans. Therefore, there are no air quality management plan particulate emission control measures applicable to the modified SEP project.

With the implementation of staff-recommended construction and operation CEQA mitigation measures, staff believes that it is unlikely that the modified SEP project would have significant impact on particulate matter ambient concentrations.

LOCALIZED CUMULATIVE IMPACTS

Staff estimates the project's contributions to localized cumulative impacts through air dispersion modeling. To represent *past* and, to an extent, *present projects* that contribute to ambient air quality conditions, the Energy Commission staff recommends the use of ambient air quality monitoring data, referred to as the *background*. The staff takes the following steps to estimate what are additional appropriate "present projects" that are not represented in the background and "reasonably foreseeable projects:"

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

Once the modeling results are interpreted, they are added to the background ambient air quality monitoring data and thus the modeling portion of the cumulative assessment is complete. Once the cumulative project emission impacts are determined, the necessity to mitigate the proposed project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or the applicant.

The applicant requested a list of projects that are within a six-mile radius of the proposed project and are currently in the permitting process, are undergoing CEQA review, or recently received an ATC from the MDAQMD. The District responded that while there are no projects meeting these criteria, BEP should be modeled and added to monitored background to ensure that potential local cumulative impacts are adequately evaluated. The applicant included BEP in the modeling results presented in **Air Quality Table 10** to **12** as requested. Therefore, the cumulative impacts from the project have been addressed above.

COMPLIANCE WITH LORS

FEDERAL

The U.S. EPA is currently responsible for completing the Federal Prevention of Significant Deterioration (PSD) review requirements for projects proposed in the MDAQMD. The federal PSD requirements apply on a pollutant-specific basis to any project that is a new major stationary source or a major modification to an existing stationary source. Since the SEP is owned by the same parent company that owns and operates BEP, the projects are on contiguous properties and have the same SIC code, for federal PSD purposes they are considered part of the same stationary source. Existing BEP is not an existing major source and SEP emissions are below major source thresholds; SEP is not a major modification to an existing major source, and SEP is not a major source itself. Consequently, the SEP is not subject to PSD review.

STATE

The applicant has demonstrated that the project would comply with Section 41700 of the California State Health and Safety Code, which restricts emission that would cause nuisance or injury. Compliance with PDOC and the staff's proposed Conditions of Certification enable staff's affirmative finding.

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 local air district (MDAQMD in this case) certifies that complete offsets have been identified and would be obtained. The MDAQMD has determined that a sufficient quantity of offsets have been identified and that the offsets would be obtained. Based on the Energy Commission staff's proposed ERC compliance plan, the offsets would also satisfy CEQA mitigation requirements.

LOCAL

The District released its initial new source review document, or PDOC (ASE2015m), for the proposed project on December 17, 2015. The MDAQMD found that the proposed SEP, after application of the proposed permit conditions (including BACT requirements), would comply with all applicable MDAQMD Rules and Regulations. The PDOC conditions are presented in the proposed Conditions of Certification of this Staff Assessment (**AQ-1** to **AQ-68**). The District will issue a Final Determination of

Compliance (FDOC) after reviewing and responding to comments received on the PDOC.

FACILITY CLOSURE

Eventually, SEP would 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 emissions from the demolition and dismantling activities. Staff recommends that a Facility Closure Plan be submitted to the Energy Commission Compliance Project Manager prior to demolition and dismantling activities to demonstrate compliance with all local, state, and federal rules and regulations during closure and demolition.

CONCLUSIONS AND RECOMMENDATIONS

Staff has reviewed the applicant's documentation and the PDOC issued by the MDAQMD and concludes that the SEP project would likely conform with applicable federal, state, and MDAQMD air quality laws, ordinances, regulations, and standards. SEP would not cause significant air quality impacts, provided that the following Conditions of Certification are included, as shown below. Staff recommends that these conditions of certification be required.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in **Air Quality Appendix AIR-1**. As discussed there, the SEP would comply with the Emission Performance Standard established by SB 1368 for base load generation. The project would also be subject to federal and Air Resources Board mandatory GHG reporting requirements and any GHG reduction or trading requirements developed by the ARB as GHG regulations are implemented.

If the project design includes an air cooled condenser (ACC or "dry cooling") instead of a wet cooling tower, criteria air pollutants from the cooling tower would be avoided. But emissions from the combustion turbine and HRSG might increase or decrease, depending on how the project owner sizes the ACC and incorporates the ACC into the project design and operations. Staff does not see any fatal flaws in the area of air quality in incorporating an ACC into the SEP project design.

PROPOSED CONDITIONS OF CERTIFICATION

STAFF-RECOMMENDED CONDITIONS OF CERTIFICATION

The following section shows the conditions of certification with proposed changes from the approved BEP II, 2012 Order. ~~Strikethrough~~ is used to indicate deleted language and **underline and bold** is used for new language. Staff proposed Conditions of

Certification to provide mitigation during the construction phase of the project are **AQ-SC1** to **AQ-SC5**, and those for operation are **AQ-SC6**, **AQ-SC7** and **AQ-SC9**. District conditions of certification from the current PDOC are shown as conditions **AQ-1** to **AQ-68**. Staff is also proposing to renumber these previously approved Conditions of Certification to ease cross reference to current District documents.

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 Compliance Project Manager (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, for approval, an AQCMP, which details the steps to be taken and the reporting requirements necessary to ensure compliance with conditions of certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5**.

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

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 ~~Air Quality Construction Mitigation Plan (AQCMP)~~ **following** mitigation measures for the purposes of ~~minimizing fugitive dust emission creation from construction activities and~~ preventing all fugitive dust plumes from leaving the project's boundary. ~~The following fugitive dust mitigation measures shall be included in the AQCMP required by **AQ-SC2**, and any~~ **Any** deviation from the ~~AQCMP~~**following** mitigation measures shall require prior CPM notification and approval.

~~A~~ **a)**. The main access roads through the facility to the power block areas would be either paved or stabilized using soil binders, or equivalent methods, to provide a stabilized surface that is similar for the purposes of dust control to paving, that may or may not include a crushed rock (gravel or similar material with fines removed) top layer, prior to initiating construction in the main power block area, and delivery areas for operations materials (chemical, replacement parts, etc.) would be paved prior to taking initial deliveries.

~~B~~**b**) All unpaved ~~construction~~ roads and ~~unpaved operation site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as CARB approved soil stabilizers, and shall not increase any other environmental impacts including loss of vegetation to areas beyond where the soil stabilizers are being applied for dust control. All other~~ **and** disturbed areas in the project **and laydown** construction sites shall be watered as frequently as necessary ~~during grading; and after active construction activities shall be stabilized with a non-toxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods, in order~~ to comply with the dust mitigation objectives of **AQ-SC4.** The frequency of watering can be reduced or eliminated during periods of precipitation.

~~C~~**c**) No vehicle shall exceed 10 miles per hour on unpaved areas within the **project and laydown** construction sites~~, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions~~.

~~D~~**d**) The construction site entrances shall be posted with visible speed limit signs.

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

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

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

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

~~I~~**i**) Construction areas adjacent to any paved roadway ~~below the grade of the surrounding construction area or otherwise directly impacted by sediment from site drainage~~ shall be provided with sandbags or other ~~equivalently effective measures to prevent run-off to roadways, or other similar run-off control~~ measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) **to prevent runoff to roadways**~~only when such SWPPP~~

~~measures are necessary so that the condition does not conflict with the requirements of the SWPPP~~.

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

~~K~~**k**) At least the first 500 feet of any public roadway exiting ~~from~~ the construction site ~~or exiting other unpaved roads en route from the construction site or construction staging areas~~ shall be swept ~~as needed~~ **visually clean, using wet sweepers or air filtered dry vacuum sweepers, at least twice daily** (**or** less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff ~~resulting~~ from the construction site activities is visible on the public paved roadways.

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

~~M~~**m)** 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 two feet of freeboard.

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

Verification: The AQCMM shall provide a Monthly Compliance Report to include the following to demonstrated control of fugitive dust emissions:

A. A summary of all actions taken to maintain compliance with this condition,

B. Copies of any complaints filed with the air district or facility representatives in relation to project construction, and

C. 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 monitor construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported off the project site and within ~~400~~**100** feet upwind of any regularly occupied structures not owned by the project owner indicates that existing mitigation measures are not resulting in effective mitigation. ~~The AQCMP shall include a section detailing how the additional mitigation measures would be accomplished within the time limits specified.~~ 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 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 would not result upon restarting the shutdown activity. The ~~owner/operator~~**project owner** 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 AQCMM shall provide the CPM a Monthly Compliance Report to include:

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the district or facility representatives in relation to project construction; and

C. 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-SC5 Diesel-Fueled Engines Control: The AQCMM shall submit to the CPM, in the Monthly Compliance Report, a ~~table~~ **construction mitigation report** that demonstrates compliance with the AQCMP mitigation measures for the purposes of controlling diesel construction-related emissions. **The following off-road diesel construction equipment mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by AQ-SC2, and any** ~~Any~~ deviation from the AQCMP mitigation measures **shall** require~~s~~ prior CPM notification and approval.

~~All off-road diesel construction equipment used in the construction of this facility shall be powered by the cleanest engines available that also comply with the California Air Resources Board's (CARB's) Diesel Emission Control Strategy (verified DECS) for in-use vehicles and shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**. The AQCMP measures shall include the following, with the lowest-emitting engine chosen in each case, as available:~~

~~a. All off-road compression ignition engines shall comply with the California Air Resources Board's (CARB's) Diesel Emission Control Strategy (verified DECS) for in-use, off-road vehicles.~~

~~b. To meet the highest level of emissions reduction available for the engine family of the equipment, each piece of diesel-powered equipment shall be powered by a Tier 4 engine, a Tier 4i engine or a Tier 3 engine with a post-combustion device retrofit device verified by the CARB or the US EPA. For PM, the retrofit device shall be a particulate filter if verified, or a flow-thru filter, or at least an oxidation catalyst. For NOx, the device shall meet the latest Mark level verified to be available (as of January 2012, none meet this NOx requirement).~~

~~c. For diesel powered equipment where the requirements of Part "b" cannot be met, the equipment shall be equipped with a Tier 3 engine without retrofit control devices or with a Tier 2 or lower Tier engine using retrofit controls verified by CARB or US EPA as the best available control device to reduce exhaust emissions of PM and nitrogen oxides (NOx) unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices can be considered "not practical" for the following, as well as other, reasons:~~

~~1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection Agency to control the engine in question and the highest level of available control using retrofit or Tier 1 engines is being used for the engine in question; or~~

~~2. The use of the retrofit device would unduly restrict the vision of the operator such that the vehicle would be unsafe to operate because the device would impair the operator's vision to the front, sides, or rear of the vehicle, or~~

~~3. The construction equipment is intended to be on site for 10 work days or less.~~

~~d. The CPM may grant relief from a requirement in Part "b" or "c" if the AQCMM can demonstrate a good faith effort to comply with the requirement and that compliance is not practical.~~

~~e. The use of a retrofit control device may be terminated immediately provided that the CPM is informed within 10 working days of the termination and a replacement for the equipment item in question meeting the level of control required occurs within 10 work days of termination of the use (if the equipment would be needed to continue working at this site for more than 15 work days after the use of the retrofit control device is terminated) if one of the following conditions exists:~~

~~1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in~~

~~exhaust back pressure.~~

~~2. The retrofit control device is causing or is reasonably expected to cause engine damage.~~

~~3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.~~

~~4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.~~

~~f. All equipment with engines meeting the requirements above shall be properly maintained and the engines tuned to the engine manufacturer's specifications. Each engine shall be in its original configuration and the equipment or engine must be replaced if it exceeds the manufacturer's approved oil consumption rate.~~

~~g. Construction equipment would employ electric motors when feasible.~~

~~h. If the requirements detailed above cannot be met, the AQCMM shall certify that a good faith effort was made to meet these requirements and this determination must be approved by the CPM.~~

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

a) 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.

b) All construction diesel engines with a rating of 50 hp or higher shall meet, at a minimum, the Tier 4 or 4i California Emission Standards for Off-Road Compression-Ignition Engines, as specified in California Code of Regulations, Title 13, section 2423(b) (1), unless a good faith effort to the satisfaction of the CPM that is certified by the on-site AQCMM demonstrates that such engine is not available for a particular item of equipment. In the event that a Tier 4 or 4i engine is not available for any off-road equipment larger than 50 hp, that equipment shall be equipped with a Tier 3 engine, or an engine that is equipped with retrofit controls to reduce exhaust emissions of nitrogen oxides (NOx) and diesel particulate matter (DPM) to no more than Tier 3 levels unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is "not practical" for the following, as well as other, reasons.

1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection

Agency to control the engine in question to Tier 3 equivalent emission levels and the highest level of available control using retrofit or Tier 2 engines is being used for the engine in question; or

2. The construction equipment is intended to be on site for ten working days or less.

3. The CPM may grant relief from this requirement if the AQCMM can demonstrate a good faith effort to comply with this requirement and that compliance is not practical.

c) The use of a retrofit control device may be terminated immediately, provided that the CPM is informed within ten working days of the termination and that a replacement for the equipment item in question meeting the controls required in item "b" occurs within ten days of termination of the use, if the equipment would be needed to continue working at this site for more than 15 days after the use of the retrofit control device is terminated, if one of the following conditions exists:

1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in back pressure.

2. The retrofit control device is causing or is reasonably expected to cause engine damage.

3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.

4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

d) All heavy earth-moving equipment and heavy duty construction-related trucks with engines meeting the requirements of (b) above shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

e) All diesel heavy construction equipment shall not idle for more than five minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement.

f) Construction equipment would employ electric motors when feasible.

Verification: The AQCMM shall include **a table** in the MCR to demonstrate control of diesel construction-related emissions, including:

A. a summary of all actions taken to control diesel construction related emissions;

B. A list of all heavy equipment used on site during that month, showing the Tier level of each engine and the basis for alternative compliance with this condition for each engine not meeting Part "b". The list shall include the owner of the equipment and a letter from each owner indicating that the equipment has been properly maintained; and

C. 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 provide the CPM copies of all District issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility. The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any 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 ATC, PTO, and 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.

~~QUARTERLY OPERATIONS REPORT~~

AQ-SC7 The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with Conditions of Certification herein. The Quarterly Operational Report shall specifically **state that the facility meets all applicable conditions of certification or** note or highlight **all** instances of noncompliance.

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

AQ-SC8 DELETED; Order 12-0425-3a

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~~17**. The ERC list shall contain evidence that the MDAQMD and the U.S. EPA have 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 and the U.S. EPA, 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 would 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)**~~	~~**VOC (tpy)**~~	~~**PM10 (tpy)**~~
~~CRIT Road Paving~~	~~MDAQMD (pending)~~			~~126~~
~~Existing ERC Held or Owned by Caithness~~	~~MDAQMD -0058~~	~~25~~		
~~Existing ERC Held or Owned by Caithness~~	~~MDAQMD -0051~~	~~175~~		
~~SoCal Gas Compressor Engines~~	~~MDAQMD – 0052~~	~~250~~		

~~Note: MDAQMD allows inter-pollutant trading of NOx ERCs to fully offset VOC.~~

ERC Identification	**NOx (tpy)**
MDAQMD (0099)	**200**

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 construction. The list of ERC's shall include evidence that the U.S. EPA and California ARB concurs with the determination that the ERCs are valid~~, including road-paving~~. 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 DELETED; Order 12-0425-3a

AQ-SC11 DELETED; Order 12-0425-3a

DISTRICT DETERMINATION OF COMPLIANCE CONDITIONS (MDAQMD 2015)

~~**[Two (2) individual 2019.6 MMBtu/hr F Class Gas Turbine Generators**~~ ~~[MDAQMD Permit Numbers: B008877 and B008878]~~ **3320 MMBtu/hr Natural Gas Fired GE 7HA.02 Gas Turbine Generator, Permit Number: BXXXXX**

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 twenty-four hour basis and not exceeding 0.25 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 KKKK (Standards of Performance for New Stationary Gas Turbines) **and TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units)**. This equipment is also subject to ~~the Prevention of Significant Deterioration (40 CFR 52.)~~ **40 CFR Part 98 – Mandatory Greenhouse Gas Reporting,** ~~and~~ Federal Acid Rain (Title IV) programs **and Federal Operating Permit (Title V) programs**. Compliance with all applicable provisions of these regulations is required. **In the event of conflict between these conditions, State and Federal regulations, the more stringent requirements shall govern.**

Verification: At least ninety (90) days prior to the first firing of fuel in either turbine, the project owner shall provide the District, ~~C~~ARB and CPM with copies of the federal ~~PSD~~**Operating** and Acid Rain permits. The project owner shall provide updates to their Title V permit within 30 days of receipt.

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 **and during the commissioning period as defined in this permit**:

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

i. NOx as NO_2 – ~~17.9~~**26.0** lb/hr (based on 2.0 ppmvd corrected to 15% oxygen and averaged over one hour)

ii. CO – ~~10.9~~**16.2** lb/hr (based on 2.0 ppmvd corrected to 15% oxygen and averaged over one hour)

iii. NH3 – 5 ppmvd (corrected to 15% oxygen and averaged over one hour)

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

i. VOC as CH_4 – ~~6.3~~**9.3** lb/hr (based on 2.0 ppmvd ~~(1.0 ppmvd with no duct firing)~~ **with duct firing** corrected to 15% oxygen and averaged over one hour)

ii. VOC as CH_4 – 4.6 lb/hr (based on 1.0 ppmvd without duct firing corrected to 15% oxygen and averaged over three hour)

~~ii~~**iii**. SOx as SO_2 – ~~3.3~~**4.9** lb/hr (based on 0.5 grains/100 dscf fuel sulfur)

~~iii~~**iv**. PM_{10} – ~~7.5~~**10.0** 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 A CEMS shall be installed and operated to demonstrate compliance with the NOx emissions limit specified in 40 CFR 60 Subpart KKKK. A quality assurance plan shall be developed and kept on site and available pursuant to §60.4335.

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

AQ-~~5~~**6** Emissions of CO and NOx from this equipment**, including the duct burner,** ~~shall only~~**may** exceed the limits contained in Condition **AQ-4** during startup and shutdown periods as follows:

a. Startup ~~is~~**shall be** defined as the period beginning with ignition and lasting until ~~either~~ the ~~equipment~~**power block** has reached operating permit limits ~~i.e., the applicable emission limits listed in~~ **~~AQ-4~~**. Cold startup ~~is defined as~~**means** a startup when the ~~CTG~~**power block** has not been in operation during the preceding ~~continuous 48~~**72** hours~~, although a startup after an aborted partial cold start(a cold start that does not reach 85% output) is still considered a cold start~~. Hot~~/warm~~ startup ~~is defined as~~**means** a startup ~~that is not a cold startup~~**when the power block has been in operation during**

the preceding 8 hours. **Warm startup means a startup that is not hot or cold startup.** Shutdown ~~is~~**shall be** defined as the period beginning with the lowering of ~~equipment~~**the power block** from ~~base load~~**normal operating load** and lasting until fuel flow is completely off and combustion has ceased.

~~b. Transient conditions shall not exceed the following durations:~~

~~i. Cold startup – 180 minutes~~

~~ii. Hot/warm startup – 60 minutes~~

~~iii. Shutdown – 60 minutes~~

~~c~~**b**. During a cold startup emissions shall not exceed the following, verified by CEMS:

i. NOx – ~~120.9~~**187.5** lb

ii. CO – ~~140.4~~**134.0** lb

~~d~~**c**. During **a** ~~hot/~~warm startup emissions shall not exceed the following, verified by CEMS:

i. NOx – ~~81.9~~**154.7** lb

ii. CO – ~~58.5~~**135.3** lb

d. During a hot startup emissions shall not exceed the following, verified by CEMS:

i. NOx – 113.9 lb

ii. CO – 133.3 lb

e. During a shutdown emissions shall not exceed the following, verified by CEMS:

i. NOx – ~~29.7~~**24.8** lb

ii. CO – ~~25.3~~**148.11** 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~~7 Emissions from this ~~facility~~**equipment**, including the duct burners ~~and cooling towers~~, shall not exceed the following emission limits, based on a calendar day summary:

a. NOx – ~~1168~~**880.0** lb/day, verified by CEMS~~, compliance tests, hours of operation and/or fuel use as applicable~~.

b. CO – ~~892~~**887.4** lb/day, verified by CEMS~~, compliance tests, hours of operation and/or fuel use as applicable~~.

c. VOC as CH4 – ~~499~~**281.1** lb/day, verified by compliance tests~~,~~ and hours of operation~~ in mode~~

d. SOx as SO_2 – ~~154~~**117.6** lb/day, verified by fuel sulfur content and fuel use data.

e. PM_{10} – ~~380~~**238.2** 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, auxiliary equipment, engine, and cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:~~

~~a. NOx – 169.4 tons/year, verified by CEMS, compliance tests, hours of operation and/or fuel use as applicable.~~

~~b. CO – 110.7 tons/year, verified by CEMS, compliance tests, hours of operation and/or fuel use as applicable.~~

~~c. VOC as CH4 – 51. tons/year, verified by compliance tests and hours of operation in mode~~

~~d. SOx as SO2 – 13. tons/year, verified by fuel sulfur content and fuel use data~~

~~e. PM10 – 60.9 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. (Rule 401 – *Visible Emissions*)

Verification: The project owner shall make the site available for inspection by representatives of the District, ~~C~~ARB and **Energy** Commission upon request.

AQ-9 This equipment shall exhaust through a stack at a minimum height of ~~130~~**140** feet.

Verification: At least 60 days prior to stack fabrication the project owner shall provide to the District and the CPM drawings of the stack or other suitable proof of the minimum stack height.

AQ-10 **Except during the commissioning period as defined,** ~~The~~**the** project owner shall not operate this equipment ~~after the initial commissioning period~~ without the ~~oxidation catalyst with valid District permit C00nnnn and~~ selective catalytic **NOx** reduction system with valid District permits~~' C00nnnn#~~ **CXXXXX** installed **and fully functional**.

Verification: The project owner shall make the site available for inspection by representatives of the District, ~~C~~ARB and the **Energy** 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:** At least 60 days prior to stack fabrication the project owner shall provide to the District and the CPM drawings of the stack or other suitable documentation of the correct and complete installation of all necessary sampling ports and access platforms.~~

AQ-~~12~~11 Emissions of NOx, CO, **CO_2,** 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, ~~40 CFR 60 and/or 40 CFR 75 as applicable. Note; Where 40 CFR 60 and 40 CFR 75 are applicable but inconsistent, 40 CFR 75 shall take precedent.~~ **and they shall be installed prior to initial equipment startup. The continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the accuracy requirement for startups and shutdowns specified in Condition AQ-15. If accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits in this permit. Six (6) months prior to installation the operator shall submit a monitoring plan for District review and approval.**

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, ~~C~~ARB and the **<u>Energy</u>** Commission.

AQ-~~13~~<u>12</u> The project owner shall conduct all required compliance/certification tests in accordance with a District-approved test plan. Thirty (30) days prior to the compliance/certification tests the project owner shall provide a written test plan for District review and approval. Written notice of the compliance/certification test shall be provided to the District 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 within forty-five (45) days after testing.

Verification: Thirty (30) days prior to the compliance/certification tests, the project owner shall provide the District and CPM test plan, including test dates. Documentation of the District's approval of the test plan should be provided to the CPM 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. 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~~<u>13</u> The project owner shall perform the following annual compliance tests in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. The following compliance tests are required~~ at full load~~:

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 SO_2 in ppmvd at 15% oxygen and lb/hr~~ (measured per USEPA Reference method 6 or equivalent)~~.

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

e. PM_{10} in mg/m^3 at 15% oxygen and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).

f. Flue gas flow rate in **<u>scfmd</u>**~~dscf per minute (measured per USEPA Reference Methods 1 and 2).~~

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

h. Ammonia slip in ppmvd at 15% oxygen.

Verification: The project owner shall notify the District and CPM at least 30 days prior to annual source tests. 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~~<u>14</u> 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~~**<u>Quantification</u>** of ~~cold~~**<u>all</u>** startup VOC emissions **<u>– pursuant to a written District approved protocol and testing schedule</u>**;

b. ~~Characterization of hot/warm startup VOC emissions; and~~

~~c.~~ ~~Characterization~~**<u>Quantification</u>** of shutdown VOC emissions.

Verification: Each annual source test report (**AQ-~~14~~<u>13</u>**) shall either include the results of these tests for the current year or document the date and results of the most recent tests.

AQ-~~16~~<u>15</u> Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B ~~(or otherwise District approved)~~:

a. For NOx, Performance Specification 2.

b. For O_2, 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, ~~C~~ARB and the **<u>Energy</u>** Commission.

AQ-~~17~~<u>16</u> 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 and current 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), ~~duct burner operation time (hours),~~ number of startups, hours in cold startup, hours in ~~hot/~~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 ~~monthly~~**quarterly**, and ~~cumulative~~**total** 12-month **rolling average** 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 KKKK)**.

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).

k. Written results of annual performance tests performed.

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

AQ-~~18~~17 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~~**project owner** shall obtain ~~169.4202~~**85.6** tons of NOx~~, 51.9 tons of VOC, 47 tons of SOx,~~ and ~~60.9 tons of PM10~~**23.3 tons of VOC** offsets.

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

AQ-~~19~~18 During an initial commissioning period **not to exceed 1,250 hours and a maximum** of ~~no more than~~ 180 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:** At the end of the initial commissioning period and as needed after major maintenance, the project owner shall submit a detailed record of all commissioning and tuning activities to the CPM in the Quarterly Operational Report (**AQ-SC7**).~~

~~**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 concentration limit of **AQ-4** above and ammonia concentration limits of **AQ-4** of the SCR system shall apply coincident with the steady state operation of the SCR systems.~~

~~**Verification:** At the end of During the initial commissioning period and as needed after major maintenance, the project owner shall submit a detailed record of all commissioning and tuning activities to the CPM in the Quarterly Operational Report (**AQ-SC7**).~~

~~**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 734350 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-19 Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the gas turbine and associated electrical delivery 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-20 The commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial source testing, completed final plant tuning, and is available for commercial operation. Within 15 days of the conclusion of the commissioning period, the facility shall notify the District in writing of the date that the commissioning period ended and the actual number of hours that comprised the 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-~~24~~21 During the ~~initial~~ commissioning period, ~~emissions~~ **the emission rates** from ~~this facility~~**the gas turbine system** shall not exceed **any of** the following ~~emission~~ limits ~~(verified by CEMS)~~:

a. NOx **(as NO_2)** ~~– 25.5 tons, and 193.5 pounds/hour/CTG~~**625 lb/hr and 15,610 lb/day;**

b. ~~CO – 203.5 tons, and 2713.0 pounds/hour/CTG~~**VOC (as CH_4) - 464 lb/hr and 2620 lb/day;**

c. CO – 4,919 lb/hr and 28,500 lb/day;

d. PM10 – 8 lb/hr and 211 lb/day; or

e. SOx (as SO2) – 4.9 lb/hr and 118 lb/day

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 DELETED; Order 12-0425-3a**~~

AQ-22 During the commissioning period, NOx and CO emissions rate shall be monitored using installed and calibrated CEMS.

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-23 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: The project owner shall make the site available for inspection by representatives of the District, ARB, EPA and the Energy Commission.

AQ-~~26~~24 Within 60 days after achieving the maximum firing rate at which the facility would be operated, but not later than 180 days after initial startup, the ~~operator~~**project owner** 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~~25 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 if required by the District:~~

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 hot/warm startup VOC emissions; and~~

~~f. Characterization of shutdown VOC emissions.~~

Verification: The results of the initial compliance test (see **AQ-~~26~~24**) and a supplemental health risk analysis shall be submitted to the District and the CPM within forty-five (45) days after testing.

AQ-26 Initial compliance testing to measure startup and shutdown VOC mass emission rates shall be conducted before the end of the commissioning period and at least once every five years thereafter. The initial compliance tests shall include tests for the following:

a. Quantification of all startup VOC emissions – pursuant to a written District approved protocol and testing schedule;

b. Quantification of shutdown VOC emissions.

CEMS accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with a test protocol approved by the District. If the CEM data is not able to accurately determine compliance with NOx and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO source test demonstrates that the CEM data is accurate, the startup and shutdown NOx and CO testing frequency shall return to the once every five years schedule.

Verification: The results of the initial compliance test (see AQ-24) and a supplemental health risk analysis shall be submitted to the District and the CPM within forty-five (45) days after testing.

AQ-27 This equipment is subject to 40 CFR 60 Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units. Carbon dioxide emissions from this turbine shall not exceed 1,000 lb CO_2/MWh (gross) or 1,030 lb CO_2/MWh (net).

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, EPA and the Energy Commission.

AQ-28 Emissions from all permitted equipment at the Sonoran Energy Project, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. **NOx – 85.6 tons/year, verified by CEMS data, compliance testing and District approved methodology;**
b. **CO - 78 tons/year, verified by CEMS data, compliance testing and District approved methodology;**
c. **VOC as CH_4 – 24.3 tons/year, verified by compliance tests and hours of operation in steady-state, pre-mix mode;**
d. **SOx as SO_2 – 12 tons/year, verified by fuel sulfur content and fuel use data;**
e. **PM10 – 40.1 tons/year, verified by compliance tests and hours of operation.**

These limits shall apply to all emissions from all Sonoran Energy Project permit units at this facility, and shall include emissions during all modes of operation, including startup, shutdown and malfunction.

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

AQ-29 Pursuant to Regulation XIII the Blythe Energy Project and Sonoran Energy Project are one stationary source. Emissions from all permit units at the Blythe Energy Project and Sonoran Energy Project facilities, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. **NOx – 182.6 tons/year, verified by CEMS data, compliance testing and District approved methodology;**
b. **CO - 175 tons/year, verified by CEMS data, compliance testing and District approved methodology;**
c. **VOC as CH_4 – 48.3 tons/year, verified by compliance tests and hours of operation in steady-state, pre-mix mode;**
d. **SOx as SO_2 – 20.8 tons/year, verified by fuel sulfur content and fuel use data;**
e. **PM10 – 97 tons/year, verified by compliance tests and hours of operation.**

These limits shall apply to all emissions from all Blythe Energy Project and Sonoran Energy Project permit units at this facility, and shall include emissions during all modes of operation, including startup, shutdown and malfunction.

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

AQ-30 Total fuel use in the gas turbine and associated duct burner shall not exceed 23,984 MMscf in any rolling 12-month period.

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

~~**AQ-28 DELETED; Order 12-0425-3a**~~

~~**AQ-29** This unit shall emit no more than 0.25 pounds/hour of formaldehyde (measured per California Air Resources Board Method 430) at full load.~~

~~**Verification:** The results of the initial compliance test (see **AQ-26**) and a supplemental health risk analysis (see **AQ-27**) shall be submitted to the District and the CPM within forty-five (45) days after testing.~~

~~**AQ-30** Total emissions of Hazardous Air Pollutants or HAP (as defined in Rule 1320) from this facility shall not exceed 10 tons per year for any single HAP and 25 tons per year for any combination of HAPs, calculated on a rolling twelve month basis.~~

~~**Verification:** The project owner shall submit in the health risk analysis (**AQ-27**) the information and a rolling 12 month summary of emissions demonstrating compliance with these limits.~~

HRSG Duct Burner Conditions

~~Two (2) Individual~~ 221.6 MMBTU/HR Natural Gas Fired Heat Recovery Steam Generator Duct Burners

[MDAQMD Permit Numbers: ~~B008879 AND B008880~~BXXXXX]

AQ-31 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-32 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 twenty-four hour basis and not exceeding 0.25 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 make the site available for inspection by representatives of the District, ~~C~~ARB, 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-33 The duct burner shall not be operated unless the combustion turbine generator with valid District permit ~~# B08877 or B08878~~**BXXXXX,** ~~and~~ selective catalytic ~~NOx~~ reduction system with valid District permit ~~# C008881 or C008882~~**CXXXXX and oxidation catalyst with valid District permit CXXXXX,** 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 DELETED; Order 12-0425-3a**~~

~~**AQ-34** This equipment shall not be operated for more than 2200 hours per rolling twelve month period.~~

~~**Verification:** The project owner shall maintain a log of the monthly hours of operation for this equipment. 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-~~35~~34 ~~Monthly hours of operation for~~**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 and **Energy** Commission personnel upon request.

Selective Catalytic NOx Reduction System Conditions

~~**[TWO (2) Individual SCR Systems]**~~

[MDAQMD Permit Numbers: ~~C008881 and C008882~~CXXXXX]

AQ-~~36~~35 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.

AQ-~~37~~36 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-~~38~~37 This equipment shall be operated concurrently with the combustion turbine generator with valid MDAQMD permit ~~# B008877 or B008878~~**BXXXXX**.

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

AQ-~~39~~38 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, shutdown, and malfunction, ammonia slip shall not exceed 5 ppmvd (corrected to 15% oxygen), averaged over three hours **verified by CEMS**.

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 **Energy** Commission personnel upon request.

AQ-~~40~~39 The project owner shall record and maintain for this equipment the following on site for a minimum of five (5) years and shall be provided to District personnel upon request.

a. Ammonia injection, in pounds per hour

b. Temperature, in degrees Fahrenheit.

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 **Energy** Commission personnel upon request.

Oxidation Catalyst System Conditions

~~[Two (2) individual oxidation catalyst systems]~~

[MDAQMD Application Number: ~~0010949 and 0010950~~CXXXXX]

AQ-~~41~~40 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 oxidation catalyst system, manufacturer and design data.

AQ-~~42~~41 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 oxidation catalyst system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-~~43~~42 This equipment shall be operated concurrently with the combustion turbine generator with valid District permit ~~B008877 or B008878~~**BXXXXX**.

Verification: The project owner shall make the site available for inspection by representatives of the District, ~~C~~ARB and **Energy** Commission upon request.

Cooling Tower Conditions

[One Cooling Tower; MDAQMD Permit Number: ~~B008884~~BXXXXX]

AQ-~~44~~43 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~~44 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~~45 The drift rate shall not exceed 0.0005 percent with a maximum circulation rate of ~~108,000~~**129,480** gallons per minute (gpm). The maximum hourly PM10 emission rate shall not exceed ~~1.37~~**1.62** 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-46 No hexavalent chromium containing compounds shall be added to cooling tower circulating water.

Verification: Compliance documentation containing this information shall be submitted to the District and the CPM.

AQ-47 The ~~operator~~**project owner** shall perform weekly tests of the blow-down water **quality** ~~total dissolved solids (TDS)~~. ~~The average TDS shall not exceed 5050 ppm on a calendar monthly basis.~~ The ~~operator~~**project owner** shall maintain a log that contains the date and result of each blow-down water **quality** test ~~in TDS ppm,~~ 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. ~~We may want to propose monthly testing.~~

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

AQ-48 The ~~operator~~**project owner** 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~~**project owner** 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 would 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, ~~C~~ARB and the **Energy** Commission upon request.

Auxiliary Boiler Conditions

[One ~~60~~66.3 MMBtu/hr Natural Gas Fired Auxiliary Boiler]

[MDAQMD Application Number: ~~0010864~~BXXXXX]

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 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-51 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 twenty-four hour basis and not exceeding 0.25 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 make the site available for inspection by representatives of the District, ~~C~~ARB, and **Energy** Commission. A summary of significant operation and maintenance events for the auxiliary boiler shall be included in the Quarterly Operational Reports (**AQ-SC7**).

~~**AQ-46 DELETED; Order 12-0425-3a**~~

~~**AQ-47 DELETED; Order 12-0425-3a**~~

~~**AQ-48 DELETED; Order 12-0425-3a**~~

~~**AQ-49 DELETED; Order 12-0425-3a**~~

AQ-52 This equipment is subject to the Federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and ~~Db~~**Dc** (**Small** Industrial-Commercial-Institutional Steam Generating Units). **Pursuant to 40 CFR 60.48c, the project owner must maintain records of the quantity of fuel(s) delivered to this property during each calendar month. Records must be kept for a minimum of five years.**

Verification: The project owner shall submit auxiliary boiler specifications at least 30 days prior to purchasing auxiliary boiler for review and approval demonstrating that the auxiliary boiler meets NSPS emission limit requirements at the time of engine purchase.

AQ-53 **Except during start up/shut down events and the initial boiler tuning period,** ~~Emissions~~**emissions** from this equipment shall not exceed the following hourly emission limits ~~at any firing rate~~, verified by fuel use and annual compliance tests (initial compliance test with respect to VOC, SOx, and PM10):

a. NOx as NO_2 – ~~0.550~~**0.56** lb/hr (based on ~~9.0~~**7.0** ppmvd corrected to 3% O_2 and averaged over one hour)

b. CO – ~~1.853~~**2.43** lb/hr (based on 50 ppmvd corrected to 3% O_2 and averaged over one hour)

c. VOC as CH_4 – ~~0.110~~**0.28** lb/hr **(based on 10.0 ppmvd corrected to 3% O_2 and averaged over one hour)**

d. SOx as SO_2 – ~~0.141~~**0.05** lb/hr (based on 0.5 grains/100 dscf fuel sulfur)

e. PM_{10} – ~~0.270~~**0.46** lb/hr (front and back half)

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-54 This equipment shall not be operated for more than ~~1500~~**7000 total** hours **including startup/shutdown events** per rolling twelve month period. **Startup/shutdown events shall not exceed 400 hours per rolling twelve month period.**

Verification: The project owner shall maintain a log of the monthly hours of operation for this equipment. This information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and **Energy** Commission personnel upon request. A summary of operation of this equipment shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-55 During startup/shutdown events, emissions from this equipment shall not exceed the following emission rates verified by fuel use and annual compliance tests:

a. NOx as NO_2 – 1.99 lb/hr (based on 25.0 ppmvd corrected to 3% O2 and averaged over one hour)

b. CO – 12.13 lb/hr (based on 250 ppmvd corrected to 3% O2 and averaged over one hour)

c. VOC as CH_4 – 0.69 lb/hr (based on 25.0 ppmvd corrected to 3% O2 and averaged over one hour)

d. SOx as SO_2 – 0.05 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)

e. PM10 – 0.46 lb/hr (front and back half)

Verification: The project owner shall submit the above information in the Quarterly Operational Reports (AQ-SC7).

AQ-56 During initial boiler tuning period, emissions from this equipment shall not exceed the following emission rates verified by fuel use and annual compliance tests:

a. NOx as NO_2 – 7.97 lb/hr (based on 100.0 ppmvd corrected to 3% O2 and averaged over one hour)

b. CO – 12.13 lb/hr (based on 250 ppmvd corrected to 3% O2 and averaged over one hour)

c. VOC as CH_4 – 0.69 lb/hr (based on 25.0 ppmvd corrected to 3% O2 and averaged over one hour)

d. SOx as SO_2 – 0.09 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)

e. PM10 – 0.46 lb/hr (front and back half)

Verification: The project owner shall submit the above information in the Quarterly Operational Reports (AQ-SC7).

~~**AQ-55** A non-resettable four-digit (9,999) hour timer shall be installed and maintained on this unit to indicate elapsed engine operating time.~~

~~**Verification:** At least 30 days prior to the installation of the engine, the project owner shall provide the District and the CPM the specification of the hour timer. A dated photograph showing cumulative hours of operation shall be included in the Quarterly Operational Reports (**AQ-SC7**).~~

AQ-57 During the initial boiler tuning period, the owner or operator shall keep records of the natural gas fuel combusted in the boiler on daily basis.

Verification: The project owner shall submit the above information in the Quarterly Operational Reports (AQ-SC7).

AQ-~~56~~58 The project owner shall maintain an operations log for this equipment on-site and current for a minimum of five (5) years, and said log shall be provided to District personnel on request. The operations log shall include the following information at a minimum:

a. Total operation time (hours per month, by month);

b. Number of startups and shutdowns on a daily, monthly and rolling 12 month basis;

c. Maximum hourly, maximum daily, monthly and rolling 12 month fuel use;

~~b~~**d**. Maximum hourly, maximum daily, monthly, and rolling 12 month emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); and,

~~c~~**e**. Any permanent changes made to the equipment that would affect air pollutant emissions, and indicate when changes were made.

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 **Energy** Commission personnel upon request.

AQ-~~57~~59 The project owner shall perform the following annual compliance tests on this equipment in accordance with the MDAQMD Compliance Test Procedural

Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. **Alternative test methods may be used with the prior approval of the District.** The following compliance tests are required:

a. NOx as NO2 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).

b. CO in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Method 10).

Verification: The annual compliance 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-60 This boiler must be tuned up annually according to the procedures specified in 40 CFR 63.7540(a)(10).

Verification: The project owner shall submit the above information in the Quarterly Operational Reports (AQ-SC7).

Emergency Fire Pump Conditions

[~~One Emergency IC Engine Driving A Fire Pump~~238 HP US EPA Tier 3, USEPA Family Name TBD]

[MDAQMD Permit Number: ~~E008885~~EXXXXX]

~~AQ-50 DELETED; Order 12-0425-3a~~

~~AQ-51 DELETED; Order 12-0425-3a~~

~~AQ-52 DELETED; Order 12-0425-3a~~

~~AQ-53 DELETED; Order 12-0425-3a~~

~~AQ-54 DELETED; Order 12-0425-3a~~

AQ-~~58~~61 This ~~equipment~~ **certified stationary compression-ignited internal combustion engine** shall be installed, operated and maintained in strict accordance with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of **air** contaminants. Unless otherwise noted, this equipment shall also be operated in accordance with all data and specifications submitted with the application for this permit.

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-~~59~~62 This ~~unit~~**equipment** shall only be fired on ~~ultra-low sulfur diesel fuel, whose sulfur concentration is less than or equal to 0.0015% (15 ppm) on a weight per weight basis per CARB Diesel or equivalent requirements.~~ **diesel fuel that meets the following requirements, or an alternative fuel approved by the ATCM for Stationary CI Engines:**

a. Ultra-low sulfur concentration of 0.0015% (15 ppm) or less, on a weight per weight basis; and, a cetane index or aromatic content, as follows:

b. A minimum cetane index of 40; or,

c. A maximum aromatic content of 35 volume percent.

Note: Use of CARB certified ULSD fuel satisfies the requirements of subparagraph **62.b** above.

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, ~~C~~ARB and the **Energy** Commission upon request.

AQ-~~60~~63 A non-resettable four-digit (9,999) hour timer shall be installed and maintained on this unit to indicate elapsed engine operating time.

Verification: At least 30 days prior to the installation of the engine, the project owner shall provide the District and the CPM the specification of the hour timer. A dated photograph showing cumulative hours of operation shall be included in the Quarterly Operational Reports (**AQ-SC7**).

AQ-~~61~~64 This ~~unit~~**engine** shall be limited to emergency ~~use~~**power,** defined as **in response to a fire or flood.** ~~the pumping of water for fire suppression or protection or the pumping of water to maintain pressure in the water distribution system due to a high demand on the water supply system due to high use of water for fire suppression.~~ In addition, this ~~unit~~**engine** shall be operated no more than 50 hours per year for testing and maintenance**, unless NFPA 25 (current edition) authorizes additional time: If the 50 hour limit is exceeded, the project owner is to have the authorizing section of NFA 25 available for review at all times.** ~~including requirements pursuant to the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition.~~

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

AQ-~~62~~65 The project owner shall maintain an operations log for this unit current and on-site, either at the engine location or at an on-site location, for a minimum of five (5) years, and be made available to the District staff within 5 working days from the District's request, and this log shall be provided to District, State and Federal personnel upon request. The log shall include, at a minimum, the information specified below:

a. Date of each use and duration of each use (in hours);

b. Reason for use (testing & maintenance, emergency, required emission testing);

c. Calendar year operation in terms of fuel consumption (in gallons) and total hours; and,

d. Fuel sulfur concentration (the ~~o/o~~**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, ~~C~~ARB and the **Energy** Commission upon request.

AQ-~~63~~66 This equipment shall exhaust through a stack at a minimum height of ~~30~~**10** feet.

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the District, ~~C~~ARB, and the Energy Commission.

~~**AQ-64** This equipment shall not be tested during periods of startup of the combustion turbine generators.~~

~~**Verification:** The project owner shall make the site available for inspection of records and equipment by representatives of the District, CARB, and the Energy Commission.~~

AQ-67 This ~~unit~~**engine** is subject to the requirements of **Title 17 CCR 93115,** the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines ~~(Title 17 CCR 93115)~~ **and 40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (NSPS)**. In the event of conflict between these conditions and the ATCM **or NSPS**, the more stringent requirements shall govern.

Verification: The project owner shall submit the engine specifications at least 30 days prior to purchasing the engines for review and approval demonstrating that the engines meet ATCM emission limit requirements at the time of engine purchase.

AQ-68 The facility must submit accurate emissions inventory data to the District, in a format approved by the District, upon District request.

Verification: The project owner shall make emissions inventory data available for inspection by representatives of the District, ARB and the Energy Commission upon request.

REFERENCES

ARB 2016a. Air Designation Maps available on ARB website. http://www.arb.ca.gov/desig/adm/adm.htm. Accessed 2016.

ARB 2016b. California Ambient Air Quality Data Statistics available on ARB website. http://www.arb.ca.gov/adam/welcome.html. Accessed 2016.

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ASE2015m. Sonoran Energy Project Preliminary Determination of Compliance (TN 207175). Docketed on 12/18/2015.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2012a. California Energy Commission. 2009 Petition to Amend – Staff Analysis (TN 60499). Docketed on 3/12/2012.

U.S.EPA 2016a. The Green Book Nonattainment Areas for Criteria Pollutants. http://www.epa.gov/oar/oaqps/greenbk/index.html. Accessed 2016.

U.S.EPA 2016b. AirData database ambient air quality data. http://www.epa.gov/aqspubl1/annual_summary.html. Accessed 2016.

AIR QUALITY APPENDIX AIR-1
GREENHOUSE GAS EMISSIONS

Tao Jiang, Ph.D., P.E. and David Vidaver

SUMMARY

The SEP project is a proposed addition to the state's electricity system that would produce greenhouse gas (GHG) emissions while generating electricity for California consumers. The proposed SEP would be a nominally rated 553 megawatt (MW) combined cycle facility. Its addition to the system would displace other less efficient, higher GHG-emitting generation and facilitate the integration of renewable resources. Because the project would improve the efficiency of existing system resources, the addition of SEP would contribute to a reduction of the California GHG emissions and GHG emission rate average. The relative efficiency of the SEP project and the system build-out of renewable resources in California would result in a net cumulative reduction of GHG emissions from new and existing fossil sources of electricity.

Electricity is produced by operation of an interconnected system of generation sources. Operation of one power plant, like the SEP project, affects all other power plants in the interconnected system. The operation of the SEP project would affect the overall electricity system operation and GHG emissions as follows:

- When dispatched,[1] SEP would displace less efficient (and thus higher GHG-emitting) generation. Because the project's GHG emissions per megawatt-hour (MWh) would be lower than those of other power plants that the project would displace, the addition of SEP would contribute to a reduction of California and overall Western Electricity Coordinating Council system GHG[2] emissions and GHG emission rate average.
- SEP would provide dispatchable, flexible generation necessary to integrate the large amounts of intermittent renewable generation (also known as "variable energy resources") expected to meet the state's renewable portfolio standard (RPS) and GHG emission reduction targets.

CONCLUSIONS

The SEP project, as an addition to the California electricity system, would be an efficient, new, dispatchable natural gas-fired turbine power plant that would cause GHG emissions while generating electricity for California consumers. The project's GHG emissions per MWh would be lower than those of other power plants that the project would displace and, thus, would contribute to continued improvement of the California

[1] The entity responsible for balancing a region's electrical load and generation will "dispatch" or call on the operation of generation facilities. The "dispatch order" is generally dictated by the facility's electricity production cost, efficiency, location or contractual obligations.
[2] Fuel-use closely correlates to the efficiency of and carbon dioxide (CO_2) emissions from natural gas-fired power plants. And since CO_2 emissions from combustion dominate greenhouse gas (GHG) emissions from power plants, the terms CO_2 and GHG are used interchangeably in this section.

and overall Western Electricity Coordinating Council system greenhouse gas (GHG) emissions and GHG emission rate average. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions from the state's power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant.

Staff notes that mandatory reporting of GHG emissions per federal government and Air Resources Board (ARB) greenhouse gas regulations would occur, and these reports would enable these agencies to gather the information needed to regulate the SEP project in GHG trading markets, such as those that are expected to be required by the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.). The project may be subject to additional reporting requirements and GHG reduction and trading requirements as these regulations are more fully developed and implemented.

Staff does not believe that the minor GHG emission increases from construction activities would be significant for several reasons. First, construction emissions would be short-term, intermittent and not continue during the life of the project. Additionally, the control measures or best practices that staff recommends such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize greenhouse gas emissions. Staff believes that the use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that could be part of the ARB regulations to reduce GHG from construction vehicles and equipment. For all these reasons, staff concludes that the minor short-term emission of greenhouse gases during construction would be sufficiently reduced and would, therefore, not be significant.

The SEP project as currently proposed would emit 0.35 metric tonnes CO_2 per gross megawatt-hour or 0.36 metric tonnes CO_2 per net megawatt-hour. The project would meet the Greenhouse Gases Emission Performance Standard of 0.5 $MTCO_2$/MWh (Title 20, California Code of Regulations, section 2900 et seq.) that applies to utility purchases of base load power from power plants, should the SEP facility sell its power to a California electric utility. Any utility that enters into a contract with the SEP project would be required to seek a finding that the project meets the EPS based on the operation of the project at that time, under a proposed Power Purchase Agreement (PPA), and any other conditions that dictate the operation of the project. The SEP is also expected to comply with the federal Standards of Performance for Greenhouse Gas Emissions (or Clean Air Act section 111[b]) of 1,000 pounds of carbon dioxide per gross megawatt hour (lb CO2/MWh, gross) or (1,030 lb CO2/ MWh, net) for based load natural gas fueled turbines.

The SEP project would be consistent with the conditions in the precedent decision regarding GHG emissions established by the Avenal Energy Project's Final Energy Commission Decision (not increase the overall system heat rate for natural gas plants, not interfere with generation from existing or new renewable facilities, and ensure a reduction of system-wide GHG emissions).

AIR QUALITY GHG ANALYSIS

Tao Jiang, Ph.D., P.E.

INTRODUCTION

GHG emissions are not criteria pollutants; they are discussed in the context of cumulative impacts. In December 2009, the U.S. Environmental Protection Agency (U.S. EPA) declared that greenhouse gases (GHGs) threaten the public health and welfare of the American people (the so-called “endangerment finding”), and this became effective on January 14, 2010.

Federal rules that became effective December 29, 2009 (40 CFR 98) require federal reporting of GHGs. As federal rulemaking evolves, staff at this time focuses on analyzing the ability of the project to comply with existing federal- and State-level policies and programs for GHGs. The State has demonstrated a clear willingness to address global climate change though research, adaptation,[3] and GHG inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

Generation of electricity using any fossil fuel, including natural gas, can produce greenhouse gases along with the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. For fossil fuel-fired power plants, the GHG emissions include primarily carbon dioxide, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused or recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials.

Global warming potential is a relative measure, compared to carbon dioxide, of a compound’s residence time in the atmosphere and ability to warm the planet. Mass emissions of GHGs are converted into carbon dioxide equivalent (CO_2e) metric tonnes (MT) for ease of comparison.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

The following federal, state, and local laws and policies in **Greenhouse Gas Table 1** pertain to the control and mitigation of greenhouse gas emissions. Staff’s analysis examines the project’s compliance with these requirements.

[3] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state’s climate (for example, changing rainfall patterns).

Greenhouse Gas Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law or Regulation	Description
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule “tailors” GHG emissions to PSD and Title V permitting applicability criteria.
40 Code of Federal Regulations (CFR) Parts 51 and 52	A new stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) is also considered to be a major stationary source subject to Prevention of Significant Determination (PSD) requirements. As of June 23, 2014 the US Supreme Court has invalidated this requirement as a sole PSD permitting trigger. However, for permits issued on or after July 1, 2011 PSD applies to GHGs if the source is otherwise subject to PSD (for another regulated NSR pollutant) and the source has a GHG potential to emit (PTE) equal to or greater than 75,000 TPY CO2e.
40 Code of Federal Regulations (CFR) Parts 60, 70, 71 and 98	On August 3, 2015 EPA finalized a rule that would limit carbon dioxide emissions from new, modified and reconstructed stationary turbines. The rule became effective on October 23, 2015.
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards to reduce GHG emission to 1990 levels by 2020. Electricity production facilities are included. A cap-and-trade program became active in January 2012, with enforcement beginning in January 2013. Cap-and-trade is expected to achieve approximately 20 percent of the GHG reductions expected under AB 32 by 2020.
California Code of Regulations, Title 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
Title 20, California Code of Regulations, Section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 $MTCO_2$/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh).

AIR QUALITY GHG ANALYSIS

California is actively pursuing policies to reduce GHG emissions that include adding low-GHG emitting renewable electricity generation resources to the system. The GHGs evaluated in this analysis include carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFC), and perfluorocarbons (PFC). CO_2 emissions are far and away the most common of these emissions; as a result, even though the other GHGs may have a greater impact on climate change on a per-unit basis due to their greater global warming potential as described more fully below, GHG emissions are often "normalized" in terms of metric tons of CO_2-equivalent (MTCO2E) for simplicity. Global warming potential (GWP) is a relative measure, compared to carbon dioxide, of a compound's ability to warm the planet, taking into account each compound's expected residence time in the atmosphere. By convention, carbon dioxide is assigned a global warming potential of one. In comparison, for example methane has a GWP of 25 (Federal Register, November 29, 2013),[4] which means that it has a global warming effect 25 times greater than carbon dioxide on an equal-mass basis. The carbon dioxide equivalent (CO2E) for a source is obtained by multiplying each GHG by its GWP and then adding the results together to obtain a single, combined emission rate representing all GHGs in terms of CO2E.

GHG emissions are not included in the class of pollutants traditionally called "criteria pollutants." Since the impact of the GHG emissions from a power plant's operation has global rather than local effects, those impacts should be assessed not only by analysis of the plant's emissions, but also in the context of the operation of the entire electricity system of which the plant is an integrated part. Furthermore, the impact of the GHG emissions from a power plant's operation should be analyzed in the context of applicable GHG laws and policies, especially Assembly Bill (AB) 32, California's Global Warming Solutions Act of 2006.

GLOBAL CLIMATE CHANGE AND CALIFORNIA

Worldwide, with the exception of 1998, over the past 134-year record the 11 warmest years all have occurred since 2002, with the two hottest years on record being 2010 and 2005 (NCDC 2016). According to "The Future Is Now: An Update on Climate Change Science Impacts and Response Options for California," an Energy Commission document, the American West is heating up faster than other regions of the United States (CEC 2009c). The California Climate Change Center (CCCC) reports that, by the end of this century, average global surface temperatures could rise by 4.7°F to 10.5°F due to increased GHG emissions.

The accumulation of GHGs in the atmosphere regulates the earth's temperature. Without these natural GHGs, the earth's surface would be approximately 61°F (34°C) cooler (CalEPA 2006); however, emissions from fossil fuel combustion for activities such as electricity production and vehicular transportation have elevated the concentration of GHGs in the atmosphere above natural levels. ARB estimated that the

[4] Updated global warming potential values became effective January 1, 2014.

mobile source sector accounted for approximately 37 percent of the GHG emissions generated in California from 2009 through 2012, while the electricity generating sector accounted for approximately 20 to 22 percent of the 2009 to 2012 California GHG emissions inventory with just more than half of that on average from in-state generation sources (ARB 2014).

The Fourth U.S. Climate Action Report concluded, in assessing current trends, that CO_2 emissions increased by 20 percent from 1990 to 2004, while methane and nitrous oxide emissions decreased by 10 percent and 2 percent, respectively. The Intergovernmental Panel on Climate Change (IPCC) constructed several emission trajectories of GHGs needed to stabilize global temperatures and climate change impacts. It concluded that stabilization of GHGs at 450 ppm carbon dioxide equivalent concentration is required to keep the global mean warming increase below 3.8°F (2.1°C) from year 2000 base line levels (IPCC 2007a).

GHGs differ from criteria pollutants in that GHG emissions from a specific project do not cause direct adverse localized human health effects. Rather, the direct environmental effect of GHG emissions is the cumulative effect of an overall increase in global temperatures, which in turn has numerous indirect effects on the environment and humans. The impacts of climate change include potential physical, economic and social effects. These effects could include inundation of settled areas near the coast from rises in sea level associated with melting of land-based glacial ice sheets, exposure to more frequent and powerful climate events, and changes in suitability of certain areas for agriculture, reduction in Arctic sea ice, thawing permafrost, later freezing and earlier break-up of ice on rivers and lakes, a lengthened growing season, shifts in plant and animal ranges, earlier flowering of trees, and a substantial reduction in winter snowpack (IPCC 2007b). For example, current estimates include a 70 to 90 percent reduction in snow pack in the Sierra Nevada mountain range. Current data suggests that in the next 25 years, in every season of the year, California could experience unprecedented heat, longer and more extreme heat waves, greater intensity and frequency of heat waves, and longer dry periods. More specifically, the CCCC predicted that California could witness the following events (CCCC 2006):

- Temperature rises between 3 and 10.5 ºF;
- 6 to 20 inches or greater rise in sea level;
- 2 to 4 times as many heat-wave days in major urban centers;
- 2 to 6 times as many heat-related deaths in major urban centers;
- 1 to 1.5 times more critically dry years;
- Losses to mountaintop snowpack and water supply (e.g., according to the CCCC, Sierra Nevada snowpack could be reduced by as much as 70 to 90 percent by 2100 [CEC 2009c]);
- 25 to 85 percent increase in days conducive to ozone formation;
- 3 to 20 percent increase in electricity demand; and

- 10 to 55 percent increase in the risk of wildfires.

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps substantially) to that change. Man-made emissions of GHGs, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature found that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Cal. Health & Safety Code, sec. 38500, division 25.5, part 1).

The state has demonstrated a clear willingness to address global climate change (GCC) through research, adaptation, and GHG emission reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation (see **CALIFORNIA ELECTRICITY AND GREENHOUSE GASES** below), and describes the applicable GHG policies and programs.

In April 2007, the U.S. Supreme Court held that GHG emissions are pollutants within the meaning of the Clean Air Act (CAA). In reaching its decision, the Court also acknowledged that climate change results, in part, from anthropogenic causes (Massachusetts et al. v. Environmental Protection Agency 549 U.S. 497, 2007). The Supreme Court's ruling paved the way for the regulation of GHG emissions by U.S. Environmental Protection Agency (U.S. EPA) under the CAA.

In response to this Supreme Court decision, on December 7, 2009 the U.S. EPA Administrator signed two distinct findings regarding GHGs under Section 202(a) of the CAA:

- Endangerment Finding: That the current and projected concentrations of the GHGs in the atmosphere threaten the public health and welfare of current and future generations; and
- Cause or Contribute Finding: That the combined emissions of GHGs from new motor vehicles and new motor vehicle engines contribute to the GHG pollution, which threatens public health and welfare.

As federal rulemaking evolves, staff at this time focuses on analyzing the ability of the project to comply with existing federal- and state-level policies and programs for GHGs. As of June 23, 2014, the US Supreme Court has validated that GHG emissions should continue to be regulated, but only for those facilities that are already regulated under Prevention of Significant Deterioration (PSD) for NSR pollutants.

In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p. 5). In 2003, the Energy Commission recommended that the state require reporting of GHGs or global climate change[5] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the ARB to adopt standards that would reduce 2020 statewide GHG emissions to 1990 levels.

AB 32 includes a number of specific requirements:

ARB shall prepare and approve a scoping plan for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases by 2020 (Health and Safety Code (HSC) §38561). The scoping plan, approved by the ARB on December 12, 2008, provides the outline for actions to reduce greenhouse gases in California. The approved scoping plan indicates how these emission reductions would be achieved from significant greenhouse gas sources via regulations, market mechanisms and other actions. In early 2014, ARB completed its five year update to the Scoping Plan, tracking progress towards the 2020 emission goals and proposing new measures as appropriate.

The adopted Scoping Plan anticipates that four-fifths of the planned reductions would come from cost-effective programs and regulations, with the remainder provided by economy-wide cap-and-trade. Measures that affect the electricity sector directly include a 33 percent Renewable Portfolio Standard, alternative transportation fuels such as vehicle and ship electrification, building energy efficiency, and combined heat and power. Most of these measures have been implemented, such as Senate Bill X1 2 (Simitian, Chapter 1, Statutes of 2011-12), which established a firm goal requiring all retail providers have 33 percent of California's electricity supplies by renewable sources by 2020.

Identify the statewide level of greenhouse gas emissions in 1990 to serve as the emissions limit to be achieved by 2020 (HSC §38550). In December 2007, the ARB approved the 2020 emission limit of 427 million metric tons of carbon dioxide equivalent (MMTCO2E) of greenhouse gases. In 2013, ARB used EPA's updated information to re-calculate that level to 431 million metric tons.

Adopt a regulation requiring the mandatory reporting of greenhouse gas emissions (HSC §38530). In December 2007, the ARB adopted a regulation requiring the largest electric power generation and industrial sources to report and verify their greenhouse gas emissions. The reporting regulation serves as a solid foundation to determine greenhouse gas emissions and track future changes in emission levels. Facilities that emit more than 25,000 metric tons per year are covered. That includes most emitting power plants of five megawatts or larger. Reported emissions from individual facilities may be found on the Mandatory Reporting website, http://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/ghg-reports.htm.

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[5] Global climate change is the result of greenhouse gases, or air emissions with global warming potentials, affecting the global energy balance and thereby the global climate of the planet. The terms greenhouse gases (GHGs) and global climate change (GCC) gases are used interchangeably.

Adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions, applicable from January 1, 2012, to December 31, 2020 (HSC §38562(c)). In 2011, the ARB adopted the cap-and-trade original regulation. The cap-and-trade program covers major sources of GHG emissions in the state such as refineries, power plants, industrial facilities, and transportation fuels. The cap-and-trade program includes an enforceable emissions cap that would decline over time. The state would distribute allowances, which are tradable permits, equal to the emissions allowed under the cap. Sources under the cap would need to surrender allowances and offsets equal to their emissions at the end of each compliance period.

Individual in-state generating facilities and the first deliverers of imported electricity are the point of regulation. They are responsible for measuring their GHG emissions using ARB and U.S. EPA regulations, and purchasing either carbon allowances or offsets to meet their emissions obligation. Third party verification is required. If facilities find that it is not economic to operate and to purchase sufficient compliance instruments to cover its GHG obligations, facilities must lower their annual energy output. Further information on cap-and-trade may be found at http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

The first mandatory compliance period[6] with cap-and-trade requirements commenced on January 1, 2012, although enforcement was delayed until January 2013.

Convene an Environmental Justice Advisory Committee (EJAC) to advise the Board in developing the Scoping Plan and any other pertinent matter in implementing AB 32 (HSC §38591). The EJAC met between 2007 and 2010, providing comments on the proposed early action measures and the development of the scoping plan, public health issues, and issues for impacted communities and cap-and-trade. To advise the ARB on the 2013 Scoping Plan Update, ARB reconvened a new EJAC on March 21, 2013. The committee met three times in 2013 and would continue to provide advice to the ARB.

It is likely that GHG reductions mandated by ARB would be non-uniform or disproportional across emitting sectors, in that most reductions would be based on cost-effectiveness (i.e., the greatest GHG reduction for the least cost). For example, ARB proposes a 40 percent reduction in statewide GHG emissions from the electricity sector even though that sector currently only produces about 20 to 22 percent of the state's GHG emissions.

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[6] A compliance period is the time frame during which the compliance obligation is calculated. The years 2013 and 2014 are known as the first compliance period and the years 2015 to 2017 are known as the second compliance period. The third compliance period is from 2018 to 2020. At the end of each compliance period each facility will be required to turn in compliance instruments, including allowances and a limited number of ARB offset credits equivalent to their total GHG emissions throughout the compliance period. (http://www.arb.ca.gov/cc/capandtrade/guidance/chapter1.pdf)

SB 1368,[7] enacted in 2006, and regulations adopted by the Energy Commission and the CPUC pursuant to that bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission Performance Standard (EPS) of 0.5 metric tonnes CO_2 per megawatt-hour[8] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 EPS applies to new California utility-owned power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California, where the power plants are "designed or intended" to operate as base load generation.[9] If a project, in state or out of state, plans to sell electricity or capacity to California utilities, those utilities would have to demonstrate that the project meets the EPS. *Base load* units are defined as units that are expected to operate at a capacity factor higher than 60 percent. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. This determination is based on capacity factors, heat rates, and corresponding emissions rates that reflect the *expected* operations of the power plant and not on full load heat rates [Chapter 11, Article 1 §2903(a)].

SEP would be required to participate in California's GHG cap-and-trade program. This cap-and-trade program is part of a broad effort by the State of California to reduce GHG emissions as required by AB 32, which is being implemented by ARB. As currently implemented, market participants such as SEP are required to report their GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing allowances from the capped market and offsets from outside the AB 32 program. As new participants enter the market and as the market cap is ratcheted down over time, GHG emission allowance and offset prices would increase encouraging innovation by market participants to reduce their GHG emissions. Thus, SEP, as a GHG cap-and-trade participant, would be consistent with California's landmark AB 32 Program, which is a statewide program coordinated with a region wide WCI program to reduce California's GHG emissions to 1990 levels by 2020.

On August 3, 2015, the U.S. EPA signed a final rule (U.S. EPA 2015) under Clean Air Act section 111(b) that would limit greenhouse gas emissions (specifically, CO_2) from new, base load natural gas fueled turbines built after January 8, 2014 (for facilities with new turbines) and June 18, 2014 (for facilities with reconstructed turbines) to 1,000 lb CO_2 per MWh, gross (or 1,030 lb CO_2 per MWh, net), expressed at three digits of precision. The rule would also apply to non-base load natural gas fueled turbines by limiting CO_2 emissions to 120 lb CO_2 per million Btus of natural gas heat input, expressed at two digits of precision.

According to the U.S. EPA final rule (U.S. EPA 2015), a "base load" natural gas fired turbine is defined as one that has a capacity factor in percentage above the lower

[7] Public Utilities Code § 8340 et seq.

[8] The Emission Performance Standard only applies to carbon dioxide and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[9] See Rule at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

heating value efficiency of the turbine, expressed as a percentage. Correspondingly, a "non-base load" natural gas fired turbine is one that has a capacity factor less than or equal to the lower heating value efficiency of the turbine, expressed as a percentage, with the value capped at 50 percent. Compliance is determined over a 12-month rolling average using a continuous emissions monitoring system or by measuring actual fuel use, including start-up, shut-down and periods of malfunction.

The BACT limit for the SEP is estimated to have an emissions rate of 793 lbs CO_2 per MWh (net), less than the allowable 1,030 lbs CO_2/MWh (net). Corresponding rates expressed in gross values are 771 lbs CO_2/MWh (gross), also less than the allowable 1,000 lbs CO_2/MWh (gross).

Also on August 3, 2015, the U.S. EPA signed a final rule under Clean Air Act section 111(d) that principally applies to existing electricity generators but may also apply to new natural gas fired turbines. This requirement may be triggered if the state chooses to meet the 111(d) requirements under a mass-based option and chooses to include both existing and new units in its plan, rather than implementing a rate-based option. States have until 2016 (with optional extensions to 2018) to choose which option to use for section 111(d), so the applicability of this requirement cannot be determined for SEP at this time. However, SEP would be required to participate in the AB32 cap-and-trade program, which imposes compliance obligations for its greenhouse gas emissions, and would likely help to ensure that the facility complies with potentially applicable section 111(d) requirements.

ELECTRICITY PROJECTED GREENHOUSE GAS EMISSIONS

While electricity use can be as simple as turning on a switch to operate a light or fan, the system to deliver the adequate and reliable electricity supply is complex and variable. It operates as an integrated whole to reliably and effectively meet demand, such that the dispatch of a new source of generation unavoidably curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[10] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

PROJECT CONSTRUCTION

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include

[10] See CEC 2009b, page 95.

greenhouse gases. Construction of the SEP project would involve 26 months of activity (not including start-up or commissioning). The project owner provided a GHG emission estimate for the entirety of the construction phase. The GHG emissions estimate, presented below in **Greenhouse Gas Table 2**, includes the total emissions for the 26 months of construction activity in terms of CO_2-equivalent. The term CO2E represents the total GHG emissions after weighting by the appropriate global warming potential.

Greenhouse Gas Table 2
SEP Estimated Potential Construction Greenhouse Gas Emissions (Metric Tons/yr, Rolling 12-month maximum)

Construction Source	Construction-Phase GHG Emissions (Metric Tons)			
	CO_2	CH_4	N_2O	CO_2E
Off-Road Equipment and Onsite Vehicle	2,572	0.67	0.00	2,589
Worker Travel	1,560	0.09	0.00	1,562
Delivery Truck	493	0.002	0.00	493
Haul Trick	869	0.004	0.00	869
Construction Total	**5,494**	**0.77**	**0.00**	**5,513**

Source: Appendix 3.1-C (ASE 2015a)

PROJECT OPERATIONS

The proposed SEP would be a nominal 553-megawatt (MW) combined-cycle electrical generating facility located within the City of Blythe, adjacent to the operational Blythe Energy Project (BEP). The generating facility would consist of one General Electric (GE) Frame 7HA.02 combustion turbine generator (CTG) and associated equipment. The primary sources of GHG would be the natural gas-fired combustion turbines and the auxiliary boiler. The employee and delivery traffic GHG emissions from off-site activities are negligible in comparison with the gas turbine GHG emissions.

Greenhouse Gas Table 3 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials.

The proposed project would be permitted, on an annual basis, to emit 1,344,428 metric tonnes of CO_2-equivalent per year if operated at its maximum permitted level. The SEP facility would emit at 0.35 metric tonnes CO_2 per gross megawatt-hour or 0.36 metric tonnes CO_2 per net megawatt-hour, which would meet the SB 1368 Greenhouse Gas Emission Performance Standard of 0.500 $MTCO_2$/MWh, as well as Clean Air Act section 111(b) limit of 1,000 lbs CO_2/MWh (gross).

Greenhouse Gas Table 3
SEP Estimated Potential Greenhouse Gas (GHG) Emissions

Emissions Source	Operational GHG Emissions ($MTCO_2$/yr)
CTGs/HRSGs CO_2	1,318,394
CTGs/HRSGs CH_4	24.5
CTGs/HRSGs N_2O	2.5
Auxiliary Boiler CO_2	24,610
Auxiliary Boiler CH_4	0.5
Auxiliary Boiler N_2O	0.05
Fire Pump Engine CO_2	21
Fire Pump Engine CH_4	0.001
Fire Pump Engine N_2O	0.0002
Total Project GHG Emissions ($MTCO_2E$/yr)	**1,344,428**
Estimated Annual Gross Energy Output (MWh/yr)	3,845,201
Estimated Annual Net Energy Output (MWh/yr)	3,738321
Estimated Annualized GHG Performance (MTCO2E/MWh)	**0.35 (gross) 0.36 (net)**

Sources: Table 3.1-31 (ASE 2015a)

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses the cumulative effects of GHG emissions caused by both construction and operation. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation.

CONSTRUCTION IMPACTS

Staff believes that the small GHG emission increases from construction activities would not be significant for several reasons. First, the period of construction would be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends to address criteria pollutant emissions, such as limiting idling times and requiring, as appropriate, equipment that meets the latest criteria pollutant emissions standards, would further minimize greenhouse gas emissions to the extent feasible. The use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that would likely be part of future ARB regulations to reduce GHG from construction vehicles and equipment.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

Operational impacts of the proposed project are described in detail in a later section titled "**The Impact of the Sonoran Project on GHG Emissions from the State's Electricity Sector**" since the evaluation of these effects must be done by considering the project's role(s) in the integrated electricity system. In summary, these effects include reducing the operations and greenhouse gas emissions from the older, existing power plants; potentially displacing local electricity generation; and accelerating retirements and replacements, including aging facilities and those currently using once-through cooling. Additionally, GHG emissions impacts arising from operation are mitigated through compliance with the State's cap and trade regulation, which is designed to reduce electricity sector GHG emissions over time in order to meet AB 32 statewide GHG emissions reduction goals.

CUMUMATIVE IMPACTS

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

This entire GHG assessment is a cumulative impact assessment. The project alone would not be sufficient to change global climate, but would emit greenhouse gases and therefore has been analyzed as a potential cumulative impact in the context of existing GHG regulatory requirements and GHG energy policies.

THE IMPACT OF THE SEP ON GHG EMISSIONS FROM THE STATE'S ELECTRICITY SECTOR

David Vidaver

SUMMARY

Both the development of the BEP II as approved and the SEP as now proposed would contribute to a reduction in GHG emissions from the California electricity sector, as they would displace generation by less efficient natural gas-fired resources. It is not possible to determine a priori whether the proposed, SEP would lead to a lesser or greater reduction in GHG emissions than its approved counterpart, but its greater flexibility would facilitate the integration of greater amounts of solar generation into the California electricity system.

STAFF'S FINDINGS REGARDING THE IMPACT OF BEP II ON GHG EMISSIONS

Staff previously found that the BEP II would unambiguously reduce GHG emissions from the state's electricity sector (CEC 2012a). The GHG emissions produced by a new natural gas-fired generator are not incremental to the system, but are offset by reduced emissions from generators whose output is displaced by that of the new generator. New gas-fired generators do not displace hydroelectric or nuclear generation, technologies whose variable operating costs are lower. Nor do they displace output from renewable generators, who have not only lower variable operating costs, but often have must-take contracts for their output as well, and whose energy, in aggregate, must be procured in quantities sufficient to meet the state's Renewable Portfolio Standard. The output from new natural gas-fired generators instead displaces that from less-efficient existing natural gas-fired generators, whose variable costs are higher because they combust more natural gas per unit of electricity generated, and thus produce more GHG emissions. Under some circumstances the displaced output would be that from coal-fired generators, whose GHG emissions are even higher per MWh than those from natural gas-fired generators.

IMPACT OF THE PROPOSED SEP ON GHG EMISSIONS

It follows from the previous section that development of SEP would reduce GHG emissions from the electricity sector compared to the alternative of developing neither the BEP II project as previously approved or the SEP as currently proposed.

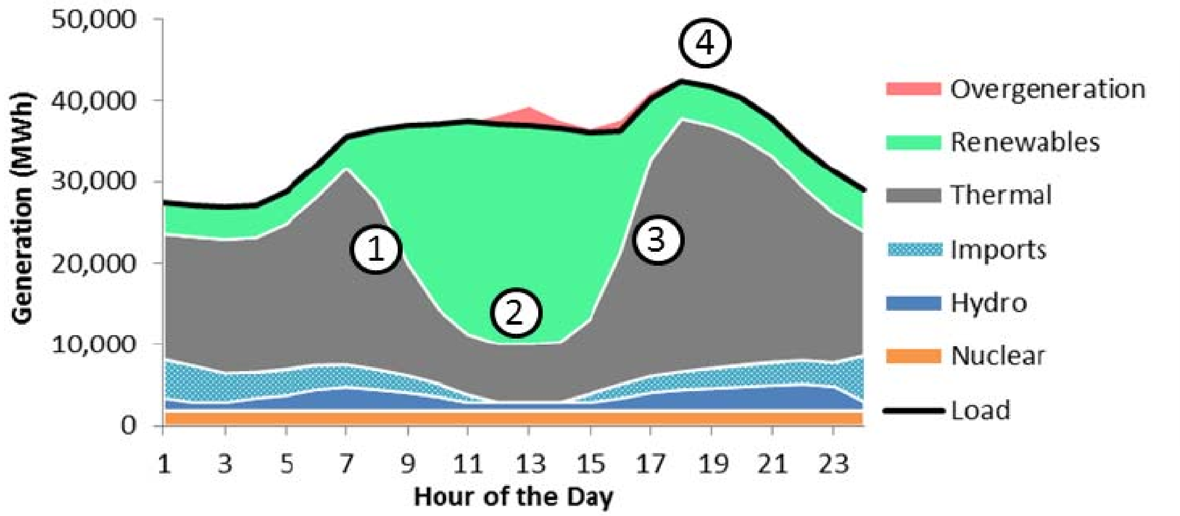
It is not possible to determine – with any accuracy - the GHG emissions that would be expected from an electricity system that includes BEP II as approved with one that includes the SEP as now proposed. While the maximum amount of natural gas that can be combusted annually under the projects' air quality and other permits provides a ceiling for the plants' CO_2-equivalent emissions, permitted levels of operation and expected operation, while related, are very different metrics.[11] More importantly, the ceiling is for GHG emissions *from the plant itself*; its consideration ignores the quantity of GHG emissions from the generators that would be displaced.

Similarly, a comparison of the thermal efficiencies of the two projects (e.g., at full load) does not provide any information regarding their expected GHG emissions or the system-wide emissions that would result from their development. While the proposed SEP has a higher thermal efficiency than the approved BEP II project at most levels of output, the differences in the efficiency and operating flexibility of the two projects mean that they would be operated differently. As such they would displace different existing generation resources, whose thermal efficiencies, and thus GHG emissions, cannot be known a priori. As a result, their relative impact on system GHG emissions cannot be known with certainty.

It is very likely, however, that SEP would lead to greater reductions in GHG emissions than its approved counterpart, as its increased flexibility (e.g., faster start-up time, ability to operate at 30 percent of full output, ability to change output by 50 MW/minute), facilitates the integration of zero-carbon variable energy resources (solar and wind) . This can be seen in **Greenhouse Gas Figure 1,** which depicts the estimated operating profile of the generating resources of the increasingly high-solar electricity system that California would develop over the next 15 years as the RPS increases to 50 percent in 2030. Much of the additional renewable energy would come from solar resources even if there is limited development of utility-scale solar generation, as the residential and commercial sectors take advantage of falling distributed solar costs, tax incentives, payments for energy remitted to the system at retail rates, and new residential construction post-2020 is required, where cost-effective, to be zero-net energy, (i.e., include solar panels).

[11] Natural gas-fired peaking facilities are usually permitted at roughly a 30 percent capacity factor, but are expected to operate in the range of two to five percent. Load following generation is permitted at a 30 to 50 percent capacity factor, but expected to operate in the 10 to 20 percent range. Finally, combined cycles have frequently permitted at close to 100 percent, but are expected to operate in the 40 to 70 percent range.

Greenhouse Gas Figure 1
California Generation Typical for a Non-Summer Day ("Duck" Chart)



Source: CA ISO 2014

The large "belly" (Number 2 in the figure) represents solar generation on a typical non-summer day; this gets larger over time as more solar is added to the system. The gray area represents necessary thermal generation, which is increasingly natural gas over time as California portfolios are divested of coal pursuant to the state's Emission Performance Standard. Note that imports are reduced to zero at midday, and hydro generation is limited to run-of-river (from hydro-generation facilities that do not have reservoir storage, and from water that must be allowed to flow due to recreational needs, flood control, habitat preservation, etc.). A large share of midday generation must also be flexible, dispatchable natural gas as: (a) a threshold amount of thermal capacity needs to be idling (or at least readily available, not unlike a hybrid car) at mid-day at minimum output to protect against sudden component failures (major power plants and transmission lines), or drops in solar output; and, (b) a large amount of gas-fired generation would be needed 4 to 8 hours later when solar energy is unavailable, and thus must be on line and generating at minimum output at mid-day.

Greenhouse Gas Figure 1 illustrates a case of over-generation; in which renewable output at mid-day and necessary gas-fired generation jointly result in too much energy being produced. There are several ways to deal with over-generation. In theory, the surplus energy can be exported to neighboring states. But much of the over-generation expected in California would occur during the low-demand months of February to April, when similar surpluses exist in the Pacific Northwest due to the snow melt and the resulting increase in hydroelectric generation in the Columbia River basin. Under these conditions, export potential is likely to be limited and export prices would be near zero.

A long-term solution for over-generation is expected to be the development of cost-effective, multi-hour storage, allowing the surplus to be stored until it can be used in evening hours. In the interim, however, over-generation can only be dealt with by curtailing renewable generation or reducing the amount of gas-fired generation that is needed during midday and early afternoon hours. The latter is facilitated by developing gas-fired resources that operate at low levels of output or cycle off during mid-day hours.[12]

[12] For a detailed discussion of the operational needs for a high-solar portfolio, see Energy and Environmental Economics, *Investigating a Higher Renewables Standard in California*, January 2014, available at http://www.ethree.com/public_projects/renewables_portfolio_standard.php.

COMPLIANCE WITH GHG LORS

Tao Jiang, Ph.D., P.E.

SEP is required to participate in California's GHG cap-and-trade program, which became active in January 2012, with enforcement beginning in January 2013. This cap-and-trade program is part of a broad effort by the State of California to reduce GHG emissions as required by AB 32, which is being implemented by ARB. As currently implemented, market participants such as SEP are required to report their GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing allowances from the capped market and offsets from outside the AB 32 program. SEP, as a GHG cap-and-trade participant, would be consistent with California's landmark AB 32 Program, which is a statewide program coordinated with a region wide WCI program to reduce California's GHG emissions to 1990 levels by 2020. ARB staff continues to develop and implement regulations to refine key elements of the GHG reduction measures to improve their linkage with other GHG reduction programs. The project may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB.

Reporting of GHG emissions would enable the project to demonstrate consistency with the policies described above and the regulations that ARB adopts and to provide the information to demonstrate compliance with any future AB 32 requirements that could be enacted in the next few years.

The SEP would emit at 0.35 MT CO_2/MWh (gross) or 0.36 MT CO_2/MWh (net), which complies with the California's SB1368 Emissions Performance Standard (EPS) limit of 1,100 lb/MWh (net). It would also comply with the federal GHG limit of 1,030 lbs CO_2/MWh (net) for base load natural gas fired turbines specified in the U.S. EPA final rule under Clean Air Act section 111(b).

The PDOC states that modeling analysis, monitoring for GHGs, and impact analysis from GHGs in the nearby Class I areas are not required for GHG PSD analysis.

PROPOSED CONDITIONS OF CERTIFICATION

One Condition of Certification (**AQ-27**) related to the greenhouse gas emissions from project operation is proposed to comply with federal GHG requirements. The project owner would also participate in California's GHG cap-and-trade program, and is required to report GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions, by purchasing allowances from the capped market and offsets from outside the AB 32 program.

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SONORAN ENERGY PROJECT (02-AFC-1C)
Petition to Amend Final Commission Decision
BIOLOGICAL RESOURCES
Andrea Martine

SUMMARY OF CONCLUSIONS

Staff concludes that the proposed Sonoran Energy Project (SEP) Petition to Amend (PTA) to the 2005 Final Commission Decision (2005 Decision) (CEC 2005) on the Blythe Energy Project, Phase II (BEP II) would potentially create new significant direct and cumulative impacts to biological resources. The Project Description section of the PTA describes discharge of 23.1 million gallons of wastewater annually to onsite evaporation ponds (5 acres total) during normal plant operations. However, the BEP II was licensed to use a zero liquid discharge (ZLD) process to avoid routinely discharging process wastewater in an evaporation pond. The Energy Commission found in the 2005 Decision that use of a ZLD system would avoid potential impacts to birds from evaporation ponds. Although the wastewater discharge described in the PTA is inconsistent with the restrictions set by Conditions of Certification **BIO-12** and **WATER QUALITY-5** in the 2005 Decision (renumbered **SOIL&WATER-4** in the **Soil & Water Resources** section of this document), the project owner has not requested revisions to or deletion of these conditions, nor any alternative measures to avoid or mitigate potentially significant impacts to migratory birds from evaporation ponds. Staff understands the project owner is currently evaluating options for wastewater discharge. Staff continues to recommend the use of ZLD to avoid impacts to migratory birds and ensure compliance with the Migratory Bird Treaty Act. Dry cooling, as proposed by Soil and Water staff, would substantially reduce the amount of SEP's wastewater. The amount of wastewater reduction and the available capacity at the existing Blythe Energy Project (BEP) ponds are factors in determining if using the existing ponds for SEP's wastewater is feasible. ZLD or other wastewater handling technologies combined with dry cooling may also be feasible options for avoiding using, or constructing new, evaporation ponds. For these reasons, the proposed amendment to the BEP II would require additional analysis and supplementation of the BEP II 2005 Commission Decision in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., titl. 14, § 15162).

Aside from the issue identified above, and the previous environmental analysis of the transmission line (gen-tie), the Committee may rely upon the analysis and conclusions of the 2005 Decision with regard to biological resources and does not need to re-analyze them. The current proposal to locate the gen-tie line north of the project site would not significantly impact biological resources. Implementation of existing Conditions of Certification **BIO-1** through **BIO-11** would mitigate potential impacts that may occur during construction of the amended project to less than significant and would ensure these activities comply with applicable laws, ordinances, regulations, and standards (LORS).

INTRODUCTION

Staff reviewed the 2005 Decision and analyzed the proposed changes to the approved BEP II, which include replacing the previously approved combustion and steam turbines with different turbines onsite, relocating the gen-tie line offsite, and using evaporation ponds for wastewater discharge rather than a ZLD system. The PTA also requests that the BEP IIname be changed to theSEP. Staff reviewed the 2005 Decision for the BEP II's previously identified impacts on biological resources since the Commission determined in its 2012 Final Decision (2012 Order) that the changes to the facility's design proposed in the 2009 amendment did not change the conclusions and findings of the 2005 Decision with respect to biological resources.

New significant impacts on biological resources would be caused by the SEP due to the use of evaporation ponds. In addition, staff has considered the potential for impacts from the relocation of the gen-tie line, which would be sited in an area that was not previously evaluated in the 2005 Decision. For these reasons, the proposed amendment to the BEP II would require additional analysis and supplementation of the BEPII 2005 Decision in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., titl. 14, § 15162).

SUMMARY OF THE COMMISSION DECISION

In its 2005 Decision, the Commission found impacts to protected species and their habitats would not be significant as a result of the project site being highly disturbed, fenced, and adjacent to the operating BEP power plant, intensive agriculture, a major interstate highway, and an airport. Under an amendment to the BEP, the BEP II site was previously graded and fenced to exclude wildlife for disposal of excess fill associated with the BEP. As part of its approval of the BEP expansion amendment, the Commission required compensation for the habitat loss at the site (CEC 2005). For BEP II, the Commission required conditions of certification (**BIO-1** through **BIO-11**) to mitigate the effects of short term construction disturbances on wildlife in the area surrounding the project site or that may gain access to the site. These conditions include requirements to retain biological resource specialists to monitor construction activities and halt those activities with the potential to harm sensitive species, implementing a worker environmental awareness program, monitoring the exclusionary fencing, and implementing avoidance and minimization measures.

As discussed in the 2005 Decision, the BEP II was originally proposed to have an evaporation pond. However, to avoid potential bird impacts the original project owner substituted the pond for a ZLD system utilizing brine crystallization technology (CEC 2005, page 53). The Commission imposed Condition of Certification **BIO-12**, which allows discharges of brine, distillate from the brine concentrator, and cooling tower blow down water to the evaporation ponds only in the cases of cooling system initial commissioning, maintenance, planned or forced outages, or emergency. A companion condition of certification, **WATER QUALITY-5** in the **Water Quality and Soils** section of the 2005 Decision (renumbered **SOIL&WATER-4** in the **Soil & Water Resources** section of this document), prohibits liquid wastewater discharge either on or off-site, with the exception of the temporary discharge of wastewater to evaporation ponds during periods of ZLD system outages. The current petition to amend proposes routine wastewater discharge to evaporation ponds (5 acres in total). Staff's analysis addresses the impacts to biological resources from using evaporation ponds.

The Commission did not find any impacts to species habitat from the project's transmission (gen-tie) line to the Buck Boulevard Substation because it would have been installed across the BEP parcel, which is industrial with no remaining wildlife habitat. In addition, the Buck Boulevard Substation, which was constructed on the BEP parcel, is fully enclosed with a desert tortoise-proof fence and contains no wildlife habitat (CEC 2005, pages 55-56). Staff's analysis addresses the current proposal to locate the gen-tie line offsite.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

No LORS applicable to the project have changed for Biological Resources since the Commission Decision was published in December 2005. Additionally, the proposed amendment would not trigger new LORS that may have not been applicable to the original project. Implementation of Conditions of Certification **BIO-1** through **BIO-11** will ensure the amended project complies with applicable LORS during construction. The use of evaporation ponds as proposed in the PTA would not comply with the Migratory Bird Treaty Act. See staff's analysis of the use of evaporation ponds, below.

ENVIRONMENTAL IMPACT ANALYSIS

Staff reviewed the proposed changes to the licensed BEP II for potential new environmental effects. Staff contacted representatives of U.S. Fish and Wildlife Service (USFWS) and California Department of Fish and Wildlife (CDFW) for their input on the changes described in the PTA. Comments were received from the USFWS and have been addressed in this analysis (Fraser, pers. comm., 2015, TN207174). The CDFW is expected to review staff's analysis and provide comments during the public review period.

Excluding the proposed evaporation ponds, the onsite changes to the licensed project would not result in new significant effects on biological resources or a substantial increase in the severity of previously identified significant effects. The proposed SEP site is currently fenced and contains fill material transferred from the BEP site. Because of the disturbance of the SEP site from the addition of fill material, the site contains very little vegetation. For these changes to the licensed project, the Committee may rely upon the analysis and conclusions of the 2005 Decision with regard to biological resources and does not need to re-analyze them. Implementation of existing Conditions of Certification **BIO-1** through **BIO-11** would mitigate potential impacts that may occur during construction of the amended project elements onsite to less than significant.

New potentially significant impacts to biological resources resulting from the use of evaporation ponds are discussed below. Staff has also included an analysis of the effects of locating the gen-tie line offsite, in an area not previously evaluated for impacts to biological resources.

EVAPORATION PONDS

As discussed in the 2005 Decision, the BEP II was originally proposed to have one evaporation pond. Project wastewater from the water treatment plant and the cooling towers would have been discharged to the ponds and allowed to evaporate unassisted. The original Final Staff Assessment (FSA) provided a detailed discussion of the impacts the proposed pond would have on avian species (CEC 2005a, pages 4.2-10 – 4.2-16). To avoid these impacts, the original project owner substituted the pond for a ZLD system utilizing brine crystallization technology (CEC 2005, page 53). The Commission imposed Condition of Certification **BIO-12**, which allows discharges of brine, distillate from the brine concentrator, and cooling tower blow down water to the evaporation ponds *only* in the cases of cooling system initial commissioning, maintenance, planned or forced outages, or emergency. A companion condition of certification, **WATER QUALITY-5** in the **Water Quality and Soils** section of the 2005 Decision (renumbered **SOIL&WATER-4** in the **Soil & Water Resources** section of this document), prohibits liquid wastewater discharge either on or off-site, with the exception of the temporary discharge of wastewater to evaporation ponds during periods of ZLD system outages. For the SEP, the project owner proposes to routinely discharge 23.1 million gallons of wastewater annually to onsite evaporation ponds (5 acres total) during normal plant operations.

As discussed in the original FSA, evaporation ponds attract birds and other wildlife (e.g. insects and bats). The water in the evaporation ponds would contain contaminants including selenium and sodium. The concentration of selenium and sodium would increase over time depending on the amount of wastewater discharged and the rate of evaporation along with fluctuating water levels. Lower water levels allow algae and invertebrates to accumulate and thus the accumulation of contaminants such as selenium occurs at a faster rate than in cooler deeper waters. It was estimated that the wastewater from the brine concentrator would have a sodium concentration of over 58,000 milligrams per liter (mg/L), nearly 1.5 times the salinity of ocean water. The wastewater would also have a high selenium concentration (1.8 mg/L) (CEC 2005, page 58). As shown in Table 2-4 of the 2015 PTA, the sodium and selenium concentrations in the wastewater discharge to the evaporation pond would be 32,842 ppm (32,842 mg/L) and 1 ppm (1 mg/L), respectively. The direct loss of birds, bats, and/or other wildlife could result from ingesting these contaminants, their concentrations in the ponds increasing over time. Most birds are protected under the Migratory Bird Treaty Act.

Beckon *et al*., 2001, indicated that selenium concentrations in water less than 2 ug/g on dry weight basis (equivalent to 2 mg/L) had no effect on fish and bird reproduction whereas selenium levels greater than 5 ug/g (5 mg/L) are considered toxic to fish and bird reproduction. However, minimum concentrations of selenium in water that are considered toxic to avian reproduction range from 2-10 ug/L (0.002 -0.01 mg/L) in

Salton Sea, California to 7.5-17.5 ug/g (0.0075-0.0175 mg/L) in Chevron Marsh, California (Bureau of Reclamation *et al.,* 1998). The bioaccumulation of selenium in invertebrates at levels greater than 7 ug/g (7 mg/L) is considered hazardous and toxic to the health, long-term survival, and reproduction of birds (Beckon *et al*., 2002), however, selenium concentration of 2.9 mg/kg dry weight (2.9 mg/L) in the food chain fauna is considered toxic to avian reproduction (Bureau of Reclamation *et al.,* 1998). Lemly (1997), determined that foodchain organisms containing more than 3 ug/g on dry weight basis (3 mg/L) or more are considered potentially lethal to fish and aquatic birds that consume them. 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).

For the original BEP II, staff concluded that the project owner must find a permanent solution that ensures birds are not exposed to toxic levels of sodium or selenium from the facility's wastewater stream. Staff's conclusion was based on the following:

- 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 (the Blythe Airport is one mile east of the project site) is discouraged by the Federal Aviation Administration (FAA, California Department of Transportation Division of Aeronautics (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 be exposed to toxic levels of selenium except from the project'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 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; and

- 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.

Hence staff recommended one of the following two alternatives:

1. Eliminate the evaporation ponds and install a 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; and
2. Filter contaminants (such a selenium) from the water. Successful systems include an Algal-Bacterial Selenium Removal Process system paired with a reverse osmosis system.

USFWS recommends that the SEP's evaporation ponds be eliminated, and instead the SEP should use the ponds installed at the BEP for wastewater discharge. Additionally, they recommend the development and implementation of a Bird and Bat Conservation Strategy (BBCS) that includes a mortality monitoring component in order to comply with the Migratory Bird Treaty Act. Condition of Certification **BIO-12** requires the project owner to implement an Evaporation Pond Mitigation and Monitoring Plan during the limited times the project as licensed was allowed to discharge wastewater to the ponds. The condition requires the project owner to monitor the ponds for bird use and take actions to avoid or discourage bird and wildlife use following any period of discharge to the ponds. Adaptive management is required if the measures taken are not effective. If the project owner revises the current amendment to include a ZLD system like the approved BEP II, there would be no new significant impacts warranting development and implementation of a BBCS. However, if evaporation ponds are used as presently described in the PTA, development of a BBCS may be one of the mitigation measures recommended by staff in this project's FSA.

Soil and Water staff is proposing dry-cooling to reduce the use of water because of the state's water policy, the unsustainable groundwater pumping, and the Energy Commission staff-prepared Water Supply Assessment, which indicates the water supply of the Palo Verde Mesa basin cannot support the SEP (see the **Soil and Water Resources** section). Using dry cooling would substantially reduce wastewater because it would eliminate discharge of blow-down water from the proposed wet cooling tower. The amount of wastewater reduction and the available capacity at the BEP ponds are factors in determining if using the existing BEP ponds for BEP II's wastewater discharge is feasible. ZLDor other wastewater handling technologies combined with dry cooling may also be feasible options for avoiding using, or constructing new, evaporation ponds.

GENERATION-TIE LINE

The proposed alignment of the 161-kV gen-tie line extends from the north side of the proposed SEP generator step-up unit transformer to the existing Buck Boulevard Substation on the existing BEP site located to the east and adjacent to the SEP site.

However, unlike the originally approved route that was entirely on the BEP and BEP II sites, PTA Figure 2-2b shows a portion of the gen-tie line located offsite on the north side of W. Chanslor Way, and extending east parallel to W. Chanslor Way for approximately 900 feet before entering the Buck substation.

Land cover types and vegetation communities present within 500 feet of the gen-tie line for the proposed SEP includes barren/disturbed, developed, and primarily disturbed Sonoran desert scrub (AltaGas Sonoran Energy Inc. 2015, 2015a, and Figure DR23-1). The area of disturbed Sonoran desert scrub habitat is relatively flat and had been used for agricultural production prior to the Energy Commission's approval of BEP. Due to the previous disturbance, there is limited potential for special-status plant or wildlife species to occur in this area.

Grading and installation of the poles associated with the construction of the gen-tie line would impact previously disturbed Sonoran desert scrub habitat. Based on preliminary engineering designs, the project owner estimates that construction activities would permanently and temporarily impact approximately 1 acre and 1.4 acres of disturbed Sonoran desert scrub habitat; respectively. Implementation of existing Conditions of Certification **BIO-1** through **BIO-11** would avoid and minimize disturbance to sensitive species that may wander into the area during construction of the gen-tie line. The relocation of the gen-tie line would have no significant impacts to biological resources.

Section 7 of the Endangered Species Act Consultation History

Consultation between Western Area Power Administration and the USFWS under Section 7 of the Endangered Species Act resulted in a Biological Opinion (BO) for the project (USFWS 2002). The BO indicated that if any additional habitat destruction or alteration occurs beyond what was covered in the BO, then re-initiation of the Section 7 consultation with USFWS would be required.

Staff contacted USFWS to determine whether relocation of the gen-tie line would require re-initiation of consultation with USFWS. The USFWS has determined that the existing consultation for the project remains relevant and the measures in the BO pertaining to avoidance and minimization of impacts to individual desert tortoises should continue to be implemented where necessary (USFWS 2015). However, USFWS recommends the use of the information in the following website for the most current guidance for desert tortoise:
http://www.fws.gov/carlsbad/PalmSprings/DesertTortoise.html.

As required by Condition of Certification **BIO-5, #3**, the avoidance and minimization measures contained in the BO must be incorporated into the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) for the project.

The USFWS expressed concerns that transmission infrastructure can have significant impacts on resident and migratory birds and recommended burying the project's gen-tie line underground, if possible (Fraser, pers. comm., 2015, TN207174).

The impact of the gen-tie line to avian species was previously analyzed for the licensed project. Condition of Certification **BIO-6, #10** requires the Gen-Tie line to be designed and installed following the Avian Power Line Interaction Committee's Guidelines (APLIC 2012). The originally licensed BEP II had a 2,500-foot long 500-kV gen-tie line to the Buck Boulevard Substation. The new approximately 1,320-foot long 161-kV gen-tie line to the Buck substation would not create new significant impacts or substantially more severe impacts to avian species than previously evaluated for the licensed BEP II.

CUMULATIVE IMPACTS

The cumulative impacts scenario has changed since the 2005 Commission Decision. Several projects have been proposed and some completed since the 2005 Decision. These projects include Devers-Palo Verde No.2, Genesis Solar Energy Project (GSEP, Docket No. 09-AFC-8C), Desert Sunlight Solar Farm, Blythe Solar Power Project (BSPP, Docket No. 09-AFC-6C), and McCoy Solar Power Project. Devers-Palo Verde No.2 is a 41.6 mile-long transmission line between the Devers substation and Southern California Edison's Valley substation. The GSEP, a 250 MW solar thermal power plant using parabolic trough technology, was approved by the Energy Commission in September 2010 and has been operational since April 2014. The GSEP has two 3.5-acre netted evaporation ponds. The 550 MW Desert Sunlight Solar Farm, a solar photovoltaic (PV) facility located in the town of Desert Center, became operational in February 2015. The BSPP is a 485 MW PV facility located west of the city of Blythe in Riverside County, California, that is currently under construction. It will have two netted 6-acre evaporation ponds. The McCoy Solar Power Project, a 750 MW solar PV facility, is also currently under construction.

There are potentially significant cumulative impacts to avian species from the collision with transmission lines, poles, and the panels and mirrors associated with these solar facilities. Evaporation ponds associated with some of these facilities serve as attractants for avian species in the desert where water is scarce and the high levels of toxic constituents in water disposed to the evaporation ponds are potentially harmful to the avian species. While mitigation measures have been proposed to reduce direct impacts to less than significant for the Devers-Palo Verde No.2, GSEP, BSPP, and McCoy Solar Power Projects, the SEP's impacts to avian species from using evaporation ponds would be cumulatively considerable as currently proposed.

The use of a ZLD system as required by the BEP II Decision would mitigate the SEP's contribution to significant cumulative impacts.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the SEP's proposed use of evaporation ponds would result in new significant direct and cumulative impacts to biological resources, impacts that the approved BEP II using ZLD technology would have avoided. Conditions of Certification **BIO-12** and **WATER QUALITY-5** (renumbered **SOIL&WATER-4** in the **Soil & Water Resources** section of this document) allow wastewater discharge to evaporation ponds only in the cases of cooling system initial commissioning and maintenance, planned or forced outages of the ZLD system, or emergencies. During these limited periods, **BIO-12** requires implementation of an Evaporation Pond Mitigation and Monitoring Plan to avoid impacts to biological resources from exposure to wastewater discharges. The use of evaporation ponds as described in the PTA is at odds with **BIO-12**, and the project owner has not proposed any alternative measures to avoid or mitigate potentially significant impacts to migratory birds. Staff understands the project owner is currently evaluating options for wastewater discharge. Staff continues to recommend the use of ZLD to avoid impacts to migratory birds and ensuring compliance with the Migratory Bird Treaty Act. Dry cooling, as proposed by Soil and Water staff, would substantially reduce the amount of SEP's wastewater. The amount of wastewater reduction and the available capacity at the existing BEP ponds are factors in determining if using the existing ponds (as recommended by USFWS) for SEP's wastewater is feasible. Zero liquid discharge or other wastewater handling technologies combined with dry cooling may also be feasible options for avoiding using, or constructing new, evaporation ponds.

Staff concludes that the new route of the gen-tie line would not disturb or impact any sensitive habitat or special-status plants or wildlife. With implementation of Conditions of Certification **BIO-1** through **BIO-11** in the 2005 Decision, impacts to sensitive biological resources during construction of the amended project would be mitigated to less than significant and ensure these activities comply with LORS.

PROPOSED CONDITIONS OF CERTIFICATION

The conditions of certification below are from the 2005 Decision. Staff has proposed minor changes to the conditions of certification. New text is shown in **<u>bold and underline</u>** and deleted text is shown as ~~strikethrough~~.

DESIGNATED BIOLOGIST <u>AND BIOLOGICAL MONITOR(S)</u> 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.

<u>The Designated Biologist must meet the following minimum qualifications:</u>

<u>1. Bachelor's Degree in biological sciences, zoology, botany, ecology, or a closely related field;</u>

<u>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</u>

3. **<u>At least one year of field experience with biological resources found in or near the project area.</u>**

<u>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 Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP).</u>

<u>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</u>

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:

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. Notify the project owner and the CPM of any non-compliance with any biological resources Condition of Certification; and
5. 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 (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, and operation are informed about sensitive biological resources associated with the project.

The WEAP must:

1. Be developed by or in consultation with the Designated Biologist and consist of an on-site or training center presentation in which supporting written material is made available to all participants;
2. Discuss the locations and types of sensitive biological resources on the project site and adjacent areas;
3. Present the reasons for protecting these resources;
4. Present the meaning of various temporary and permanent habitat protection measures;
5. Identify whom to contact if there are further comments and questions about the material discussed in the program; and
6. Include a training acknowledgment form to be signed by each worker indicating that they received training and shall abide by the guidelines.

A competent individual(s) acceptable to the Designated Biologist can administer the specific program.

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 project owner shall keep the signed training acknowledgement forms on file 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~~ **CDFW** 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 process for proposing plan modifications to the CPM and appropriate agencies for review and approval; and
16. 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~~ **CDFW**, 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~~ **CDFW**, 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~~ **CDFW**;

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~~ **CDFW, the CPM,** and the project owner shall follow instructions that are provided by ~~CDFG~~ **CDFW**. ~~.~~ 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~~ **December 2009** (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.

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.

EXOTIC WEED CONTROL PROGRAM

BIO-7 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~~ **SEP** 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: 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.

CONFINED WILDLIFE

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~~ **Wildlife and the CPM** 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(~~ie~~s) for burrowing owl activities to assess owl presence and need for further mitigation. The Designated Biologist or Biological Monitor(s) shall monitor active burrows 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. 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~~ **CDFW**-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~~ **CDFW** 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.

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~~ **CDFW**.

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 that 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 the Western Area Power Administration, U.S. Fish and Wildlife Service, California Department of Fish and ~~Game~~ **Wildlife**, and the CPM 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. Thirty (30) days prior to activity within the Cultural Resource Avoidance Area, it 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.

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~~ **Wildlife** 60 days prior to any proposed construction in the Cultural Resource Avoidance Area. 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.

EVAPORATION POND USE

BIO-12 The project owner shall discharge brine, distillate from the brine concentrator, and cooling tower blow down water to the evaporation ponds only in the cases of cooling system initial commissioning, maintenance, planned or forced outages or emergency. The project owner shall notify the CPM in case of any discharge. At the earliest opportunity, when supported by plant operations, the water shall be pumped from the evaporation ponds to the cooling tower basin, brine concentrator or brine crystallizer (as appropriate) for processing until the evaporation ponds have been emptied.

The project owner shall prepare an Evaporation Pond Mitigation and Monitoring Plan to ensure that any impacts from the discharge are mitigated. If a substantial number of bird, wildlife, or protected species are found using the ponds, then remedial actions to reduce wildlife use to a less than significant level and to prevent nesting must be implemented.

When such a discharge occurs to the evaporation pond, remedial measures shall be performed to discourage nesting and reduce bird and wildlife exposure to the ponds. The project owner shall provide notice to the CPM and submit records of all monitoring dates, data collected, and any corrective actions taken in the Evaporation Pond Monitoring Report.

After any facility closure of more than four (4) months, and at a time when the ponds do not have water in them, the ponds shall be cleaned if it is determined by the CPM the sediment presents a risk of contamination to wildlife. No clean-up of clean, untainted sediment that is windblown into the ponds is required.

The Evaporation Pond Mitigation and Monitoring Plan shall identify:

1. All biological resources to be impacted, avoided, or mitigated by evaporation pond use or closure.
2. A detailed description of all biological resources mitigation, monitoring, and compliance measures included in the Commission's Final Decision, the Federal and State Endangered Species Act, the California Environmental Quality Act, and the Migratory Bird Treaty Act;
3. A detailed description of methods to be used to avoid or discourage bird and wildlife use and to prevent nesting following any period of discharge;
4. Detailed description of remedial measures to be performed if initial methods do not meet specified condition;
5. The individual(s) who are responsible for monitoring and reporting;
6. The estimated dates of planned outages, duration, number of times per year, and volume for discharges to the evaporation ponds;
7. Monitoring frequency and dates, conditions, data collected, reporting periods, and actions to be implemented following a discharge;
8. The cleaning schedule after any discharge to the ponds;
9. Reporting procedures to be followed in the case of any unplanned or emergency discharge;
10. Methods to remove chemical residue in the ponds should a facility closure occur for more than four months; and
11. Reporting procedures following a facility closure for more than four months.

Verification: At least ninety (90) days prior to commencing construction of the evaporation ponds, the project owner shall provide two copies of the Evaporation Pond Mitigation and Monitoring Plan and all supporting materials to the CPM for review and approval.

The CPM, in consultation with the ~~CDFG~~ **<u>CDFW</u>**, USFWS, and any other appropriate agencies, will determine the plan's acceptability within forty-five (45) days of receipt, if possible. Any modifications to the plan will follow the same approval and time periods as those for the BRMIMP (**BIO-5**).

The project owner shall submit an Evaporation Pond Monitoring Report to the CPM on a quarterly basis. The Evaporation Pond Monitoring Report shall include event specific details as requested in #7 – 10 above. The monitoring shall continue for at least the first three years of power plant operation, and depending on the results, could be discontinued after written notice from the CPM, and consultation with ~~CDFG~~ **CDFW** and USFWS, if there is no evidence of significant wildlife exposure to the evaporation ponds.

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SONORAN ENERGY PROJECT (02-AFC-01C)

Petition to Amend Final Commission Decision
CULTURAL RESOURCES
Diana T. Dyste and Thomas Gates

SUMMARY OF CONCLUSIONS

Staff concludes that the proposed amendment would have no new cultural resource impacts and the mitigation for the original project would likely still be applicable and would not require any substantive changes. However, some changes to Conditions of Certification **CUL-9** and **CUL-10** may be warranted, after further consultation with tribes, Western Area Power Administration (Western), and the California Office of Historic Preservation (OHP). Staff also concludes that the findings of fact from the December 2005 Blythe Energy Project Phase II (BEP II) Commission Decision (2005 Decision) (CEC 2005b) would still apply to the amended Sonoran Energy Project (SEP). Therefore, in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that some supplementation to the 2005 Decision may be necessary for Cultural Resources. The Committee may rely upon the environmental analysis and conclusions of the 2005 Decision with regards to cultural resources and does not need to re-analyze them. However, staff will introduce additional analysis as the aforementioned consultations are concluded prior to the staff issuance of the Final Staff Assessment (FSA).

INTRODUCTION

Staff reviewed the 2005 Decision and analyzed the changes to the BEP II, which includes re-routing the electrical transmission (gen-tie) line, replacing the previously approved combustion turbines and steam turbine with different turbines, and constructing a larger auxiliary boiler and smaller cooling tower and emergency diesel fire pump engine (ASE 2015). The Petition to Amend (PTA) also requests that the BEP II name be changed to Sonoran Energy Project.

Due to the number of changes to the project site area over the duration of its development and operation, the following timeline is provided in **Cultural Resources Table 1** Below.

Cultural Resources Table 1
Timeline of Blythe Energy Project

Year	Changes to Project Site
1999	Blythe Energy Project (BEP) Application for Certification Filed
2001	Commission Decision BEP: Approves the Blythe Energy Project, a natural gas-fired combined cycle power plant and transmission via interconnection with Western's Blythe Substation BEP Amendment Filed
2002	Memorandum of Agreement (MOA) between Western and OHP concerning the Blythe Power Plant Site Expansion Riverside County, California CA-RIV-6725H excavation CA-RIV-6370H excavation Commission Decision BEP I Amendment: Approves the elimination of two evaporation ponds and a retention basin on the expansion site. BEP II AFC filed
2003	*Blythe Energy Projects American Indian Ethnographic Assessment Study* completed
2005	The MOA amended to include Caithness as a concurring party. Commission Decision BEP II: Approves the construction of a 520 MW combined-cycle facility at the same location as BEP, adding 76 acres of land for project use Energy Commission determines CA-RIV-6725H no longer eligible to the California Register of Historical Resources
2007	OHP determines that CA-RIV-6370H remains eligible to the National Register of Historic Places (NRHP)
2015	BEP II Amendment AFC filed

SUMMARY OF THE DECISION

The list below provides a short summary of the licensed BEP II 2005 Decision (CEC 2005b) with regards to the Cultural Resources technical area. Based on the evidence presented in the original proceeding, the California Energy Commission (Energy Commission) made the findings and conclusions listed below.

- The project owner will designate a cultural resource specialist who will monitor excavation and, in the event of an unanticipated discovery, provide for the handling and curation of any recovered cultural resources. Conditions of Certification **CUL-1** through **CUL-7**;

- A Tribal Monitor shall be obtained to monitor excavations in undisturbed sediments in areas where Native American artifacts are discovered. Condition of Certification: **CUL-6**;
- Given the cumulative impacts of the project to off-site cultural resources important to tribes, the project owner shall invite tribal leaders to bless the project area and conduct other appropriate ceremonies. Condition of Certification: **CUL-9**;
- The project owner shall provide copies to the Compliance Project Manager (CPM) of documents submitted to Western, demonstrating compliance with Section 106 of the National Historic Preservation Act (NHPA). If the project owner becomes a signatory to the MOA for the project, then correspondence regarding compliance with the stipulations of that agreement shall be provided to the CPM. Condition of Certification: **CUL-10**; and
- The project's cumulative cultural resources impacts would be less than significant with the implementation of Conditions of Certification **CUL-1** through **CUL-9.**

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The following LORS applicable to the project have changed since the 2005 Decision was published in August 2005. However, no changes to the LORS result in any substantive modifications to cultural resources mitigation measures contained in the 2005 Decision.

FEDERAL

No federal LORS applicable to the project owner have changed since the Commission Decision was published in December 2005.

However, it is not certain if the MOA (required under Section 106 of the NHPA) identified in **CUL-10** to resolve adverse effects to CA-RIV-6370H, remains in effect. This archaeological site consists of landform modifications (grading, trenching, and push piles) and artifacts associated with the historic military use of the Blythe Army Air Base and/or the Desert Training Area. BEP II is required to fence-off the refuse site and restrict all activities within this area (CEC 2005b). This agreement is partially enforced through Condition of Certification **CUL-8**. However, it is not certain if AltaGas was required to, or indeed accepted a contractual obligation to interests in the terms of the MOA as stipulated in **CUL-8**.

STATE

No state LORS applicable to the project owner have changed since the Commission Decision was published in December 2005.

However, since 2011, Executive Order B-10-11 directs state agencies under the direction of the Governor to develop and implement tribal consultation policies. In response to the Executive Order, and more recent amendments to CEQA that further detail lead agency responsibilities to consult with tribal governments, the Energy Commission staff have increased tribal consultation activities. As a result of state-tribal consultation Condition of Certification **CUL-9** may be revised.

LOCAL

Riverside County

The Riverside County General Plan (Riverside 2003) sets out parameters for recording, assessing, and protecting historic and prehistoric resources. Since 2003, it was updated in December 2014, and as of December 2015 is being considered for additional revision approval by the County Board of Supervisors (Riverside 2014). The 2014 General Plan revisions do not affect cultural resources except for the directive that as of July 1, 2015, all cultural resources reports prepared for proposed private development projects within the unincorporated County of Riverside shall be submitted directly to the office of the County Archaeologist for review.

Riverside County's Ordinance 578 (Riverside 2011) applies to the creation and protection of historic districts, and was amended in January 2011 to reflect changes to application processing. The original intent, purpose, objectives and means of establishing historic districts within the County has not been altered however, and there are no applicable changes affecting SEP.

City of Blythe

Since the 2005 Decision, the City of Blythe General Plan 2025, Chapter 6, Section 7, Policy 25, has been published (March 2007) and establishes city policy in regard to "Archaeologic, Historic and Paleontologic Resources" to "protect archaeologic, historic and paleontologic resources for their aesthetic, scientific, education, cultural value." Two implementation measures are set forth in support of Policy 25: 1) Records searches be conducted for all projects situated in areas of high archaeological sensitivity, and 2) Use of a consulting archaeologist for the creation and implementation of environmental mitigation measures for known and potentially present but undiscovered cultural resources.

Changes to the county and city general plans do not create any new measures for SEP compliance, and the original 2005 Decision on local ordinances can be relied upon.

CONSULTATION WITH NATIVE AMERICAN TRIBAL GOVERNMENTS

The Energy Commission Cultural Recourses staff contacted the Native American Heritage Commission (NAHC) on September 16, 2015 to conduct a search of the Sacred Lands File (SLF) and to determine the appropriate tribes that may be affiliated with the SEP. The NAHC response did not arrive as expeditiously as anticipated, and therefore staff sent letters on September 30, 2015 to the sixteen tribal governments with whom staff typically consults on projects in the Palo Verde Mesa area, informing them of project details and offering to consult with them regarding the SEP amendment. The

NAHC responded on October 7, 2015 that the search of the SLF was negative, and included five groups on the contact list, all of whom were included in the staff September 30, 2015 mailing. Staff followed up letters with phone calls and e-mails in early October 2015. The contacted tribes are listed in the **Cultural Resources Table 2** below.

Cultural Resources Table 2
Native American Communities Contacted for SEP

Tribe	Cultural Affiliation(s)
Augustine Band of Cahuilla Indians	Cahuilla
Agua Caliente Band of Cahuilla Indians	Cahuilla
Cabazon Band of Mission Indians	Cahuilla
Cahuilla Band of Mission Indians	Cahuilla
Chemehuevi Indian Tribe	Chemehuevi
Cocopa Indian Tribe	Cocopa
Colorado River Indian Tribes	Mohave, Chemehuevi, Navajo, Hopi
Fort Mojave Indian Tribe	Mojave
Morongo Band of Mission Indians	Serrano, Cahuilla, Cupeno
Quechan Indian Tribe, Fort Yuma Indian Reservation	Quechan
Ramona Band of Cahuilla	Cahuilla
San Manuel Band of Mission Indians	Serrano
Santa Rosa Band of Cahuilla Indians	Cahuilla
Soboba Band of Luiseno Indians	Luiseno, Cahuilla
Torres-Martinez Desert Cahuilla Indians	Cahuilla
Twenty-Nine Palms Band of Mission Indians	Chemehuevi

Staff has received six (6) reply correspondences from tribes.

- E-mail from the Chemehuevi Tribe, October 10, 2015;
- E-mail from the Cocopa Tribe, October 25, 2015;
- Phone call from the Cabazon Tribe, October 27, 2015;
- Letter from the Soboba Band of Luiseno Indians, October 29, 2015;

- Follow-up E-mail from the Soboba Band of Luiseno Indians, November 16, 2015; and
- E-mail from the San Manuel Band of Mission Indians, November 18, 2015.

COMMENTS IN CORRESPONDENCES FROM TRIBES AND STAFF RESPONSES

CHEMEHUEVI TRIBE

The director of cultural resources for the tribe had no further comments, but asked for notification in the event of a project discovery of cultural resources.

Staff Response: Duly noted.

COCOPA TRIBE

The director of cultural resources for the tribe had no comments and deferred to tribes more closely affiliated with the project area.

Staff Response: Duly noted.

CABAZON TRIBE

The director of cultural resources for the tribe had no comments and deferred to tribes more closely affiliated with the project area.

Staff Response: Duly noted.

SOBOBA BAND OF LUISENO INDIANS

The Director of Cultural Resources for the tribe notes that the SEP area is within the Soboba Band of Luiseno Indians' Tribal Traditional Use Areas, and is regarded as highly sensitive to the people of the Soboba Band of Luiseno Indians. The Soboba Tribe also requested that:

1. The Energy Commission initiate consultation;
2. The Energy Commission transfer information regarding the project to the tribe;
3. Native American monitors from the tribe be present during any ground-disturbing activities;
4. Procedures regarding the treatment of archaeological materials and human remains be followed as outlined in the attachment to their letter; and
5. Any documentation regarding the monitoring of the engineered fill be submitted to the tribe.

<u>Staff Response</u>: Staff acknowledged the receipt of the letter and initiated consultation. Staff is identifying pertinent project documents that can be provided to all tribes that the Energy Commission has initiated consultation with for SEP. CUL-6 provides opportunity for tribal monitoring.

<u>SAN MANUEL BAND OF MISSION INDIANS</u>

The assistant director of cultural resources for the tribe asked to be apprised of project development but also deferred to tribes more closely affiliated with the project area.

Staff Response: Duly noted.

ENVIRONMENTAL IMPACT ANALYSIS

In accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that some revision to the 2005 Decision may be necessary for Cultural Resources. The Committee may rely upon the environmental analysis and conclusions of the 2005 Decision with regards to cultural resources as follows:

- The changes in the Petition to Amend (PTA) would not create new significant environmental effects or substantial increases in the severity of previously identified significant effects;
- The PTA does not propose substantial changes which would require major revisions of the Cultural Resources analysis in the 2005 Decision; and
- The circumstances under which the amended SEP would be undertaken would not require major revisions of the Cultural Resources analysis in the 2005 Decision.

However the Committee may need to re-analyze existing mitigation measures as follows:

- The circumstances under which the amended SEP is conditioned may require some revisions to Conditions of Certification **CUL-9** and **CUL-10** in the 2005 Decision.

Staff's conclusion is supported by the following key factual information listed below.

- Changes to state LORS, as well as to the Riverside County Comprehensive General Plan (Riverside 2003, 2014) have occurred since the 2005 Decision on BEP II, yet no changes to the LORS result in any substantive modifications to cultural resources mitigation measures approved by the 2005 Decision;
- The PTA proposes re-routing the gen-tie line, replacing the previously approved combustion turbines and steam turbine with different turbines, and constructing a larger auxiliary boiler and smaller cooling tower and emergency diesel fire pump engine. These changes do not require revisions to the cultural resources analysis in the 2005 Decision;

- With implementation of existing Conditions of Certification **CUL-1** to **CUL-10**, the amended SEP would be consistent with the city of Blythe and the County of Riverside's revised cultural resources plans and ordinances;
- Existing Conditions of Certification **CUL-1** to **CUL-8** would remain applicable and feasible, and the project proponent, AltaGas Sonoran Energy Inc., has not requested any changes to the conditions;
- Existing Condition of Certification **CUL-9** may be subject to revision based upon ongoing consultations with affiliated tribal governments. There are discrepancies among: 1) the list of tribes contacted in 2005 when there was a past federal (Western) nexus to the project, 2) the list of tribes named in **CUL-9,** and 3) the list of tribes that staff routinely consults with on projects in the same area and over the last 5 years; and
- Existing Condition of Certification **CUL-10** may be subject to revision based upon ongoing consultation with Western and the OHP concerning: 1) the current status towards completing the stipulations of an NHPA, Section 106 resolution of adverse effect Memorandum of Agreement (MOA) mentioned in **CUL-8** and **CUL-10**, and 2) the continued applicability of the MOA for the SEP.

As part of the BEP project and its subsequent amendment, an intensive pedestrian survey of the property was completed. The 1999-2001 survey, augmented in 2003-2004, of the 76-acre BEP Amendment project area revealed four historic sites and two isolated prehistoric artifacts. The two isolated prehistoric artifacts found on the plant site consisted of a single flake and core of chert. Four archeological deposits recorded in the BEP and Amendment site areas were determined to not meet the criteria for eligibility for the California Register of Historical Resources (CRHR). These four deposits were destroyed during construction of the BEP.

Two archeological deposits were recorded within the BEP expansion areas (10-acre and 66-acre Earth fill area) and are within the proposed SEP plant site. The recording and subsurface testing of CA-RIV-6725H recovered the information values that the deposit contained. In 2005 (CEC2005b), it was determined that the deposit no longer meet the criteria for eligibility for the CRHR (CEC2005b).

Cultural resource CA-RIV-6370H was excavated in 2002 and determined eligible for the CRHR in 2005. Condition of Certification **CUL-8** prohibits the project owner or its agents from conducting any activities within the fenced portion of CA-RIV-6370H or removing any portion of the fence without prior approval from the Energy Commission Compliance Project Manager. Following the implementation of the 2005 MOA between Western and OHP, and as amended in 2007 to include Caithness as a concurring party, CA-RIV-6370H was determined by OHP to be eligible for the NRHP under Criterion D (OHP 2007). CA-RIV-6370H remains eligible for the CRHR (Forrest 2016). The OHP recommends re-opening consultation regarding this resource if the proposed project has potential to impact resource CA-RIV-6370H; Western does not assume the termination of the 2005 MOA (Bilsbarrow 2016).

The affected environment has not substantially changed since the 2005 Decision (02-AFC-01C), as amended, and potential impacts to cultural resources are the same as previously analyzed. A new literature search was completed by CH2M Hill consultants on November 6, 2014 (ASE 2015a). This review involved a records search of the files at the Eastern Information Center California Historical Resources Information System (CHRIS) at the University of California, Riverside. A one-eighth mile buffer zone around all proposed disturbance areas was included in this search. The CHRIS records search contained a review of all recorded archaeological sites as well as all known cultural resource survey and excavation reports. The NRHP, the CRHR, Archaeological Determinations of Eligibility (ADOE), California Historical Landmarks, and California Points of Historical Interest, were examined as well.

A survey was completed on November 14, 2014 by CH2M Hill consultants. This pedestrian survey was conducted in transects of 10 to 15 meters wide and covered all of the new interconnection that is located north of the SEP parcel, as well as a 200-foot buffer around the east, west, and north sides of new interconnection. Visibility was excellent at nearly 100 percent. No additional resources were identified as a result of this updated literature search and survey (ASE 2015b).

The proposed project amendment would have no new cultural resources impacts and would not likely result in a change or deletion of the mitigation measures **CUL-1** through **CUL-8** adopted by the 2005 Decision.

CUL-9 is addressed in the Cumulative Impacts section below.

CUL-10 may be subject to further revision. If Western and OHP determine that the MOA should be terminated, then **CUL-10** may be stricken in its entirety. However, if it is determined that the MOA remains in effect, then **CUL-10** may be revised to reflect the outcome of further consultations with Western and OHP. In addition, if it is determined that the MOA shall remain in effect, staff will need to verify if the second part of **CUL-8** (new owner recognition in purchase agreements or contracts of its acquired obligations as stipulated in the MOA) was implemented during the process of transfer of the property ownership from Caithness to AltaGas.

CUMULATIVE IMPACTS

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 impacts taking place over a period of time.

Two reasonably foreseeable development projects within approximately one mile, and an additional seven projects within 10 miles of the project site, were identified in staff's updated cumulative project list (see Cumulative Impacts **Executive Summary - Appendix A Table 1)**. The SEP would not impact any known historical resources. Mitigation measures are in place to avoid impacts to cultural resources that may be discovered during construction and to mitigate the impacts to any resources meeting eligibility criteria that cannot be avoided. Condition of Certification **CUL-9** was required to mitigate the BEP II's contribution to cultural resources impacted offsite. With implementation of mitigation measures **CUL-1** through **CUL-10**, project-specific impacts would be less than significant. Therefore, the project's contribution to cumulative cultural resources impacts would be less than cumulatively considerable.

However, staff continues to conduct consultations with the affiliated tribes regarding **CUL-9** and more specifically whether the **CUL-9** tribal list is the most appropriate list. Outcomes of on-going tribal consultation may result in future revisions to **CUL-9**.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the PTA would have no new cultural resources impacts, and mitigation measures for the original project would still be applicable and would not require any substantive changes. Therefore, staff also concludes that the findings of fact from the licensed BEP-II Commission Decision would still apply to the amended SEP:

- If a buried cultural resource meeting eligibility requirements is discovered during construction, then mitigation measures **CUL-1** through **CUL-7** would reduce the impacts to less than significant;
- 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 LORS;
- **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. However, it is indeterminate to staff if the MOA is still applicable to the project, and further if the MOA obligations were transferred from Caithness to AltaGas as specified in the condition;
- As a result of past Western tribal consultations, staff identified significant off-site cultural resources that would be cumulatively impacted by the BEP II. **CUL-9** is a measure that would reduce those impacts to less than significant. However discrepancies in various tribal contact lists are subject to ongoing consultations, and may result in future revisions to **CUL-9**; and
- **CUL-10** requires that the Energy Commission be informed of the compliance with federal historic preservation laws as further stipulated in an MOA. Although the federal agency is responsible for this compliance in consultation with the OHP, the condition allows the Energy Commission to ensure that the project is in conformance with federal regulations. However, it is not certain if the federal compliance would still apply to the project as proposed. Staff may provide future revisions to **CUL-10**.

PROPOSED CONDITIONS OF CERTIFICATION

Existing Conditions of Certification **CUL-1** through **CUL-10** would be sufficient to reduce impacts from the proposed amendment to a less than significant level and ensure the project remains in compliance with applicable LORS. Therefore, staff does not propose any modifications to the existing Conditions of Certification **CUL-1** through **CUL-8**. Conditions of Certification **CUL-9** and **CUL-10** remain as written in the 2005 Decision but may be subject to future revisions that reflect the outcomes of on-going consultation with tribes (**CUL-9**), and Western and OHP (**CUL-10**).

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:

a. 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

b. 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 Area Power Administration (Western) that the proposed CRS or alternate has the appropriate training and background to effectively implement the mitigation measures.

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, supersede 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.

<u>Verification:</u> 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 involved in ground disturbance 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, linear facilities 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 project owner 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 and to Western 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 project owner 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. The project owner, the CRS, the CPM and Western will meet to discuss the monitoring requirements prior to the approval of any 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 noncompliance 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 prior to ground disturbing activities 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: At least 30 days prior to ground disturbing activities, 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.

If the tribes indicate that they are not interested in the blessing ceremony, the project owner shall, prior to ground disturbance, provide to the CPM for review and Western copies of telephone logs and correspondence with the aforementioned tribes documenting that the tribes have declined to accept the offer for the blessing ceremony.

Within 15 days of CPM acceptance of the documentation demonstrating that the ceremony is not desired, the project owner shall provide a letter to all parties listed in this condition notifying them that the ceremony is no longer desired.

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.

REFERENCES

ASE 2015a - AltaGas Sonoran Energy Inc. Application for Confidential Designation fo Cultural Resources Records (TN 2015371). Docketed 7/16/2015.

ASE 2015b - AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

Bilsbarrow 2016 - *Personal Conversation between Diana Dyste and M. Bilsbarrow, Western Area Power Administration, 1/22/2016*.

CEC 2005a - California Energy Commission. Cultural Resources Section Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC 2005b - California Energy Commission. Cultural Resources Section Final Commission Decision (TN 64945). Docketed on 4/26/2015.

CEC 2012a - California Energy Commission. 2009 Petition to Amend – Staff Analysis (TN 60499). Docketed on 3/12/2012.

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City of Blythe 2011 - *Ordinance No. 578.5. An Ordinance of the County of Riverside Governing the Establishment of Historic Preservation Districts and Regulating Activities Therein.* Blythe, CA: City of Blythe Planning Department.

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Halmo 2003 - David B. Halmo. *Blythe Energy Projects American Indian Ethnographic Assessment Study: Final Report*. Prepared for Greystone Environmental Consultants. August 2003.

OHP 2007 - Office of Historic Preservation. Letter from OHP to Western Area Power Administration, *Re: Blythe Energy Power Plant Expansion Project*. July 20, 2007.

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SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
HAZARDOUS MATERIALS MANAGEMENT
Brett Fooks

SUMMARY OF CONCLUSIONS

Pending receipt and review of the requested supplemental Offsite Consequence Analysis (OCA) information before staff's Final Staff Assessment (FSA), staff expects that the proposed amendment will not present any increase in the potential for significant impacts to the public or the environment resulting from the use of hazardous materials at the project. Without the OCA, staff is unable to conclude that no supplementation to the 2005 Decision and 2012 Order is needed in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162).

Staff also expects the supplemental OCA information, with the existing conditions of certification resulting from the original decision and subsequent Petition to Amend (PTA) (with one change), hazardous materials storage and use at the Sonoran Energy Project (SEP) would comply with all applicable laws, ordinances, regulations, and standards (LORS) and would not result in any unmitigated significant potential impacts to the public or environment.

INTRODUCTION

The purpose of this analysis is to determine whether this Petition to Amend (PTA) would require new mitigation or modified **Hazard Materials Management** conditions of certification. The project site for SEP is the same as the previously licensed, and amended, Blythe Energy Project II (BEPII). The proposed modifications would fall within the same footprint as the licensed BEPII project. SEP would be located within the City of Blythe, in eastern Riverside County, California on a previously disturbed site adjacent to the existing Blyth Energy Project (BEP).

The affected environment has not substantially changed since the 2005 Final Decision. The project would be constructed on 34 acres with the existing 76 acre licensed site. The 76 acre SEP site is bounded to the north by Riverside Avenue, to the east by the existing BEP facility, and to the south by Hobson Way. There are currently no structures to the west of the proposed plant location. The project site is enclosed by a permanent exclusionary fence and is located on fill material. The electrical interconnection is via a 161-kilovolt (kv) line connecting to the existing Buck Boulevard substation to tie into an existing transmission line. The interconnection will be built on the previously surveyed SEP site.

SUMMARY OF THE DECISION

The Commission's 2005 Final Decision and subsequent amendment adopted in 2012 found that the storage, use, and transportation of hazardous materials would not result in any significant direct, indirect, or cumulative adverse impacts to the public or environment. With adoption of the conditions of certification proposed at the time, the Commission found that the project would comply will all applicable LORS and would not result in any unmitigated significant impacts.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

There have not been any applicable updated LORS since the Commission Decision was adopted and amended.

ENVIRONMENTAL IMPACT ANALYSIS

Staff has reviewed the PTA for potential environmental effects and consistency with applicable LORS. Staff has determined that the PTA does not increase or decrease the use, storage, or transportation of hazardous materials except for an increase in the amount of 29 percent concentration aqueous ammonia to be stored on-site. Due to the increase in the amount of aqueous ammonia, staff requested an updated Offsite Consequence Analysis (OCA) from the petitioner (AES2015g). Staff reviewed the submitted OCA and requested that some supplemental information be added to the OCA analysis (CEC2016a). Staff is waiting for the supplemental information to be submitted.

Based upon experience with prior projects having similar terrain and quantities of ammonia, staff fully expects that the use, storage, and handling of aqueous ammonia at the proposed facility will not present a significant risk of impact upon the public or the environment. However, until the supplemental risk assessment information has been submitted and reviewed, staff cannot firmly make this conclusion.

After reviewing the PTA, staff has revised Condition of Certification **HAZ-6** to remove the reference to anhydrous ammonia. The anhydrous ammonia was originally proposed to be used in the air inlet chillers (CBE2002a), but which were removed from the project in the previous PTA (CBE2009a). Therefore, anhydrous ammonia is no longer proposed for use at the project, and **HAZ-6** has been updated accordingly.

CONCLUSIONS AND RECOMMENDATIONS

Staff expects that, pending receipt and review of the requested supplemental information, the proposed amendment will not present any increase in the potential for significant impacts to the public or the environment resulting from the use of hazardous materials at the project. The existing conditions of certification resulting from the original decision and subsequent PTA (with the one change to **HAZ-6** discussed above) would provide adequate mitigation of potential risks.

PROPOSED CONDITIONS OF CERTIFICATION

Staff concludes that the existing conditions of certification, as modified, are sufficient to ensure that there would be no unmitigated significant impacts. Additions are shown in **bold underlined** text and deletions are shown in ~~strikethrough~~.

HAZ-1 The project owner shall not use any hazardous material not listed below, or in quantities greater than those identified by chemical name 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 those 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 to support plant commissioning and operations, 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 that 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 Hobson **W**~~w~~ay 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 DELETED; Order 12-0425-3a

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.

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 DELETED; Order 12-0425-3a

HAZ-11 DELETED; Order 12-0425-3a

HAZ-12 The project owner shall not conduct or allow any fuel gas pipe cleaning activities on the site involving fuel gas pipe of four-inches or greater external diameter, either before placing the pipe into service or at any time during the lifetime of the facility, that involve “flammable gas blows” where natural (or flammable) gas is used to blow out debris from piping and then vented to atmosphere. Instead, an inherently safer method involving a non-flammable gas (e.g. air, nitrogen, steam) or mechanical pigging shall be used. The project owner shall prepare a Fuel Gas Pipe Cleaning Work Plan which shall be consistent with NFPA 56 and which shall indicate the method of cleaning to be used, what gas will be used, the source of pressurization, and whether a mechanical PIG will be used, and submit this Plan to the CBO for information, to the Riverside County Fire Department for review and comment, and to the CPM for review and approval. Exceptions to any of these provisions will be made only if no other satisfactory method is available, and then only with the approval of the CPM after review and comment from the CBO and the Riverside County Fire Department.

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

ASE2015g. AltaGas Sonoran Energy Inc. Data Responses Set 1 (TN 206606). Docketed on 11/12/2015.

CBE2002a. Caithness Blythe Energy, Inc. Application for Certification (AFC), Vol. 1 & Vol. 2. (TN 24604). Docketed on 02/19/2002.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

CBE2009a. Caithness Blythe Energy, Inc. Petition to Amend (TN 53798). Docketed on 10/26/2009.

CEC2012a. California Energy Commission. 2009 Petition to Amend – Staff Analysis (TN 60499). Docketed on 3/12/2012.

CEC2012b. California Energy Commission. Commission Order Approving 2009 Petition to Amend (TN 64945). Docketed on 4/26/2012.

CEC2016a. California Energy Commission. Record of Conversation: Revised Offsite Consequence Analysis (TN 207284). Docketed on 1/12/2016.

SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
LAND USE
Andrea Koch

SUMMARY OF CONCLUSIONS

Staff concludes that the proposed amendment to the Blythe Energy Project Phase II (BEP II), named the Sonoran Energy Project (SEP), would require additional analysis and supplementation of the BEP II 2005 Commission Decision (2005 Decision) in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., titl. 14, § 15162) for the following reasons:

- Since the 2005 Decision, there have been changes in the laws, ordinances, regulations, and standards (LORS) applicable to the project. The city of Blythe has updated its General Plan, changing the project site from a Heavy Industrial (I-H) land use designation in the 1989 General Plan to a General Industrial (I-G) land use designation in the 2025 General Plan (CB2007a, CEC2005a). Also, the 1992 Blythe Airport Comprehensive Land Use Plan analyzed in the 2005 Decision was replaced by the updated Blythe chapter of the Riverside County Airport Land Use Compatibility Plan (ALUCP) adopted in October 2004 (CB2007, CEC2005a). Staff found no additional project impacts resulting from changes in these LORS.
- The 161 kilovolt (kV) gen-tie line is proposed on land not previously analyzed in the 2005 Commission Decision. This required staff to review Riverside County General Plan and zoning designations for conformance and evaluate any potential impacts to agricultural land. Staff found no additional impacts resulting from the gen-tie location.
- The project could result in more severe land use impacts from thermal plumes, which could affect aircraft safety and result in the project's incompatibility with the nearby Blythe Airport and the Riverside County ALUCP. The results of the project owner's thermal plume analysis predict higher velocity plumes for the SEP than the plumes analyzed under the 2005 Decision. Traffic and Transportation staff are also assessing whether aspects of Condition of Certification **TRANS-9**, included in the 2005 Decision to mitigate hazards from thermal plumes, are feasible. See the **Traffic and Transportation** section of this Preliminary Staff Assessment (PSA) for more information.
- The project could result in new land use impacts from evaporation ponds if they attract birds, which could impact aviation safety and result in the project being incompatible with the Blythe Airport and Riverside County ALUCP. See the **Traffic and Transportation** section of this PSA for more information regarding potential aviation hazards from birds. Staff understands the project owner is currently evaluating additional options for wastewater discharge. Staff continues to recommend the zero liquid discharge (ZLD) process approved in the 2005

Decision, which would avoid these impacts. See the **Biological Resources** section of this PSA for more information on this recommendation.

A final determination of the project's land use compatibility with the Blythe Airport and the Riverside County ALUCP will be included in the Final Staff Assessment (FSA) for Land Use. With the possible exception of this pending issue, the amended SEP would comply with all applicable LORS and, with implementation of Conditions of Certification **LAND-1** through **LAND-6** from the 2005 Decision, would not cause any significant land use impacts.

Staff should note that Soil and Water Resources staff is recommending in this PSA that the project use dry-cooling instead of wet-cooling. Soil and Water Resources staff estimates that dry-cooling would use approximately 10 percent the amount of water as wet-cooling. (See the **Soil and Water Resources** section of this PSA for more information.) In the event that dry-cooling becomes part of the SEP project description, reduced water use would mean that the project owner could retire a smaller amount of agricultural land as part of the Water Conservation Offset Program (WCOP). As a result, to fulfill the requirements of **LAND-3**, which requires that the project owner mitigate for any agricultural land permanently fallowed as part of the WCOP, the project owner would be able to pay lower mitigation fees or secure an easement for a smaller amount of agricultural land. If the SEP project owner participates in the WCOP by rotational fallowing, rather than permanent retirement of irrigated agricultural land, impacts to agricultural lands would be less than significant and would not need mitigation by **LAND-3**.

INTRODUCTION

The project owner proposes an amendment to the license for the BEP II that includes a name change to the SEPand the following changes: a new route for the electrical transmission (gen-tie) line; replacement of the two licensed combustion turbines with one combustion turbine of a different type; replacement of the licensed steam turbine generator (STG) with another type of STG; an increase in the size of the auxiliary boiler; and a decrease in the size of the cooling tower. Staff analyzed these changes for any potential impacts to Land Use.

SUMMARY OF THE DECISION

The following is a summary of the Energy Commission's findings for Land Use impacts in the 2005 Decision for BEP II:

- The project, located in a largely non-urbanized area, would not physically divide an established community;
- The project would not adversely affect agricultural practices and crops and would not restrict normal operations of citrus orchards in the area, with the implementation of Conditions of Certification in the **Air Quality** section that require control of fugitive dust;

- If the project owner's participation in the WCOP were to involve permanent retirement of irrigated agricultural land in the Palo Verde Irrigation District (PVID), any impacts to agricultural land would be mitigated by Condition of Certification **LAND-3**, which requires the project owner to acquire an agricultural easement or pay a mitigation fee to the Riverside County agricultural land trust or American Farmland Trust to mitigate any loss of agricultural land at a one-to-one ratio. On a general basis, there would not be a significant impact to agricultural lands that would need to be mitigated if the rotational land fallowing option were chosen;
- With implementation of Condition of Certification **TRANS-9**, the project would not impact flight safety near the Blythe Airport. Condition of Certification **TRANS-9** requires that: pilots are notified to avoid overflight of the plumes; the Visual Flight Rules (VFR) traffic pattern to Runway 26 is changed from left-hand turns to right-hand turns; and that a runway other than Runway 26 is designated as the primary calm wind runway;
- The project's physical structures (not including the plumes) do not pose an obstruction hazard to aircraft, as determined by the FAA;
- The project is consistent with the city of Blythe's General Plan land use designation of Heavy Industrial (I-H);
- The project is consistent with the city of Blythe's zoning designation of General Industrial (I-G), with the exception of the maximum height restriction of 34 feet. However, the city's Planning Department approved a height variance request on March 8, 2004 for three 125-foot-tall transmission towers, two 130-foot-tall exhaust stacks, and one 99-foot-tall high brine concentrator; and
- The project would not cause significant growth-inducing impacts.

The Energy Commission found that with implementation of Conditions of Certification **LAND-1** through **LAND-6**, the project conformed to applicable laws related to land use, and all potential land use impacts would be mitigated to less than significant.

The subsequent Commission Decision approving the 2009 Petition to Amend (PTA) did not include a new Land Use analysis, as staff determined it was not needed (CEC2012a, CEC2012b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

Staff has performed an updated LORS analysis because of project modifications and changes to several LORS applicable to the project since the 2005 Commission Decision.

Since the 2005 Decision, the city of Blythe has updated its General Plan from the version adopted in 1989 to the 2025 General Plan adopted in 2007. In the General Plan adopted in 1989, the project site was classified as Heavy Industrial (I-H). In the 2025

General Plan, it is classified as General Industrial (I-G) (CB2007a). Also, the staff analysis upon which the 2005 Decision was based referred to the 1984 Riverside County Comprehensive General Plan (CEC2005a). The current version of the Riverside County General Plan was adopted on October 7, 2003 (RC2003).

Another LORS change since the December 2005 Decision is the updated Blythe chapter of the Riverside County ALUCP, which was adopted in October 2004 (CB2007). The 2005 Decision considered the policies in an earlier version of the plan called the Blythe Airport Comprehensive Land Use Plan, dated August 1992 (CEC2005a).

The height of the SEP's proposed exhaust stack is 140 feet, taller than the previous project's proposed exhaust stacks of 130 feet, which triggered a LORS review for height compliance. Because Section 17.10.040 of the City of Blythe Zoning Ordinance requires that buildings shall not exceed a maximum of 34 feet in height (CB2015), the SEP would require a variance from the city of Blythe for LORS conformance. The city of Blythe approved a variance for the original project on March 8, 2004. Staff considers the city's variance findings for the original project as applicable to the SEP. However, in the event dry-cooling is proposed, an air cooled condenser (ACC) would be necessary, and the variance findings would not necessarily apply to the ACC. See additional discussion under the section "Compliance with Zoning Regulations", below.

Finally, the SEP's gen-tie line is proposed on land not previously analyzed under the 2005 Commission Decision, which required staff to review Riverside County General Plan and zoning designations for conformance.

The LORS applicable to this project which require new discussion are described in the table below, along with a brief summary of the project's consistency with these LORS. For a detailed discussion of the project's consistency with these LORS, see the "Environmental Impact Analysis" section below.

Land Use – Table 1
SEP Compliance with Adopted Land Use LORS

Applicable LORS	Description
Local	
City of Blythe 2025 General Plan (CB2007)	Provides a land use designation of General Industrial (I-G) with a maximum floor-area-ratio (FAR) of 0.5. <u>Consistent</u>: The project is consistent with the General Plan land use designation and the maximum FAR of 0.5.
City of Blythe Zoning Ordinance (CB2015)	Provides a zoning designation of General Industrial (I-G) and a maximum height for buildings of 34 feet unless a variance is obtained. The applicable parts of the Zoning Ordinance have not changed since the 2005 Commission Decision. <u>Consistent</u>: While the project use is allowed by-right in the I-G zone, the SEP's exhaust stack exceeds the 34-foot height limit. It is proposed to be 140 feet-tall, taller than the two 130-foot-tall exhaust stacks analyzed under the 2005 Commission Decision. The city of

Applicable LORS	Description
	Blythe approved a height variance request for the exhaust stacks analyzed in the 2005 Commission Decision (CEC2005b), but to staff's knowledge, the city has not processed a height variance for the taller SEP exhaust stack. Staff considers the city's variance findings for the original project as applicable to the SEP, which is just 10 feet taller at its highest point than the BEP II, and which only has one tall exhaust stack instead of two. In the event that dry-cooling is proposed, as recommended in the **Soil and Water Resources** section of this PSA, an ACC of approximately 130 feet in height would be needed, and this would also require a variance for LORS conformance. The city's March 2004 variance findings would not necessarily apply to the ACC. Staff is coordinating with the city of Blythe to determine whether an additional variance would be needed in this situation. More information will be included in the FSA.
Riverside County General Plan (RC2003)	Provides a General Plan land use designation of Agriculture for the site of the three transmission poles that are part of the new 161-kV gen-tie line. <u>Consistent</u>: The project does not conflict with any related policies in the General Plan.
Riverside County Zoning Ordinance (CR2015)	Provides a zoning designation of W-2-10, "Controlled Development Area", for the site of the three transmission poles that are part of the new 161-kV gen-tie line. <u>Consistent</u>: Transmission poles are allowed by right in this zone.
2004 Blythe Airport Land Use Compatibility Plan (RCALUC2004)	Table 2A of the ALUCP prohibits hazards to flight in airport compatibility zones "C" and "D" in which the project is located. <u>Consistency Undetermined</u>: The SEP's plumes could potentially pose a more severe hazard to aircraft than the BEP II's plumes. Traffic and Transportation staff have discovered that several of the measures included in **TRANS-9** to mitigate flight hazards from thermal plumes might not be feasible. If parts of **TRANS-9** cannot be implemented due to infeasibility, the SEP's plumes could pose an unmitigable hazard to flight, making the SEP incompatible with the Blythe Airport and Riverside County ALUCP. See the **Traffic and Transportation** section of this PSA for more information. The project could also result in new impacts if birds are attracted to the evaporation ponds, which could impact aviation safety and result in the project being incompatible with the Blythe Airport and Riverside County ALUCP. See the **Traffic and Transportation** section of this PSA for more information regarding potential aviation hazards from birds. Staff understands the project owner is currently evaluating additional options for wastewater discharge. Staff continues to recommend the ZLD process approved in the 2005 Commission Decision, which would avoid these impacts. See the **Biological Resources** section of this PSA for more information on this recommendation. Staff will make a final determination on land use compatibility in the FSA.

ENVIRONMENTAL IMPACT ANALYSIS

Staff analyzed the LORS changes and proposed project changes to evaluate whether the SEP would create any new significant impacts, substantially increase the severity of previously identified significant impacts, or involve substantial changes or a change in circumstances which would require major revisions of the Land Use analysis in the 2005 Decision. The discussion below is separated by topic area.

COMPLIANCE WITH GENERAL PLANS

Since the 2005 Decision, the city of Blythe has updated its General Plan from the version published in 1989 to the 2025 General Plan. In the 1989 General Plan, the project site was classified as Heavy Industrial (I-H). In the 2025 General Plan, it is classified as General Industrial (I-G) (CB2007, CB2007a). These General Plan land use designations are similar, as the new I-G designation allows for a broad range of industrial uses, but the new I-G General Plan land use designation focuses less on heavy industrial uses, many of which would require a conditional use permit under the corresponding I-G zoning designation (CB2015). Section 3.6 of the City of Blythe 2025 General Plan states that the project site’s I-G land use designation is “intended to provide and protect industrial lands for the full range of manufacturing, agricultural and industrial processing, general service, and distribution uses” (CB2007). The proposed SEP is consistent with these allowed uses.

Section 3.6 of the City of Blythe 2025 General Plan also provides a maximum floor-area-ratio (FAR) of 0.5 for the I-G land use designation, with the caveat that increases in the FAR up to 0.8 may be permitted for uses with low employment intensities (CB2007). The SEP would have low employment intensities, with only nine employees during operation, so it would likely qualify for this allowance. However, the FAR for the project complies with the more restrictive general maximum FAR of 0.5. The project would be constructed on up to 34 acres of the approximately 76-acre licensed site, which is comprised of two parcels (Assessor Parcel Numbers [APN] 824-101-012 and 824-101-013). Even if the floor area of the project covered the entire 34 acres of the construction area, which it does not, the FAR of the project would be approximately 0.45 (calculated by dividing 34 acres by 76 acres), which complies with the general maximum FAR of 0.5. In reality, because the floor area of the project would only cover a portion of the 34-acre construction area, the FAR would be less than 0.45 and would be even further from the general maximum FAR of 0.5.

The SEP also involves proposal of a new 161-kV gen-tie line that runs from the north side of the SEP generator step-up unit transformer to the existing Buck Boulevard substation on the existing Blythe Energy Project (BEP) site. A portion of the gen-tie line would run eastward along the north side of W. Chanslor Way on Riverside County land not analyzed as part of the project under the 2005 Decision (ASE2015g). The SEP proposes three new transmission poles (Figure 2-2b in ASE 2015a) on property with a Riverside County General Plan land use designation of Agriculture. The transmission poles do not conflict with any applicable General Plan policies.

COMPLIANCE WITH ZONING REGULATIONS

The SEP site's zoning designation has not changed since the 2005 Decision. It has a city of Blythe zoning designation of General Industrial (I-G), which corresponds with its General Plan land use designation of I-G. According to Section 17.08.010 of the City of Blythe Zoning Ordinance, the SEP is compatible with the uses allowed in this zone. The I-G zone allows utility operations facilities, defined in Section 17.08.710 as including electrical generating plants, by right, and the use would not require the city to process a conditional use permit if the city had jurisdiction over the project (CB2015).

However, Section 17.10.040 of the city of Blythe Zoning Ordinance states that buildings shall not exceed a maximum of 34 feet in height (CB2015), and the SEP's exhaust stack is proposed to be 140 feet-tall, taller than the two 130-foot-high exhaust stacks analyzed under the 2005 Commission Decision. The SEP would therefore require a variance under Section 17.10.040 of the city of Blythe's zoning ordinance for LORS conformance. The city of Blythe approved a variance for the original project on March 8, 2004 (CEC2005b). Specifically, a variance was approved for three 125-foot-tall transmission towers, two 130-foot-tall exhaust stacks, and one 99-foot-tall high brine concentrator. Staff considers the city's variance findings for the original project as applicable to the SEP, which is just 10 feet taller at its highest point than the BEP II, and which only has one tall exhaust stack instead of two.

In the event that dry-cooling is proposed, as recommended in the **Soil and Water Resources** section of this PSA, an ACC of approximately 130 feet in height, 347 feet in length, and 181 feet in width would be needed. (See the **Visual Resources** section of this PSA for more information on the estimated size of the ACC.) The ACC would also require a variance for LORS conformance. The city's March 2004 variance findings would not necessarily apply to the ACC because the ACC would increase the project's bulk through its height, width, and depth. Staff is coordinating with the city of Blythe to determine whether an additional variance would be needed in this situation. If a variance would be needed for the ACC, the city of Blythe would need to make the following findings to approve it, as stated in Section 17.70.010 of the Zoning Ordinance (CB2015):

A) Because of special circumstances applicable to a property, including size, shape, topography, location or surroundings, strict application of a regulation contained in this title deprives such property of privileges enjoyed by other property in the vicinity and under identical zoning classification;

B) The conditions under which the variance is to be granted will assure that the authorized modification of regulations shall not constitute a grant of special privileges inconsistent with the limitations upon other properties in the vicinity and zone in which such property is situated; and

C) The variance does not authorize a use or activity which is not otherwise expressly authorized by the zone regulation governing the property.

Staff will include more information on this issue in the FSA.

As discussed earlier in this section, the SEP involves proposal of a new 161-kV gen-tie line that includes three transmission poles located on land in Riverside County not analyzed as part of the project under the 2005 Decision (ASE2015g). The property has a zoning designation of W-2-10, which is a “Controlled Development Area”. According to Section 15.1 of the County of Riverside’s Zoning Ordinance, structures and the pertinent facilities necessary and incidental to the development and transmission of electric power and gas, including transmission lines, are allowed by right in this zone (CR2015). Therefore, the location of the gen-tie line is consistent with Riverside County zoning.

COMPLIANCE WITH 2004 BLYTHE AIRPORT LAND USE COMPATIBILITY PLAN

As discussed earlier in this section, the 2005 Decision was based on a staff analysis of policies in the Blythe Airport Comprehensive Land Use Plan, dated August 1992 (CEC2005a). The Riverside County ALUCadopted an update in October 2004 as part of the new ALUCP. The City of Blythe’s 2025 General Plan adopts the updated ALUCP by reference (CB2007).

Like the BEP II project licensed in 2005, the SEP would be located in ALUCP compatibility zones “C” and “D”. Most of SEP’s new development occurs within compatibility zone “D”. Only the gen-tie infrastructure and access road are located within compatibility zone “C”. Policies 1.5.2 and 1.5.3 in the ALUCP state that the ALUC requests advisory review of “Major Land Use Actions”, which include structures more than 70 feet in height within ALUCP compatibility zone “C” and more than 150 feet in height within ALUCP compatibility zone “D” (RCALUC2004). The transmission infrastructure located in zone “C” proposed as part of the new 161-kV gen-tie line would exceed 70 feet in height and would therefore constitute a “Major Land Use Action” for which the ALUC requests advisory review. Although the ALUCP acknowledges that ALUC review is not required, Traffic and Transportation staff are corresponding with the ALUC regarding the potential for the project’s thermal plumes to more severely impact aviation safety as compared to the BEP II’s thermal plumes, as discussed further below. Through this process, the ALUCP will have advisory review of the height of the transmission poles.

The heat recovery steam generator (HRSG) stack is the tallest structure on the site at 140 feet and is located in zone “D”. Although the SEP’s HRSG stack is taller than the two 130-foot stacks approved by the 2005 Commission Decision, the new stack does not exceed ALUC’s threshold for review of 150 feet in zone “D” and therefore would not meet this criterion for a “Major Land Use Action” for which the ALUC requests review. It should be noted that the Federal Aviation Administration (FAA) has issued a Determination of No Hazard for the proposed 140-foot-tall HRSG stack (ASE2015a).

Table 2A of the ALUCP provides basic compatibility criteria for ALUCP land use compatibility zones. According to the table, prohibited uses in compatibility zones “C” and “D” include hazards to flight, which may include physical (such as tall objects), visual, and electronic forms of interference with the safety of aircraft operations. Land use development that may increase the attraction of birds is also prohibited (RCALUC2004).

Evaporation ponds can attract birds to power plants. The 2005 Decision states on page 58 that the BEP II would use a ZLD system, thus avoiding the regular use of evaporation ponds. Consistent with this statement, Condition of Certification **BIO-12** in the Decision states that the project owner shall discharge to the evaporation pond only in the cases of cooling system initial commissioning, maintenance, planned or forced outages, or emergency. It also requires that any discharge be pumped from the evaporation pond at the earliest opportunity, when supported by plant operations, and includes measures for discouraging birds from use of the pond during the brief times it would contain discharge.

In the PTA, the project owner does not propose changes to **BIO-12**. However, in conflict with **BIO-12**, the project owner proposes use of evaporation ponds instead of a ZLD system. Use of evaporation ponds could result in new land use impacts if birds were attracted to the ponds, which could impact aviation safety and result in the project being incompatible with the Blythe Airport and Riverside County ALUCP. See the **Traffic and Transportation** section of this PSA for more information regarding potential aviation hazards from birds. Staff understands the project owner is continuing to evaluate options for wastewater discharge, including options other than new evaporation ponds. Biology staff continues to recommend the use of a ZLD system. See the **Biological Resources** section of this PSA for more information on this recommendation. The FSA will contain a final analysis of evaporation pond use, bird attraction, and any resulting impacts to aviation and project land use compatibility with the Blythe Airport and Riverside County ALUCP.

The ALUCP does not include thermal plumes on its list of hazards to aircraft, although thermal plumes can be hazardous to flight. The 2005 Decision found that with implementation of **TRANS-9**, which would mitigate hazards from the BEP II's thermal plumes, the project would not pose hazards to flight (CEC2005b). During analysis of the SEP, Traffic and Transportation staff discovered that several of the measures included in **TRANS-9** to mitigate flight hazards from thermal plumes might not be feasible, including changing the Visual Flight Rules (VFR) traffic pattern to Runway 26 from left-hand turns to right-hand turns, and designating a runway other than Runway 26 as the primary calm wind runway (CEC2015c). If parts of **TRANS-9** cannot be implemented due to infeasibility, the SEP's plumes could pose an unmitigable hazard to flight, making the SEP incompatible with the Blythe Airport and Riverside County ALUCP.

Also, the SEP could potentially create higher velocity plumes than the BEP II, which would increase the SEP's potential impacts to aircraft. Traffic and Transportation staff are awaiting the results of an independent thermal plume analysis to be performed by Air Quality staff. This analysis will need to include thermal plumes generated by the staff-proposed ACC unit. Plume analysis results will be available in the FSA. (See the **Traffic and Transportation** section of this PSA for more information.) Staff will make a final determination on land use compatibility of the project with the Blythe Airport and the Riverside County ALUCP in the FSA.

AGRICULTURAL LAND IMPACTS

As discussed earlier in this section, the staff analysis upon which the 2005 Commission Decision was based referred to the 1984 Riverside County Comprehensive General Plan (CEC2005a). The current version of the Riverside County General Plan was adopted on October 7, 2003 (RC2003). Both versions of the Riverside County General Plan emphasize protection of agricultural lands. The City of Blythe's 2025 General Plan also promotes protection of agricultural lands. It includes the following policy on page 6-4: "Promote continued agricultural use of important farmland outside the urban area" (CP2007).

As discussed earlier in this section, the SEP involves proposal of a new 161-kV gen-tie line that includes three new transmission poles located on land in Riverside County not analyzed as part of the project under the 2005 Decision (ASE2015g). Along this part of the line on land not previously analyzed, there would be three new transmission poles (Figure 2-2b in ASE 2015a). The land has a General Plan land use designation of Agriculture and is classified as Farmland of Local Importance by the California Department of Conservation's Farmland Mapping and Monitoring Program. The parent company of the project owner owns the property on which the new transmission poles would be located. Because the poles are not located on Prime Farmland, Farmland of Statewide Importance, or Unique Farmland, impacts from the poles converting agricultural land to non-agricultural uses would be less than significant.

WATER CONSERVATION OFFSET PROGRAM PARTICIPATION

The project analyzed under the 2005 Commission Decision proposed use of wet-cooling, an intensive water use. To mitigate for BEP II's water use, the project owner proposed participation in the WCOP within the PVID. Participation in the WCOP could involve permanent retirement or temporary fallowing of agricultural lands to conserve water and mitigate the water use impacts of wet-cooling the project. However, the project owner's participation in the WCOP could impact agricultural lands by converting them to non-agricultural uses.

To mitigate for any permanent loss of agricultural land within the PVID's service area, Conditions of Certification **LAND-3** and **LAND-6** were adopted in the 2005 Commission Decision. Condition of Certification **LAND-3** states that if the project owner participates in the WCOP by permanently retiring land designated as Prime Farmland or Farmland of Statewide Importance, the project owner must mitigate the lost agricultural land at a one-to-one acre ratio. **LAND-6** states that the project owner shall not participate in the WCOP by retiring lands in the Palo Verde Valley (Priority I Lands) designated as Prime Farmland or Farmland of Statewide Importance, lands included in a Williamson Act Preserve, or lands currently involved in active orchard crop production.

Soil and Water Resources staff is recommending in this PSA that the project use dry-cooling instead of wet-cooling. **Soil and Water Resources** staff estimates that dry-cooling would use approximately 10 percent the amount of water as wet-cooling. (See the **Soil and Water Resources** section of this PSA for more information.) In the event the project uses dry-cooling, reduced water use would mean that the project owner could retire a smaller amount of agricultural land as part of the WCOP. As a result, to fulfill the requirements of **LAND-3**, the project owner would be able to pay lower mitigation fees or secure an easement for a smaller amount of agricultural land.

If the SEP project owner participates in the WCOP by rotational fallowing, rather than permanent retirement of irrigated agricultural land, impacts to agricultural lands would be less than significant and would not need mitigation by **LAND-3**.

OTHER POTENTIAL LAND USE COMPATIBILITY ISSUES

The siting of the proposed project at the existing location would not create new unmitigated significant adverse impacts in the following areas: **Air Quality**, **Hazardous Materials Management**, **Noise and Vibration**, **Public Health**, **Transmission Line Safety and Nuisance**, and **Visual Resources**. (Please refer to these sections of the PSA for detailed analyses of the air quality, dust, hazardous materials, noise, public health hazard, and nuisance impacts.) Therefore, impacts in these areas would not result in any physical land use compatibilities between the project and the existing surrounding land uses.

However, as discussed earlier in this section under the caption “Compliance with 2004 Blythe Airport Land Use Compatibility Plan”, aspects of Condition of Certification **TRANS-9**, which was included in the 2005 Decision to mitigate plume hazards, may be infeasible to implement. (See the **Traffic and Transportation** section of this PSA for more information.) Depending on the outcome, Traffic and Transportation staff could potentially conclude that the SEP would cause greater impacts to aviation safety than the project licensed under the 2005 Commission Decision. If these impacts could not be mitigated, they would create a land use incompatibility between the SEP and the Blythe Airport. Staff will make a final determination of land use compatibility in the FSA once more information is known.

CUMULATIVE ANALYSIS

Since the 2005 Decision, other projects in the area have been proposed, which makes a new cumulative impacts analysis necessary.

As discussed earlier in this section, the SEP would not directly convert Prime Farmland or Farmland of Statewide Importance, as classified by the California Department of Conservation’s Farmland Mapping and Monitoring Program, to non-agricultural uses. However, one potential indirect land use impact from SEP is removal of land from agricultural production if the project owner’s participation in the WCOP involves permanent retirement of irrigated Prime Farmland or Farmland of Statewide Importance in the PVID. Staff examined other projects in the area that could potentially combine with the SEP to cause a cumulative impact to agricultural lands. Staff narrowed the focus to projects both located in the PVID and located on Prime Farmland or Farmland of Statewide Importance as classified by the California Department of Conservation's Farmland Mapping and Monitoring Program. The only project that meets this criterion is the Blythe Mesa Solar Power Project. Details on this project are shown in the table below.

Land Use Table 1 – Cumulative Projects

Project	Description	Location	Type of Farmland	Distance to SEP (miles)	Status
Blythe Mesa Solar Power Project	485 MW solar photovoltaic facility and 8.4-mile generation interconnection line on 3,660 acres	One mile north and south of Interstate-10 (I-10) and three miles west of the city of Blythe	Prime	0.84	Approved

Although this project could combine with SEP to cause cumulative impacts to agricultural lands, Conditions of Certification **LAND-3** and **LAND-6** would mitigate the SEP's contribution to these cumulative impacts. **LAND-3** requires the project owner to acquire an agricultural easement or pay a mitigation fee to the Riverside County agricultural land trust or American Farmland Trust to mitigate any permanent loss of Prime Farmland or Farmland of Statewide Importance at a one-to-one ratio. **LAND-6** prevents the most important farmland from being fallowed as part of the WCOP. With implementation of these conditions, cumulative impacts to agricultural lands would be less than significant.

If the SEP project owner participates in the WCOP by rotational fallowing, rather than permanent retirement of irrigated agricultural land, cumulative impacts to agricultural lands would be less than significant and would not need mitigation by **LAND-3**.

Another possible cumulative impact resulting from the SEP would be to land use compatibility. The project could combine with the nearby BEP to cause significant cumulative impacts to aviation safety, and as a result, make the project incompatible with the Blythe Airport and Riverside County ALUCP. To analyze these impacts, staff would need to rely on Traffic and Transportation staff's analysis of cumulative impacts to aviation safety from the SEP's thermal plumes. Traffic and Transportation staff cannot yet complete this analysis, as they are waiting for more information on the potential infeasibility of implementing certain parts of **TRANS-9**. Land Use staff will include an analysis for cumulative impacts to land use compatibility with the Blythe Airport in the FSA, once this information is known.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the SEP PTA could potentially result in more severe land use impacts from thermal plumes, which would affect aircraft safety and make the SEP incompatible with the Blythe Airport, a surrounding land use, and the Riverside County ALUCP. Thermal plume impacts could potentially be increased due to the proposed change in technology for the SEP, and also from the potential infeasibility of implementing parts of Condition of Certification **TRANS-9**, which the 2005 Decision included to mitigate impacts to aircraft safety. See the **Traffic and Transportation** section of this PSA for more information.

The project could also result in new land use impacts from evaporation ponds by attracting birds to the site, impacting aviation safety and resulting in the project being incompatible with the Blythe Airport and Riverside County ALUCP. See the **Traffic and Transportation** section of this PSA for more information. Staff understands the project owner is currently evaluating additional options for wastewater discharge. Staff continues to recommend the ZLD process approved in the 2005 Decision, which would avoid these impacts. See the **Biological Resources** section of this PSA for more information on this recommendation.

Finally, the project could combine with the nearby BEP to cause significant cumulative impacts to aviation safety and make the project incompatible with the Blythe Airport and Riverside County ALUCP. To analyze these impacts, staff would need to rely on **Traffic and Transportation** staff's analysis of cumulative impacts to aviation safety from the SEP's thermal plumes. **Traffic and Transportation** staff does not yet have the necessary information to complete this analysis, and therefore, Land Use staff cannot yet determine whether there would be any significant cumulative impacts to land use compatibility between the project and the Blythe Airport.

A final determination of land use compatibility will be included in the FSA for Land Use.

Findings for the SEP which are consistent with the findings in the 2005 Decision are:

1. The existing zoning designations and General Plan land use designations of the project sites (including the property on which part of the new gen-tie line would be located) are compatible with the proposed uses.
2. With implementation of Conditions of Certification **LAND-3** and **LAND-6**, the SEP would not result in a significant conversion of farmland to non-agricultural use.
3. The SEP would not conflict with existing agricultural zoning or Williamson Act contracts.
4. The SEP would not disrupt or divide the physical arrangement of an established community.
5. The project changes would not impact land use by creating unmitigated air quality, noise, dust, hazardous materials, public health hazard, nuisance, or visual impacts that would result in incompatible land uses.
6. Existing Conditions of Certification **LAND-1** through **LAND-6** would remain applicable and feasible and the project owner has not requested any major changes to the conditions.

Socioeconomics Figure 1 (in the Socioeconomics section of this document) shows the presence of an environmental justice population living within the project's six-mile buffer. Staff has not identified any significant adverse direct or cumulative land use impacts to the environmental justice population resulting from the construction or operation of the proposed project. Therefore, there are no land use environmental justice impacts resulting from this project.

PROPOSED CONDITIONS OF CERTIFICATION

The Land Use conditions included in the 2005 Decision apply to the SEP, with the following caveats. In the SEP PTA, the project owner requested minor modifications to Condition of Certification **LAND-5** for clarification, as shown below in the list of conditions. Also, as discussed earlier in this section, if the project owner participates in the WCOP by means other than permanently retiring agricultural land, such as rotational fallowing, implementation of **LAND-3** would not be necessary.

In the event that dry-cooling becomes part of the SEP project description, reduced water use would mean that the project owner could retire a smaller amount of agricultural land as part of the Water Conservation Offset Program (WCOP). As a result, to fulfill the requirements of **LAND-3**, which requires that the project owner mitigate for any agricultural land permanently fallowed as part of the WCOP, the project owner would be able to pay lower mitigation fees or secure an easement for a smaller amount of agricultural land.

The Land Use conditions of certification for the SEP are listed below. Additions are shown in **<u>bold underlined</u>** text and deletions are shown in ~~strikethrough~~.

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 land designated as either Prime Farmland or Farmland of Statewide Importance as defined by the Department of Conservation (Designated Farmland), the project owner shall mitigate at a one-to-one acre ratio for the conversion of 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). 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 Designated Farmland as retired by the WCOP and/or easements within one year of start of construction as compensation for the acreage of Designated 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~~**parcel** and owned by one entity. The ~~BEP II~~**project** 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~~**parcel** for the life of the power plant.

Verification: At least 30 days prior to the start of construction, the ~~P~~**p**roject ~~O~~**o**wner 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~~**parcel** configuration to the CPM for review and approval.

LAND-6 The proposed water conservation offset program shall not retire lands in the Palo Verde Valley (Priority 1 Lands) designated as Prime Farmlands or Farmlands of Statewide Importance as defined by the Department of Conservation, or lands included in a Williamson Act Preserve. Fallowing or retirement of farmlands shall not violate any provision of a Williamson Act Contract. Lands selected for retirement on the Mesa shall not include lands currently involved in active orchard crop production.

Verification: At least 60 days prior to implementation of the Water Conservation Offset Program (WCOP), the project owner shall submit detailed information to the CPM regarding the lands involved in the WCOP, including:

1) location and assessor parcel number,
2) Department of Conservation Important Farmland Program Classification,

3) crop and cultivation history, and

4) Williamson Act Preserve and contract status.

If the program will fallow or retire any lands under Williamson Act contract, the project owner shall provide documentation that such fallowing or retirement has been reviewed and approved by Riverside County Planning Department and does not violate any provision of a Williamson Act contract.

Any WCOP agreements that are altered or added to the program shall be submitted to the CPM at least 30 days prior to taking effect.

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

ASE2015g. AltaGas Sonoran Energy Inc. Data Responses Set 1 (TN 206606). Docketed on 11/12/2015.

ASE2015i. AltaGas Sonoran Energy Inc. Data Responses Set 1 – Additional Response to Staff's Data Requests 2 and 4 (TN 207068). Docketed on 12/17/2015.

CBE2009a. Caithness Blythe Energy, Inc. Petition to Amend (TN 53798). Docketed on 10/26/2009.

CBE2010a. Caithness Blythe Energy, Inc. Modification to Amendment (TN 54662). Docketed on 1/4/2010.

CBE2010b. Caithness Blythe Energy, Inc. Amendment Supplement #1 (TN 55438). Docketed on 2/16/2010.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

CEC2012a. California Energy Commission. 2009 Petition to Amend – Staff Analysis (TN 60499). Docketed on 3/12/2012.

CEC2012b. California Energy Commission. Commission Order Approving 2009 Petition to Amend (TN 64945). Docketed on 4/26/2012.

CEC2015c. California Energy Commission. Traffic and Transportation - Record of Conversation re Blythe Airport and TRANS-9 (TN 207014). Docketed 12/15/2015.

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CB2007a – City of Blythe, General Plan and Zoning Map for City of Blythe, http://www.cityofblythe.ca.gov/DocumentCenter/View/290, approved 2007, accessed January 2016.

CB2015 – City of Blythe, Zoning Ordinance, https://www.municode.com/library/ca/blythe/codes/code_of_ordinances?nodeId=CD_ORD_TIT17ZO, accessed January 2016.

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RCALUC2004 – Riverside County Airport Land Use Commission, Riverside County Airport Land Use Compatibility Plan, adopted October 14, 2004, http://www.rcaluc.org/filemanager/plan/new//01-%20Cover%20&%20Title%20Page%20Vol%201.pdf, accessed January 2016.

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SONORAN ENERGY PROJECT (02-AFC-01C)

Petition to Amend Final Commission Decision
NOISE AND VIBRATION
Edward Brady

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) for the Sonoran Energy Project (SEP) proposes to modify the licensed Blythe Energy Project II (BEP II) project. Similar to the conclusions in the 2005 Energy Commission Final Decision (Decision) for the BEP II, the potential impacts of the proposed PTA would be less than significant. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Decision is necessary for **Noise and Vibration**. The Committee may rely upon the environmental analysis and conclusions of the 2005 Decision with regards to **Noise and Vibration** and does not need to re-analyze them.

Staff is not proposing revisions to existing Conditions of Certification **NOISE-1**, **NOISE-2**, **NOISE-3**, **NOISE-4, NOISE-5**, **NOISE-7** and **NOISE-8**. Staff recommends minor revisions to Condition of Certification **NOISE-6** below to clarify the operational noise monitoring procedures. The revised **NOISE-6** does not affect **Noise and Vibration** conclusions made in the 2005 Decision. Conditions of Certification **NOISE-1** through **NOISE-8** would be sufficient to reduce impacts from the amended project to a less than significant level and to ensure the proposed project would remain in compliance with applicable laws, ordinances, regulations, and standards (LORS) relating to noise and vibration.

INTRODUCTION

Staff has reviewed the BEPII 2005 Decision (CEC2005b) approving the originally-licensed project and the 2012 Energy Commission Order approving the 2009 amendment (Order) (CEC2012b). The 2009 amendment replaced the originally approved turbine technology (from the 2005 Decision) that was no longer available, with newer Siemens Rapid-Start turbine technology. The 2009 amendment did not affect **Noise and Vibration** as the replacement equipment was similar in scope and configuration - the 2012 Order did not address noise and vibration.

Staff has analyzed the proposed changes to the licensed BEP II, which include revising the two-on-one combined cycle power block to a one-on-one combined cycle power block that would incorporate a more efficient generating technology. The modified project would consist of one combustion turbine generator (CTG), one heat recovery steam generator (HRSG), and one steam turbine generator (STG), instead of the original project consisting of two CTGs, two HRSGs, and one STG. The petition also requests that the BEP II name be changed to Sonoran Energy Project. The following analysis evaluates the portions of the modified project that may affect the **Noise and**

Vibration analysis, findings, conclusions, and conditions of certification contained in the Decision.

SUMMARY OF THE DECISION

The 2005 Commission Decision found that the noise associated with the project's construction activities would be temporary in nature, limited in duration, and mitigated to the extent feasible, and therefore it would not result in a significant impact to the surrounding community. The Decision also found that project operation would not significantly increase the ambient noise level at the nearest sensitive noise receptor.

The Decision concluded that implementation of the staff's proposed **Noise and Vibration** conditions of certification would ensure that noise impacts would not cause any significant direct, indirect, or cumulative impacts and that the project would comply with the applicable LORS relating to noise and vibration.

As noted above, the 2009 amendment did not affect **Noise and Vibration** and the 2012 Order did not discuss this topic.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

No LORS applicable to the project have changed since the Decision was published in 2005. Additionally, the proposed amendment would not trigger new LORS that may not have been applicable to the original project.

ANALYSIS

The noise-sensitive receptor previously identified and analyzed in the Decision remains the most noise-sensitive receptor and there are no new noise-sensitive receptors in the project area since the issuance of the Decision.

CONSTRUCTION IMPACTS

The SEP's construction period and equipment and its methods of construction would be similar to the BEP II. Thus, noise impacts of the SEP's construction on the surrounding community and on the project's construction workers would be similar to the less-than-significant impacts identified in the Decision for the BEP II.

The Decision concluded that construction equipment and methods of construction would not create vibration that would be perceived by any likely receptor. Due to similar construction equipment and methods, this conclusion remains valid for the amended project.

OPERATIONAL IMPACTS

Condition of Certification **NOISE-6** in the Decision requires a noise limit of 49 dBA at the nearest residential receptor. This receptor is approximately 1.5 miles away from the project site. The changes proposed in the amendment would not affect the overall project noise at this distance and therefore the amended project would meet this limit.

Similar to the original project, the operational noise levels that may be perceived by the power plant workers would create a less-than-significant impact with implementation of Condition of Certification **NOISE-5** contained in the Decision.

Based on experience with several previous projects employing similar power block equipment as those proposed for the SEP, and similar to the BEP II, staff believes vibration from the SEP would be undetectable by any likely receptor.

Staff's **Soil and Water Resources** analysis recommends a dry-cooled system as an alternative power plant cooling system to the approved wet-cooled system (CEC2005b). This alternative would substitute the project's wet cooling tower with an air-cooled condenser. This change may slightly increase the noise level produced by the equipment within project boundaries, but it would not affect the nearest residential receptor, approximately 1.5 miles away from the project site.

No further analysis is needed due to the following reasons.

- The changes in the amendment would not create new significant environmental impacts or substantial increases in the severity of previously identified significant impacts.
- The amendment does not propose substantial changes which would require major revisions of the **Noise and Vibration** analysis contained in the Decision.
- The circumstances under which the amended project would be undertaken would not require major revisions of the **Noise and Vibration** analysis contained in the Decision.

CUMULATIVE IMPACTS

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. Only one project was identified in the staff's updated cumulative project list that could potentially contribute to cumulative noise and vibration impacts. This is the Blythe Mesa Solar Power Project (Blythe Mesa), a 485 MW solar photovoltaic facility that would be located within one mile of the SEP site. However, both project sites are too far away from the surrounding community (approximately 1.5 miles away) to create a significant cumulative noise and vibration impact.

CONCLUSIONS AND RECOMMENDATIONS

Existing Conditions of Certification **NOISE-1**, **NOISE-2**, **NOISE-3**, **NOISE-4, NOISE-5**, **NOISE-7**, and **NOISE-8** and the proposed minor revisions to Condition of Certification **NOISE-6** would be sufficient to reduce impacts from the proposed amendment to a less than significant level directly, indirectly, and cumulatively and to ensure the project remains in compliance with applicable LORS relating to noise and vibration. The revised **NOISE-6** does not affect **Noise and Vibration** conclusions made in the 2005 Decision.

PROPOSED CONDITIONS OF CERTIFICATION

The amendment requests additional text to **NOISE-6** (ASE2015a, § 3.7.6) to clarify the application of the numeric noise limit and the operational noise monitoring procedures. Staff has no concerns with these additions and has revised **NOISE-6** accordingly. New text is **<u>bold and underlined</u>**.

NOISE-1 At least 15 days prior to the start of 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 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 Complaint Resolution Form, 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 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 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 At least 15 days 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: Within five (5) days of notifying these entities, the project owner shall send a letter to the CPM confirming that residences and businesses 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 **<u>any existing</u>** 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.

Within 30 days of the project's 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. 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. If the results from the noise survey indicate that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

<u>The measurement of power plant noise for the purposes of demonstrating compliance with this condition of certification may alternatively be made at a location, acceptable to the CPM, closer to the plant (e.g., 400 feet from the plant boundary) and this measured level then mathematically extrapolated to determine the plant noise contribution at the affected residence. The character of the plant noise shall be evaluated at the affected residential locations to determine the presence of pure tones or other dominant sources of plant noise.</u>

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's 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 below:

- High-pressure steam blows: 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.
- 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.

REFERENCES

ASE2015a – AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CEC2012b. California Energy Commission. 2012 Commission Order Approving 2009 Petition to Amend (TN 64945). Docketed on 4/26/2012.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
PUBLIC HEALTH ANALYSIS
Obed Odoemelam, Ph.D.

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) for the Sonoran Project (SEP) proposes project modifications that would eliminate one of the project's two **Public Health** Conditions for Certification. Similar to the conclusions in the project's licensed Blythe Energy Project Phase II (BEP II) 2005 Energy Commission Final Decision (2005 Decision), the potential impacts of the toxic pollutants of concern in this analysis would be less than significant. Staff has evaluated the validity of the owner's health risk assessment and established that the proposed technological modification would not affect SEP's ability to comply with applicable health laws, ordinances, regulations, and regulations (LORS). Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Decision is necessary for **Public Health**. Staff recommends approval of the owner's request to delete Condition of Certification **PUBLIC HEALTH-1** which would be rendered unnecessary from implementation of the cooling tower Conditions of Certification (**AQ-43** through **AQ-49**) in the **Air Quality** section of this document. If dry cooling were to be utilized, **PUBLIC HEALTH-2** would not be necessary and staff would also recommend its deletion. Staff does not anticipate any other changes to the public health analysis with the incorporation of dry cooling.

INTRODUCTION

The purpose of this **Public Health** analysis is to determine whether or not the toxic air pollutants from the Commission-permitted BEP II, as modified into the SEP, would have the potential for significant health impacts during construction and operation. The project was approved in 2005 with two **Public Health** Conditions of Certification. The PTA proposes to rename the project from BEP II to the SEP The owner applied for an amendment on October 23, 2009 and the Commission approved it on April 27, 2012 (2012 Order) with the same two Conditions of Certification that it had specified for BEP II in the 2005 Decision. Since the risks from construction and operation reflect the effectiveness of the implemented emission control measures, approval means acceptance of the adequacy of these measures. The same **Air Quality** section control measures are presently proposed for SEP and staff is assessing the validity of the owner's assessment of the health risks from construction and operation.

SUMMARY OF THE DECISION

The Energy Commission concluded in the 2005 Decision (CEC 2005b) that the design and operational plan for BEP II project would maintain the emitted toxic pollutants below levels of public health significance. The Energy Commission then sought to ensure implementation of the proposed emission measures by specifying Conditions of Certification **PUBLIC HEALTH-1** and **PUBLIC HEALTH-2** that staff had recommended.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

There have been no changes to the health-related LORS of concern to staff since the Energy Commission's Decision on BEP II was published in December, 2005.

ENVIRONMENTAL IMPACT ANALYSIS

CONSTRUCTION

The construction-phase impacts of concern to staff are those from human exposure to windblown dust from site excavation and grading, and from emissions from diesel-fueled construction equipment. The owner has specified mitigation measures against such wind-blown dust as required by Mojave Desert Air Quality Management (MDAQMD) rules. Implementation of these measures would be assured for SEP through specific Conditions of Certification in the **Air Quality** section.

The exhaust from the diesel-fueled equipment is capable of carcinogenic effects and is minimized through specific control measures. The Energy Commission assessed these mitigation measures for BEP II in the **Air Quality** section (as **AQ-C3**, **AQ-C4** and **AQ-C5**, now **AQ-SC3**, **AQ-SC4** and **AQ-SC5**) and found them adequate for minimizing the cancer and non-cancer impacts of concern. The owner proposes the same control measures for SEP's proposed 22-month construction period. Staff considers these measures adequate as incorporated into specific conditions of certification in the **Air Quality** section and does not recommend additional mitigation measures in this **Public Health** section.

OPERATION

As more fully presented in the **Project Description** section, the proposed SEP is a facility with technological improvements over the Energy Commission-approved BEP II. The main health risk from operations would be associated with emissions from its combustion turbine, emergency diesel fire pump engine, and the evaporative cooling tower. In addition to particulate matter emissions from the cooling tower discussed in the **Air Quality** section, there is specific concern over the risk of Legionnaires' disease from bacterial growth. Staff supports the mitigation requirement as specified in Condition of Certification **PUBLIC HEALTH-2** against bacterial growth but recommends deletion of **PUBLIC HEALTH-1**, which would be rendered unnecessary from implementation of the cooling tower Conditions of Certification (**AQ-43** through **AQ-49**) in the **Air Quality** section of this document. Should the project be approved with dry cooling as staff is suggesting, both **PUBLIC HEALTH-1** and **PUBLIC HEALTH-2** would be rendered unnecessary and staff would recommend deletion of both conditions.

CONCLUSIONS AND RECOMMENDATIONS

The cancer and non-cancer risks from SEP operations are presented in **Public Health Table 1.** As shown in the table, all the risk values are significantly below their respective significance thresholds meaning that the proposed project modifications would not result in significant public health impacts during operations.

Public Health Table 1
Operation Hazard/Risk at Point of Maximum Impact

Type of Hazard/Risk	Hazard Index/Risk	Significance Level	Significant?
Acute Non-cancer	0.024	1.0	No
Chronic Non-cancer	0.003	1.0	No
Individual Cancer	1.5 in one million	10 in one million	No

Source: ASE2015, p. 3-124.

PROPOSED CONDITIONS OF CERTIFICATION

Since the proposed SEP would be designed with emission controls maintaining any related cancer and non-cancer risks below significance levels, staff does not recommend additional mitigation measures. Staff considers the cooling tower-related Conditions of Certification in the **Air Quality** section as adequate to minimize any health impacts and recommends deletion of the related Condition of Certification (**PUBLIC HEALTH-1**) in this **Public Health** section as the project owner requests. If the owner were to utilize dry cooling in the facility, the cooling water treatment would not be necessary and staff would also recommend deleting **PUBLIC HEALTH-2**.

~~**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 Water Management 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.

REFERENCES

ASE2015a—AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CEC2005a—California Energy Commission. Final Staff Assessment. Docketed 4/29/2005.

CEC2005b—California Energy Commission. Final Commission Decision. Docket on 4/26/2015.

SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
SOCIOECONOMICS
Ellen LeFevre

SUMMARY OF CONCLUSIONS

Staff concludes that the proposed amendment would have no new socioeconomic impacts and the mitigation for the Blythe Energy Project Phase II (BEP II) would still be applicable and would not require any substantive changes. Staff also concludes that the findings of the licensed BEP II 2005 California Energy Commission (Energy Commission) Decision (2005 Decision), and 2012 Order approving the 2009 Amendment (2012 Order) would still apply to the amended Sonoran Energy Project (SEP). Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Commission Decision is necessary for Socioeconomics. The Committee may rely upon the environmental analysis and conclusions of the 2005 Commission Decision with regards to Socioeconomics and does not need to re-analyze them.

In the event dry-cooling becomes part of the SEP project description, the existing Condition of Certification **SOCIO-2** would no longer be necessary.

INTRODUCTION

Staff has reviewed the 2005 Decision and analyzed the proposed changes to the BEP II which include a new point of electrical interconnection, and changes to the approved, but not built, turbines, steam turbine generator, and cooling tower. The current Petition to Amend (PTA) also requests the BEP II name be changed to Sonoran Energy Project.

SUMMARY OF THE DECISION

Based on the evidence presented in the original proceeding, the Energy Commission found that the project would not cause a significant adverse direct or cumulative impact on housing, employment, schools, public services, or utilities. The project would have a temporary benefit to the city of Blythe and adjacent areas in terms of an increase in local jobs and commercial activity during the construction of the facility. The construction payroll and project expenditures would also have a positive effect on local and county economies. The estimated benefits from the project include increases in the affected area’s property and sales taxes, general employment, and sales of services, manufactured goods, and equipment. The project conforms to applicable laws related to socioeconomic matters and all potential socioeconomic impacts will be insignificant.

The subsequent 2012 Order concluded that the proposed changes will not result in any significant impact to public health and safety, or the environment.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

No socioeconomics LORS applicable to the project have changed since the 2005 Decision.

ENVIRONMENTAL IMPACT ANALYSIS

In accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Commission Decision is necessary for Socioeconomics. The Committee may rely upon the environmental analysis and conclusions of the 2005 Commission Decision with regards to Socioeconomics and does not need to re-analyze them due to the following:

- The changes in the PTA would not create new significant workforce-related impacts on housing and community services or substantial increases in the severity of previously identified significant effects.
- The PTA does not propose substantial changes which would require major revisions of the Socioeconomics analysis in the 2005 Decision.
- The circumstances under which the amended SEP would be undertaken would not require major revisions of the Socioeconomics analysis in the 2005 Decision.

Staff's conclusion is supported by the following key factual information:

- No laws, ordinances, regulations, and standards (LORS) applicable to socioeconomics have changed since the 2005 Decision.
- The construction workforce is reduced from a peak of 387 workers to a peak of 325 workers. The average number of construction workers is reduced from 255 workers to 164 workers.
- The operations staff is reduced from 20 employees to nine employees.
- The construction period has increased 20 months to 26 months, which includes four months of commissioning.
- Construction workers would be drawn from Riverside County Metropolitan Statistical Area (MSA) and regionally from the Imperial County Metropolitan Statistical Area (MSA) and San Diego County Metropolitan Statistical Area (MSA) instead of Las Vegas, Yuma, and Phoenix.
- Existing Conditions of Certification **SOCIO-1**, **SOCIO-2**, and **SOCIO-3** would remain applicable and feasible and the project proponent, Altagas Sonoran, has not requested any changes to these conditions.

The project site is a 76-acre parcel located within the city of Blythe, in eastern Riverside County. During the project construction the "local workforce" residing within a two hour commute includes Riverside-San Bernardino-Ontario MSA (Riverside County), El Centro MSA (Imperial County), and San Diego-Carlsbad MSA (San Diego County). During project operation the “local workforce” residing within a one-hour commute of the project includes Riverside-San Bernardino-Ontario (Riverside County) MSA.

The petition proposes a modification to the construction schedule and workforce. The SEP project construction is anticipated to last 26 months, including 4 months of commissioning, from June 2016 (Quarter 2) until July 2018 (Quarter 3) with commercial operation anticipated in the second quarter 2018 (ASE2015a, pg. 2-9). The average workforce over the 22 month construction period would be 164 workers and would peak in months 11 and 12 (April - May 2017) with 325 workers. The number of construction workers would be reduced from the licensed BEP II which had a peak of 387 workers. The length of construction would increase slightly from 20 months to 26 months, including commissioning.

The construction plan is based on a single 10 hour shift/6 days per week. Overtime and additional shift work may be used to maintain or enhance the construction schedule. The majority of construction operations are expected to take place between 6:00 a.m. and 6:00 p.m., Monday through Saturday. However, additional hours may be necessary to maintain schedule or to complete critical construction activities (such as large concrete pours). During the commissioning and startup phase, some activities may continue 24 hours per day, 7 days per week (ASE2015a, pg. 2-9).

Project construction activities would require an onsite laydown area (approximately 13.5 acres) for the equipment storage and construction workforce parking. Additional room onsite would be allocated for staging and construction trailers (ASE2015a, pg. 2-9).

The petition proposes a modification to the number of operational employees. The SEP project would require nine operation and maintenance workers compared to the 20 previously analyzed for the licensed BEP II.

The construction cost of the project would be approximately $443.6 million, of which approximately $45.3 million would be construction payroll and approximately $67.6 million would be for local product purchases (ASE2015a, p. 3-132). The total tax revenue from the sale of local products during construction would be approximately $5.4 million and would comply with Condition of Certification **SOCIO-3.**

The Condition of Certification **SOCIO-2** was adopted in the 2005 Commission Decision to mitigate the loss of farm labor jobs from the Water Conservation Offset Program to retire or fallow lands within the Palo Verde Irrigation District’s service area that are or have been irrigated within the past five years. In the event dry-cooling becomes part of the SEP project description, the existing Condition of Certification **SOCIO-2** would no longer be necessary.

The proposed amendment would have no workforce-related impacts on housing and community services and would not result in a change or deletion of the Conditions of Certification **SOCIO-1**, **SOCIO-2**, and **SOCIO-3** adopted in the 2005 Decision.

CUMULTATIVE 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 (CEC 2005b, p. 164).

Despite recent and proposed development of solar projects near the city of Blythe and along the I-10, there is no shortage of available skilled construction labor in the Riverside, Imperial, and San Diego County MSAs. No lodging and housing shortages are expected due to the construction of the SEP. The project's slight increase in population during construction would not create a significant reduction in the lodging and housing supply. The number of employees required for operation would not cause a significant impact on the local labor force. The project in combination with past, present, and reasonably foreseeable projects in the area would not be cumulatively considerable. Therefore, the construction and operation of the SEP would not result in any significant cumulative impacts to housing and construction availability.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the proposed amendment would have no new socioeconomic impacts and the mitigation for the original project would still be applicable and would not require any substantive changes. Therefore, staff also concludes that the findings of the licensed BEP II Commission Decision would still apply to the amended SEP.

The project would not cause a significant adverse direct or cumulative impact on housing, employment, schools, public services or utilities. The project would have a temporary benefit to the city of Blythe and adjacent areas in terms of an increase in local jobs and commercial activity during the construction of the facility. The construction payroll and project expenditures would also have a positive effect on local and County economies. The estimated benefits from the project include increases in the affected area's property and sales taxes, general employment, and sales of services, manufactured goods, and equipment.

The project conforms to applicable laws related to socioeconomic matters and all potential socioeconomic impacts will be insignificant.

The Condition of Certification **SOCIO-2** was adopted in the 2005 Commission Decision to mitigate the loss of farm labor jobs from the Water Conservation Offset Program to retire or fallow lands within the Palo Verde Irrigation District's service area that are or have been irrigated within the past five years. In the event dry-cooling becomes part of the SEP project description, the existing Condition of Certification **SOCIO-2** would no longer be necessary.

Socioeconomics Figure 1 shows the presence of an environmental justice population living in the project's six-mile radius. Staff has not identified any significant adverse direct or cumulative socioeconomic impacts resulting from the construction or operation of the proposed project, including impacts to the environmental justice population. Therefore, the proposed project would not affect any population including the Environmental Justice population as shown in **Socioeconomics Figure 1.**

CONDITIONS OF CERTIFICATION

Existing Conditions of Certification **SOCIO-1, SOCIO-2, SOCIO-3** will be sufficient to reduce impacts from the proposed amendment to a less than significant level, and ensure the project remains in compliance with applicable LORS. Therefore, staff does not propose any modifications to the existing conditions of certification.

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 The project owner shall prepare a plan to address the farming sector economic impacts from the WCOP. The Applicant shall create a $198,000 fund to implement plan measures. The project owner's proposed $120,000 contribution to the community college may be credited toward that amount.

Verification: The project owner shall submit the plan to the CPM for review and approval at least six months prior to commercial operation. The plan shall contain, at a minimum, the specific activities to implement and a description of how each plan will be funded.

SOCIO-3 The project owner and its contractors and subcontractors shall recruit employees and procure materials and supplies within the Blythe Area, unless:

- To do so will violate federal and/or state statutes;
- The materials and/or supplies are not available;
- Qualified employees for specific jobs or positions are not available; or
- There is a reasonable basis to hire someone for a specific position from outside the local area.

Verification: At least five days prior to the start of construction, the project owner shall submit to the Energy Commission Compliance Project Manager (CPM) copies of guidelines stating hiring and procurement requirements and procedures.

In addition, the project owner shall notify the Energy Commission CPM in each Monthly Compliance Report of any procurement of materials or hiring outside the local regional area that has occurred during the previous month. The Energy Commission CPM shall review and comment on the submittal as needed.

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

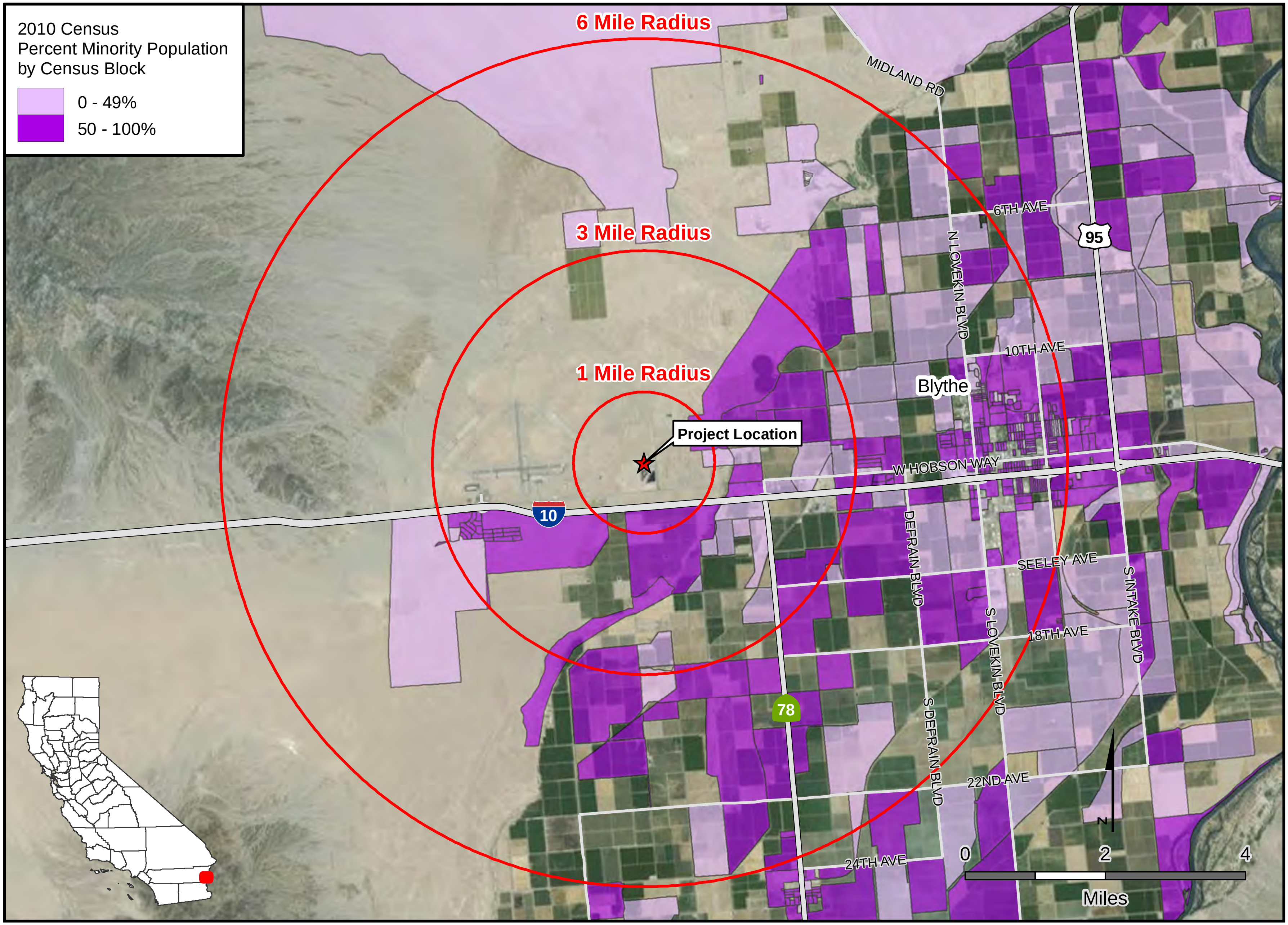
CA EDD 2015 – Employment Development Department, State of California, Labor Market Information, *Projections of Employment by Industry and Occupation, 2010-2020 Occupational Employment Projections for Riverside-San Bernardino-Ontario MSA (Riverside and San Bernardino Counties), El Centro MSA (Imperial County), and San Diego-Carlsbad MSA (San Diego County,* December 2014 and January 2015, <http://www.labormarketinfo.edd.ca.gov/data/employment-projections.html#Proj>.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

SOCIOECONOMICS - FIGURE 1

Sonoran Energy Project - Census 2010 Minority Population by Census Block



SOCIOECONOMICS

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Census 2010 PL 94-171 Data

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SONORAN ENERGY PROJECT (02AFC-1C)

Petition to Amend Final Commission Decision
SOIL & WATER RESOURCES
Mike Conway

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Sonoran Energy Project (SEP) does not seek to modify the existing **Soil & Water Resources** Conditions of Certification, but staff is recommending modifications for reasons outlined below in the analysis. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that a supplementation to the Blythe Energy Project Phase II (BEP II) 2005 Commission Decision (2005 Decision) is necessary for **Soil & Water Resources**. The Committee should re-analyze the conclusions of the 2005 Decision alongside this new information.

In this section, staff augments the existing record to reflect current environmental conditions and updated policy considerations. Similar to staff conclusions during the licensing of the BEP II project in 2005, staff believes the SEP should implement dry cooling to address project water use impacts. In addition to the project's use of wet-cooling not complying with state water policy, the Palo Verde Mesa basin is now supporting unsustainable groundwater pumping. The additional groundwater demand required by the SEP would be expected to result in significant impacts to the Palo Verde Mesa groundwater basin and flows in the Colorado River.

The SEP would rely on groundwater and irrigation water that is destined for the Colorado River. Staff is concerned that the projected decrease in Colorado River flows in the future could impact the SEP's reliability. Staff does not believe that an unmetered take from the Colorado River is sustainable. In the recent past, pumpers of Colorado River water were expecting to fall under the Accounting Surface Rule. In the more recent past, many power plants in California have struggled to maintain reliable water supplies when facing competing uses, changing California weather patterns, and local and regional droughts.

The use of high quality groundwater for cooling is highly discouraged by state water policies both old and new. Since the 2005 Decision, the Sustainable Groundwater Management Act (SGMA) has been adopted. This law requires sustainable management of California groundwater basins. The SEP would put the Palo Verde Mesa further into an unsustainable condition.

The project owner has not produced meaningful evidence they can develop and implement a Water Conservation Offset Plan (WCOP) that would offset project groundwater use in accordance with the 2005 Decision. Staff is concerned that the owner would have great difficulty achieving the necessary offset. The 2005 Decision states, "To avoid potential environmental impacts, the WCOP needs to include measures to protect from erosion and to verify true water conservation from qualifying farmlands." Since 2005, farmlands available for water offset have become scarce in the

Palo Verde area; many pieces of land have already been purchased for this purpose by Metropolitan Water District (MWD). Staff is also concerned that there may not be enough fallow-able land available on the Palo Verde Mesa or Valley to meet the project's needs. The cost to produce a commensurate offset could also be cost prohibitive for the owner. Staff concludes that since it is unlikely the project owner can demonstrate there is real water savings that would benefit the basin and the river, the project owner should be required to implement a dry cooled design.

The Energy Commission staff-prepared Water Supply Assessment (WSA) indicates that the water supply of the Palo Verde Mesa basin cannot support the SEP. The project also cannot comply with state water policy due to its high water demand and use of high quality water. It is unreasonable to permit such excessive water use when other feasible and economical technologies exist. It is important to note that efforts are being made all along the Colorado River to conserve water resources and augment supplies. Conservation will be necessary to meet the future needs of the river (USBR2012).

Staff recommends that the SEP be modified to incorporate dry-cooling. Though the proposed use of water is not currently regulated under the Accounting Surface Rule, it is not adequately reliable, and it is not adequately drought-proof. A dry-cooled version of the project would still be expected to be profitable and meet the project's objectives.

Staff suggests minor revisions to some of the Conditions of Certification. **Soil & Water Table 1** summarizes the changes proposed by staff. Some of the conditions could require additional modification if the project were to switch to dry-cooling.

Soil & Water Resources Table 1
Summary of Proposed Modifications to Conditions of Certification

Original Condition of Certification	Revised Condition of Certification	Proposed Modification(s) to Condition
WATER QUALITY-1	**SOIL&WATER-1**	CONSTRUCTION SWPPP: No substantial changes necessary.
WATER QUALITY-2	***ELIMINATED***	DRAINAGE, EROSION, AND SEDIMENT CONTROL PLAN: This condition is no longer needed. Its intent is met by SOIL&WATER-1 and -2.
WATER QUALITY-3	**SOIL&WATER-2**	INDUSTRIAL SWPPP: No substantial changes necessary.
WATER QUALITY -4	**SOIL&WATER-3**	SEPTIC SYSTEM: No changes necessary.
WATER QUALITY-5	**SOIL&WATER-4**	ZERO LIQUID DISCHARGE SYSTEM: No changes suggested at this time. This condition might need revising if the project switches to dry-cooling.
WATER QUALITY-6	**SOIL&WATER-5**	GROUNDWATER TESTING: No changes suggested at this time. This condition might need revision when the project switches to dry-cooling.
WATER QUALITY-7	**SOIL&WATER-6**	EVAPORATION POND PERMITTING: No changes suggested at this time. This condition might need revising when the project switches to dry-cooling.
WATER RES-1	**SOIL&WATER-7**	WATER CONSERVATION OFFSET PLAN: Modified language to reflect staff's recommendation to use less water. Staff chose 280 acre-feet per year as the expected use at a dry-cooled version of the project. This is equal to one-tenth of the currently permitted use (2,800 acre-feet per year).
WATER RES-2	**SOIL&WATER-8**	GROUNDWATER METERING: No changes suggested at this time. This condition might need revising when the project switches to dry-cooling.
WATER RES-3	**SOIL&WATER-9**	WELL INTERFERENCE MITIGATION: No changes suggested at this time. This condition might need revising when the project switches to dry-cooling.
WATER RES-4	**SOIL&WATER-10**	ANNUAL WATER USE LIMIT: Staff proposes a limit that is one-tenth the licensed water use limit. This change approximates the use that could be required by a dry-cooled version of the project.
WATER RES-5	**SOIL&WATER-11**	WATER METERS: No changes necessary.
WATER RES-6	**SOIL&WATER-12**	FIRST YEAR WATER USE REPORTING: No changes necessary.
WATER RES-7	**SOIL&WATER-13**	ANNUAL WATER USE REPORTING: No changes necessary.

INTRODUCTION

In this section, Energy Commission staff discusses potential impacts of the proposed amendment on **Soil & Water Resources** (See original Commission Decision for the project at http://www.energy.ca.gov/2005publications/CEC-800-2005-005/CEC-800-2005-005-CMF.PDF). The SEP was originally licensed as the 520-megawatt (MW) Blythe II project in 2005. The project went through a minor amendment in 2012 (2012 Order) and a transfer in ownership in 2014. In 2014, Caithness Blythe II, LLC sold the project to AltaGas Sonoran Energy Inc. In 2015, AltaGas Sonoran submitted a PTA for the newly named SEP. The amended SEP would replace the previously proposed Siemens combustion turbines with a single and more efficient General Electric (GE) 7HA.02 combustion turbine, but still utilize wet-cooling and require up to 2,800 acre-feet per year (AFY) of groundwater.

SUMMARY OF THE DECISION

In this section staff summarizes the 2005 Decision and 2012 Order. This summary is not intended to endorse the findings in the previous Decisions, but to inform the reader by providing necessary background information. The 2005 Decision devoted substantial discussion to staff and applicant positions about the appropriateness of the project's use of groundwater for wet-cooling in the context of state water policy.

In the 2005 Decision, the Commission stated that the quality of water to be used by the project was of marginal quality, based on State Water Board Resolution 75-58 and the availability of alternative water supplies. The Decision reviewed the feasibility of using recycled water from the City of Blythe, Rannells Drain return water from Palo Verde Irrigation District, and dry cooling. The Commission concluded recycled water was an infeasible alternative due to insufficient supply. The Rannells Drain water was also considered an unreasonable supply due to its high quality and lack of conformance with Resolution 75-58. Dry-cooling was found to be technologically feasible, but not practically feasible. The Commission believed dry-cooling was inefficient for a project requiring many start-ups in the hot desert environment. Dry-cooling was also said to create "substantially worse noise, visual, and thermal plume impacts (at the Blythe airport) than wet-cooling." The evidence led to their conclusion that the project's proposed use of groundwater for wet-cooling would conform to both Resolution 75-58 and the Energy Commission's 2003 Integrated Energy and Policy Report (IEPR) water policy and therefore be acceptable for use.

Important considerations about the hydrology of the Palo Verde area were provided by staff, applicant, and Palo Verde Irrigation District (PVID) and included in the 2005 Decision. The Decision documents that PVID's diversion of 913,000 AFY and return of 513,000 AFY through Rannells drain, supports most of the water use in the area. The Decision shows how groundwater withdrawal by the project would ultimately capture water from Rannells drain and therefore reduce PVIDs return flow to the river. In this vein, the Decision documents how most of the groundwater pumping in the Palo Verde region is ultimately replaced by Colorado River water. The Decision also concludes that the United States Bureau of Reclamation (USBR) does not regulate groundwater withdrawals from aquifers recharged by the Colorado River and that there is no law prohibiting the project's use of groundwater.

The Decision contains a discussion of potential groundwater quality impacts that could occur as a result of project operation. The Commission found that the upwelling of deeper groundwater caused by project pumping, could induce the flow of more saline water into the aquifer. This upwelling was expected to create some water quality degradation, but its impact was said to be insignificant and mitigable.

The Decision accepted the owner's proposal for a voluntary Water Conservation Offset Plan (WCOP). The Commission expressed its interest that the WCOP be effective and "not just window-dressing on the project." The Decision also states, "The Commission is concerned that the WCOP actually produces a true offset of the project's water use." The Decision documents substantial discussion regarding what constitutes fallow-able land for the purposes of the WCOP. These concerns along with the concern for erosion occurring on fallowed land left unattended, was the basis for Condition of Certification **WATER RES-1**.

The 2005 Decision also included conditions of certification that would insure no adverse impacts to stormwater quality during construction and plant operation. A condition was also included to require the project to utilize Zero Liquid Discharge (ZLD) technology, instead of using wastewater ponds. Other conditions include an annual water use limit and water metering and reporting.

In 2012 the Commission approved an amendment for the project that limited its water use to 2,800 AFY. The previously approved maximum use of up to 3,300 AFY was deemed unnecessarily high for the reasonably expected operational conditions.

The Conditions of Certification included at the end of this analysis would ensure that impacts to Soil and Water Resources are mitigated to a level that is less than significant.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

New LORS that would apply to SEP are discussed in Soil & Water Resources Table 2 below.

Soil & Water Resources Table 2
Updated Laws, Ordinances, Regulations, and Standards

Applicable LOR	Description
State	
California Water Code Sections 10910-10915	Requires public water systems to prepare water supply assessments (WSA) for certain defined development projects subject to the California Environmental Quality Act. Lead agencies determine, based on the WSA, whether projected water supplies will be sufficient to meet project demands along with the region’s reasonably foreseeable cumulative demand under average-normal-year, single-dry-year, and multiple-dry-year conditions.
Executive Orders No. B-28-14 and No. 29-15	These Governor’s Executive Order stress the importance of efficient use of water and require various state agencies to help expedite the approval and construction of water conservation projects.
Sustainable Groundwater Management Act (SGMA), California Water Code Sections 5202, 10540, 10720.1, 10722.4, 10750	Collectively known as the Sustainable Groundwater Management Act (SGMA), these code sections provide for the formation of Groundwater Sustainability Agencies, development of plans for sustainable management of groundwater basins, establish minimum requirements for groundwater basin management, and prevent undesirable results in a groundwater basin from unsustainable extractions. Where necessary the state may intervene to ensure basins are managed in accordance with minimum criteria.

ENVIRONMENTAL IMPACT ANALYSIS

Stormwater would be managed similar to the original licensed project. Renamed and revised Conditions of **SOIL&WATER–1** and **SOIL&WATER–2** would ensure the project complies with LORS that would ensure there are no water quality impacts from project construction or operation, respectively.

Sanitary wastewater would also be managed similar to the original licensed project. Renamed Condition of Certification **SOIL&WATER–3** would ensure the project owner designs and operates the septic system so that complies with County and City standards and prevent any adverse impacts to water quality and public health.

Renamed Condition of Certification **SOIL&WATER–4** would require the project owner to use a Zero Liquid Discharge (ZLD) system to significantly reduce the volume of industrial wastewater that would have been generated by BEP II because of the wet-cooled design that was approved. The original license also permitted the use of small evaporation ponds for intermittent use when there were interruptions in use of the ZLD. The PTA suggests however, that the project owner proposes only use of evaporation ponds rather than a ZLD for disposal of industrial wastewater. The original license specifically excluded use of only evaporation ponds for disposal. The PTA does not include any discussion of why this change was made. Staff understands the project owner has been made aware of this lack of supporting information and will provide additional information explaining what they propose and what, if any, changes are needed to the project description so staff can complete the necessary analysis and preparation of the final staff assessment. In the analysis of water supply below, staff is proposing dry-cooling to reduce the use of water because of the state's water policy, the unsustainable groundwater pumping, and the staff-prepared WSA, which indicates the water supply of the Palo Verde Mesa basin cannot support the SEP. Using dry cooling would substantially reduce water use and the amount of wastewater produced by the SEP because it would eliminate discharges of wet cooling tower blow-down water. This reduction in wastewater volume might also reduce or eliminate the need for ZLD and large evaporation ponds. If the project owner still proposes to use evaporation ponds then they should be required to comply with **SOIL&WATER-6** which would ensure there are no releases of wastewater from project operation that would result in water quality impacts.

WATER SUPPLY

The project owner proposes to pump up to 2,800 acre feet per year (AFY) from the Palo Verde Mesa groundwater basin.

This water supply would be used for both potable and industrial uses. The 2005 Decision did not require a limit on groundwater pumping. Information on the project at that the time indicated the design would require up to 3,300 AFY for wet cooling and other operational uses. In the 2012 Decision, Energy Commission adopted limits on groundwater use of up to 2,800 AFY based on staff's further analysis of water use given typical operating scenario's. The project owner should be required to comply with Conditions of Certification **SOIL&WATER-8** and **SOIL&WATER-11** through **-13** to ensure metering and reporting of any water use which would demonstrate compliance with project water use limits proposed in Condition of Certification **SOIL&WATER-10**.

Staff proposes changes to Condition of Certification **SOIL&WATER-10** because environmental conditions and LORS have changed with respect to water supply in California and at power plants since the adoption of the 2005 and 2012 Decisions. Staff presents updated analysis of these changed water supply conditions below.

Colorado River

The 2005 Decision discussed the concern staff had about the Accounting Surface Rule applying to the project in the future. The status of this rulemaking has not changed and staff is not aware of any new laws regarding groundwater use restrictions along the Colorado River. Staff is not convinced however that the project would not be subject to new restrictions in the future, resulting in diminished project availability. The Colorado River is completely allocated and supply shortages are expected in the future (USBR2012).

In December 2012, the USBR published a WSA for the Colorado River Basin. The report contains the results of modeling efforts intended to estimate how future flow in the river would compare to the mean flow observed between the years 1906 and 2007. The modeling results indicate that the average flow between years 2011 and 2060 is expected to decrease 1 to 8.7-percent, or 150,000 AFY to 1,305,000 AFY, respectively (USBR 2012).

Staff is concerned that the SEP would ultimately induce flow from the neighboring Palo Verde Valley basin, via the Rannells Drain, which is hydraulically connected to the Colorado River. This unlined drainage feature functions as both an irrigation canal (bringing water from the river) and a drainage canal (returning water to the river). Where the canal loses its flow to the subsurface, the groundwater system gains additional supply. Pumping from the project would be expected to increase the gradient between the project and Rannells Drain and therefore induce more flow to the groundwater basin. While some of the project's water would be supplied by groundwater flow from the west, the water coming from the drain would be expected to be more significant (CEC 2005). This is generally because the supply from the west is limited by recharge and underflow from the neighboring basins, while the water from Rannells Drain would act as an infinite source. Since the Rannells Drain otherwise flows to the Colorado River, flows to the River would ultimately be reduced as a result of project pumping.

Though the water used at the project would come from the Colorado River and may not currently be a regulated take from the river, staff questions the project's water supply sustainability and reliability. The SEP's pumping would have been regulated by the proposed Accounting Surface Rule, which would have required the SEP to obtain an entitlement for use (FedReg 2008). How or whether or not an entitlement could be obtained is not known. Staff is concerned that the proposed rule-making could be re-proposed or finalized during the SEP's operational lifetime. PVID has a right to divert water for irrigation purposes within their service area, but staff does not to see how this right would protect the project's use of water that is outside of PVID's service area. If the SEP's use was specifically permitted or accounted-for with the PVID system, staff would believe that the project's use would have a reliable path towards receiving an entitlement if necessary.

A WCOP could work towards a sustainable and reliable future. For instance, in some cases, land within the PVID service area is fallowed and the water saved is sold to Metropolitan Water District (MWD). If the SEP were to fallow farmlands that have a permitted use within the PVID system, staff would have confidence that its use would be accounted for and recognized as legitimate. Staff is concerned that because the water pumped for use by the SEP is not specifically being allocated for or being offset by a formal water exchange agreement, it does not have a secure or justifiable future. As discussed in the following sections, staff believes the SEP should switch to dry-cooling to increase the project's reliability and its sustainability of operation in the Palo Verde region.

Water Policy

Central to the interpretation of state water policy is the appropriateness of the water use in the context of competing uses. Water resources of the state should be put to beneficial use to the fullest extent practicable (Cal. Const., art. X, § 2.). The State Water Board reiterates the state's intent and its relation to power plant water use in Resolution 75-58, stating that fresh inland waters should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound. The California Energy Commission specified in the *2003*

Integrated Energy Policy Report (IEPR), would approve the use of fresh water for cooling purposes by power plants it licenses only where alternative water supply sources and alternative cooling technologies are shown to be environmentally undesirable or economically unsound. However, contrary to this policy, the 2005 Decision states, "post-irrigation drain water to be returned to the River contains mostly fresh water, which is highly disfavored for power plant cooling, and its use would immediately decrease supplies available to downstream water users." Staff's current conclusion is similar, the project's unnecessarily high use of water for cooling would be impacting downstream, competing users and would be inconsistent with state water policy.

Staff reviewed recent project Decisions and agency communications to inform the current staff stance on the water policy. Since the 2005 Decision, staff consulted with the State Water Resources Control Board about the interpretation of Resolution 75-58. The result of that consultation forms the belief that the water quality constituent threshold of 1,000 mg/L total dissolved solids (TDS) discussed in the 2005 Decision is not intended to apply to groundwater.

> *"The Water Board Letter supports consideration of site specific factors and further indicates that while the 1,000 mg/L TDS standard may be one of the factors that apply to a determination about the suitability of surface water use, it does not apply to groundwater use."* (Genesis2010)

This consultation with the Board provides some additional perspective for considering the appropriateness of the project's proposed groundwater use. The 2005 Decision relied on the 1,000 mg/L TDS threshold to conclude that the project's water use consisted of "marginal" quality groundwater, with potentially limited uses. This conclusion should be updated by the interpretation provided by the Water Board Letter, which states the 1,000 mg/L TDS standard should not apply to groundwater. The letter implies that groundwater quality that exceeds 1,000 mg/L TDS should not be treated as categorically degraded.

In fact, in 1988 the Water Board previously determined in Resolution 88-63 that groundwater with TDS concentrations of 3,000 mg/L or less should be protected for and considered as potential supplies for municipal or domestic use unless otherwise designated by one of the Regional Water Quality Control Boards. No such designation has been made for this aquifer so clearly the quality of groundwater the project proposes to use is well below the policy guidance of 3,000 mg/L TDS.

Other sources also agree that water containing in excess of 1,000 mg/L TDS can be suitable for other beneficial uses. The suitability of water for use as irrigation water becomes marginal where TDS concentrations reach 2,000 to 3,000 mg/L. As described by Dr. L.D. Doneen in 1954 (Doneen1954), reiterated by DWR in various Water Quality Investigations, and promulgated in the Water Control Plan for the Tulare Lake Basin (RWQCB2004), water that exceeds electrical conductivity levels of 3,000 micromhos per centimeter and TDS levels of 2,000 mg/L has limited suitability for irrigation use. However, water containing less than 2,000 mg/L is not considered inferior for irrigation

(**Soil & Water Resources Table 3**). Specific studies of crops of pistachios from western San Joaquin Valley indicate no adverse impacts to crop or yield at salinities even greater than 3,000 mg/L TDS (Fergusson2002). These thresholds are relevant to the Palo Verde Valley, where the predominant use for water is irrigated agriculture.

Soil & Water Resources Table 3
Irrigation Water Suitabilities

Irrigation use	Electrical Conductivity (mhos/cm @ 25˚C)	TDS (mg/L)
Suitable/Class I	0 - 1,500	< 700
Marginal/Class II	1,500 - 3,000	700 - 2,000
Inferior/Class III	> 3,000	> 2,000

Source: Doneen1954; Tulare Lake Basin Plan, RWQCB2004

In addition to the laws and policy statements identified above, significant new laws concerning state water policy were passed since the 2005 Commission Decision. Between 2014 and 2015, the Governor signed into law bills that are collectively referred to as the Sustainable Groundwater Management Act (SGMA). Codified as California Water Code Sections 5202, 10540, 10720.1, 10722.4, and 10750 these code sections encourage the establishment of a process by which California's groundwater basins will receive appropriate management and diligent oversight. They also encourage local agencies to work cooperatively to manage groundwater resources within their jurisdictions and to develop Groundwater Sustainability Plans.

Since the licensing of the original project in 2005, California has experienced an unprecedented drought. The Governor proclaimed a State of Emergency January 17, 2014. Executive Orders B-28-14 and No. 29-15 stress the importance of efficient use of water and require various state agencies to help expedite the approval and construction of water conservation projects.

These new laws further stress the importance of reducing unreasonable use of the state's water resources. Staff concludes, just as was concluded in the 2005 staff analysis, that the project should implement dry-cooling in order to comply with the water policy. The SEP would be equally able to meet its objectives while implementing dry-cooling.

Dry Cooling

Staff believes the PTA has not addressed all of the cost differences between the proposed project and a dry-cooled design. In a letter to the Energy Commission's Project Manager dated March 15, 2005, titled Blythe Energy Phase II PSA Dry Cooling Economic Analysis, the applicant concluded that if it were to implement dry cooling, its cost of production would increase between 2.5 and 3.5-percent (BEPII 2005). Since the 2005 Decision, another report was produced for the Energy Commission that shows the cost of implementing wet-cooling relative to dry-cooling. Its conclusion suggests a similar cost difference for combined cycle plants in the desert. Staff believes dry-cooling is even more feasible now with the increasing costs related to water offsets and with other examples around the country of power plants implementing similar dry-cooling systems. The cost for mitigation of 2,800 AFY is expected to be very high, relative to 2005 costs, and the availability of opportunities for real water saving could be limited. The cost of mitigation should be considered when considering the ultimate financial feasibility of the wet-cooled project design.

The 2006 report, *Cost and Value of Water use at Combined-Cycle Power Plants*, compares the economics of wet-cooling versus dry-cooling in the desert, valley, coast, and mountain environments in California. In each of these environments, the cost of dry-cooling was greater than that of wet-cooling. The smallest cost difference was seen in the coast site case, followed by the desert site case. The greatest increase in cost was seen in the valley and mountain cases. The desert case shows an $18 million increased capital cost for the dry-cooled plant versus the wet-cooled one. The annual operating revenue to annual cost comparison also shows the dry-cooled plant is also more expensive per year of operation. The comparison shows a 2.07-percent difference in revenue to cost between the two, or about $3.2 million per year (CEC2006). These findings are similar to those from the 2005 Blythe Energy Phase II PSA Dry Cooling Economic Analysis, which states the cost of energy production from a dry-cooled plant would be 2.5 to 3.5-percent higher than a wet-cooled plant. Though the energy production cost difference is known and may not have changed much since 2005, the current cost of water offsets is expected to be much higher.

Staff obtained draft terms of a fallowing agreement between landowners in Blythe and MWD, from 2004. The agreement provided the landowner with an average of $3,250 per acre of fallowed land that could only be exercised in 10 years out of the 35-year contract. An additional payment of $604 would be paid to the land owners during fallowing years. The Blythe II project was expected to get credit for 4.2 AFY/acre fallowed. Assuming an annual consumption of 2,800 AFY, fallowing of 667 acres would be required. If the project followed terms similar to those of MWD and required land owners to fallow only one-third of the time, the SEP project would need rights to fallowing on 2,000 acres. The cost of 2,000 acres would have been $6,500,000 in 2004. The additional cost of $604 per acre per year fallowed would be an additional $402,868 per year for 667 acres. Over the 30-year project life this cost would be $12,086,040. The total expected cost of mitigation (in 2004) would have been $18,586,040. Staff would expect this cost to be significantly higher today due to a decrease in local farmland supply and increase in demand for land that can be fallowed.

Recent installations of dry-cooling of turbines similar to those proposed by SEP also speak to the feasibility and practicality of this technology in a hot climate where water is scarce. The 2005 Decision states, “Dry cooling, while technologically feasible, is not practically feasible for this project and to meet this project’s objectives.” Staff believes that the dry cooling option is practically feasible for the SEP and should be reevaluated, especially given that SEP is proposing yet again a new combustion turbine. Exelon has broken ground on Wolf Hollow and Colorado Bend generating stations in Texas, using the same turbine technology proposed by SEP (i.e., GE 7HA.02) but both Texas facilities will be dry–cooled. However, Texas is not that dissimilar to California: Texas summers are hot; long term water use and reliability is a concern; and, the Texas electricity market is attempted to integrate rapidly increasing contributions from variable renewable generation. Another installation of an air-cooled GE 7HA.02 was recently permitted in Pennsylvania. Moxie Freedom LLC was issued an air permit approval by the Pennsylvania Department of Environmental Protection on September 1, 2015.

Since the 2005 Commission Decision staff has also gained considerable experience in understanding water offsets available in the Palo Verde area and has also received valuable input regarding the state water policy. Since 2005, the Genesis Solar Energy project, Docket No. 09-AFC-8C, was licensed and built in the neighboring Chuckwalla Valley. This project utilizes dry-cooling and has an annual cap on groundwater use, set at 202 AFY. The Genesis project is currently using water with a TDS content that exceeds 2,000 mg/L. The Genesis project is also involved in a citrus fallowing project on the Palo Verde Mesa that will result in 2,060 acre-feet of savings for the Colorado River. This project speaks to the feasibility of the SEP implementing dry-cooling and also models how an offset program should maintain the water balance in the Colorado River. Compared to the Genesis project, the SEP has the advantage of access to the superior quality groundwater of the Palo Verde Mesa basin.

Additionally, as shown in staff’s WSA below, the Palo Verde Mesa basin has insufficient supplies to meet the needs of the SEP. The implementation of dry-cooling would increase the reliability and sustainability of the SEP operation in the Palo Verde Mesa basin. Water sources in the state are inherently connected and extremely valuable; if reasonably available technology can drastically reduce the consumption of water by the SEP, it should be evaluated for implementation. The potential thermal plume, visual, and noise impacts that could result from adding dry-cooling to the proposed project will discussed in the Air Quality, Visual Resources, and Noise sections, respectively. Staff believes these issues should also be revisited and weighed in consideration of the discussed potential impacts to water resources and compliance with state water policy.

With project use of dry cooling staff would consider elimination of Condition of Certification **SOIL&WATER-9** because there would be a significant reduction in groundwater pumping. The reduction in pumping would not likely result in drawdown impacts to other nearby wells and their users.

Water Conservation Offset Program

A detailed description of the Petitioner’s WCOP has yet to be provided and staff is concerned about the feasibility of their finding a meaningful offset. The petitioner stated that they are in discussions (TN#207177) with PVID about how to line district canals to meet the requirements of the WCOP. Though the petitioner has not provided details about their proposed offset program, staff is concerned that this proposal is unlikely to constitute a true offset. The Rannells Drain is hydraulically connected to the Colorado River through the Palo Verde Valley groundwater basin. Where the canal loses flow to the subsurface, the groundwater system, and ultimately the Colorado River gains additional supply. So lining this canal would result in more flow staying in the canal and being returned to the river, but less flow to the groundwater basin, and net under flow to the Colorado River. This would not result in a decrease in total water consumption in this basin, which is contrary to the intent of the WCOP. As stated above, the Commission expressed its interest that the WCOP be effective and “not just window-dressing on the project.” The Decision also states, “The Commission is concerned that the WCOP actually produces a true offset of the project’s water use.” As discussed above, the cost of water conservation in the Palo Verde area is expected to be very expensive, but it is still a necessary element of the proposed project design.

The amended Blythe Solar Power Project Commission Decision was issued in January 2014, which licensed the project to operate on the Palo Verde Mesa and use water from the same groundwater basin as the proposed project. Though the Blythe Solar Power Project is a photovoltaic design and only needed 40 AFY of groundwater to operate, it was also required to offset the indirect impact it would have on the river.

Although there is no current law requiring a water right for indirect use from the river, staff believes SEP pumping could be subject to future regulation. The need for real water conservation is still driven by the unsustainable use of groundwater in the basin, the need to balance the project’s take from the river, and to make the project consistent with state water policy. If a water conservation program can be identified that would provide the necessary offset, staff may need to revise Condition of Certification **SOIL&WATER–7** to ensure the verification of savings can be demonstrated.

Potable Water Supply

Similar to the original project license the SEP proposes to use groundwater as a potable water supply. Staff recommends the project owner be required to comply with Condition of Certification **SOIL&WATER-5** to ensure groundwater is of adequate quality to protect public health and safety.

COMPLIANCE WITH LORS AND STATE POLICIES

WATER SUPPLY ASSESSMENT

California Water Code, Sections 10910-10915 (Senate Bill 610)

California Water Code, Sections 10910-10915 are intended to inform CEQA decision-makers about project water supplies and their availability. The California Department of Water Resources (DWR) Senate Bill 610 Guidebook provides general guidance about how to interpret Water Code Sections 10910-10915. The central theme of the Guidance is that WSAs are necessary for projects that substantially increase the potable water demand on a local system. The Guidebook discusses how to manage water supplies and how to appropriately project future demands on the water supply system with the next 20 years when considering new developments. Ultimately the WSA should provide evidence that verifies the sufficiency of or the deficiencies in a project’s water supply while ensuring there is an adequate supply for existing users and future demand. The

2005 Decision should be updated to address the requirements of California Water Code Section 19910 through 10915.

Required WSA Elements

Is SEP a "project" under SB 610?

Any CEQA project that meets the Water Code Section 10912 definition of a "project" requires the preparation of a WSA. Section 10912 identifies a "project" as meeting one of the following definitions excerpted from the water code and listed below. Staff bolded the only definitions that could clearly apply to SEP; the other definitions are not tested here and do not require further explanation.

10912. For the purposes of this part, the following terms have the following meanings:

(a) "Project" means any of the following:

(1) A proposed residential development of more than 500 dwelling units.

(2) A proposed shopping center or business establishment employing more than 1,000 persons or having more than 500,000 square feet of floor space.

(3) A proposed commercial office building employing more than 1,000 persons or having more than 250,000 square feet of floor space.

(4) A proposed hotel or motel, or both, having more than 500 rooms.

(5) (A) Except as otherwise provided in subparagraph (B), a proposed industrial, manufacturing, or processing plant, or industrial park planned to house more than 1,000 persons, occupying more than 40 acres of land, or having more than 650,000 square feet of floor area.

(B) A proposed photovoltaic or wind energy generation facility approved on or after the effective date of the amendments made to this section at the 2011-12 Regular Session is not a project if the facility would demand no more than 75 acre-feet of water annually.

(6) A mixed-use project that includes one or more of the projects specified in this subdivision.

(7) A project that would demand an amount of water equivalent to, or greater than, the amount of water required by a 500 dwelling unit project.

(b) If a public water system has fewer than 5,000 service connections, then "project" means any proposed residential, business, commercial, hotel or motel, or industrial development that would account for an increase of 10 percent or more in the number of the public water system's existing service connections, or a mixed-use project that would demand an amount of water equivalent to, or greater than, the amount of water required by residential development that would represent an increase of 10 percent or more in the number of the public water system's existing service connections.

There are two "project" definitions that require further consideration. First is (5) (A), which states,

> *(5)(A) Except as otherwise provided in subparagraph (B), a proposed industrial, manufacturing, or processing plant, or industrial park planned to house more than 1,000 persons, occupying more than 40 acres of land, or having more than 650,000 square feet of floor area.*

This definition would apply to SEP because the project site is 76 acres.

The other project definition that requires additional discussion is item (7), which would require a WSA if a project used an amount of water equivalent to a 500 dwelling unit project.

> *(7) A project that would demand an amount of water equivalent to, or greater than, the amount of water required by a 500 dwelling unit project.*

Guidance for interpreting Water Code Section 10912 is provided in a California Department of Water Resources (DWR) document titled "Guidebook for Implementation of Senate Bill 610 and Senate Bill 221 of 2001 (DWR2003)." A helpful interpretive section on page 3 of the Guidebook, explains how to estimate water consumption for 500 dwelling units. It states that one dwelling unit typically consumes 0.3 to 0.5 AFY (DWR2003). Therefore 500 dwelling units could be interpreted to mean 150 to 250 AFY. The project's use of 2,800 AFY would trigger the requirement to prepare a WSA. If the project's water use were less, the project would still qualify based on its 76 acre footprint.

The SEP is a "project" under SB 610.

Will the project be served by a public water system?

No, SEP would rely on groundwater from the Palo Verde Mesa basin. Since SEP is not served by a public water system, the Energy Commission is responsible for the preparation of the WSA.

Is the project's water use accounted for in a current Urban Water Management Plan (UWMP)?

No, the project would not rely on water from a public water system and its use is not accounted for in a current UWMP.

Will the project rely on groundwater? If so, what is the source?

Yes, the project would rely on 2,800 AFY of groundwater pumped from the Palo Verde Mesa groundwater basin.

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 (CEC2005a).

The Palo Verde Mesa groundwater basin covers approximately 353 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 basin's water bearing zones generally consist of Quaternary sediment that is coarse near the mountains and finer towards the Colorado River (DWR2004).

The groundwater system in the neighboring Palo Verde Valley basin 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 very low (CEC2005a).

The Palo Verde Irrigation District (PVID) is the sole entity in Palo Verde with rights to divert and use Colorado River water. PVID contains approximately 131,298 acres, 26,798 acres of which are on the Palo Verde Mesa. 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 (CEC2005a).

Total recharge for the Pal Verde Mesa basin was estimated by the California Department of Water Resources (DWR) to be about 800 AFY (DWR2004). The Bureau of Land Management (BLM) estimated recharge at 881 AFY (BLM2015). This estimate combined inputs of underflow from the neighboring basins, infiltration of irrigation water that makes it beyond the crop root zone, and infiltration of precipitation that does not runoff or evaporate. **Soil & Water Resources Table 4** summarizes the groundwater budget for the Palo Verde Mesa.

Soil & Water Resources Table 4
Water Budget for the Palo Verde Mesa Groundwater Basin

BUDGET COMPONENTS	PALO VERDE MESA GROUNDWATER BASIN (AFY)
Recharge from runoff infiltration (1%)	242
Underflow from Chuckwalla Valley Groundwater Basin	400
Underflow from McCoy Wash	175
Irrigation Return Flow (1.8% of 3,911 AFY)	72
Total Inflow	889
Groundwater Extraction (wells)	0
Blythe Solar	40
Blythe Energy I	3,000
Sonoran Energy Project	2,800
Total Outflow	5,840
Budget Balance (Inflow-Outflow)	-4,951

Source: Modified from BLM, 2015

Are there sufficient water supplies to serve the project during normal, dry, and multiple dry-year scenarios?

No, as indicated in the budget included as **Soil & Water Resources Table 3** the Palo Verde Mesa basin does not have sufficient storage to meet its current extractions and it would be further over-allocated if the proposed SEP project was permitted to pump groundwater. Though the required assessment to look at dry and multiple dry-years would typically have very little influence on long-term water levels, longer term factors such as prolonged draught could result in gradual water table lowering.

CONCLUSIONS AND RECOMMENDATIONS

The SEP would rely on groundwater and irrigation water that is destined for the Colorado River. Staff is concerned that the projected decrease in Colorado River flows in the future could impact the SEP's reliability. Staff does not believe that an unmetered take from the Colorado River is sustainable, and therefore, reliable. In the recent past, pumpers of Colorado River water were expecting to fall under the Accounting Surface Rule. In the more recent past, many power plants in California have struggled to maintain a drought-proof water supply.

The use of high quality groundwater for cooling is highly discouraged by state water policies both old and new. Since the 2005 Decision, the Governor signed the SGMA laws, which are intended to help better manage groundwater basin balances. The SEP would put the Palo Verde Mesa into even further into an unsustainable condition.

The project owner has not produced a meaningful WCOP to date and staff is concerned that the owner would have great difficulty achieving the necessary offset. The 2005 Commission Decision clearly stated the intent to have the owner provide a meaningful offset program. The 2005 Decision states, "To avoid potential environmental impacts, the WCOP needs to include measures to protect from erosion and to verify true water conservation from qualifying farmlands." Since 2005, farmlands available for water offset have become scarcer in the Palo Verde area; many pieces of land have already been purchased for this purpose by MWD. Staff is also concerned that there may not be enough fallow-able land available on the Palo Verde Mesa to meet the project's needs. The cost to produce a meaningful offset could also be cost prohibitive for the owner. Staff recommends that the WCOP for the SEP follow the leads of the Genesis and Blythe Solar projects by producing a documentable and true offset for the Colorado River.

The staff-prepared WSA indicates that the water supply of the Palo Verde Mesa basin cannot support the SEP. The project also cannot comply with state water policy due to its high water demand and use of high quality water. It is unreasonable to permit such excessive water use when other feasible and economical technologies exist. It is important to note that efforts are being made all along the Colorado River to conserve water resources and augment supplies. Conservation will be necessary to meet the future needs of the river (USBR2012).

Staff recommends that the SEP be modified to incorporate dry-cooling. Though the proposed use of water is not illegal, it is not adequately reliable, and it is not adequately drought-proof. A dry-cooled version of the project would still be expected to be profitable and meet the project's objectives.

PROPOSED CONDITIONS OF CERTIFICATION

The conditions of certification below include the approved conditions of certification from the licensed project and any modifications, additions or deletions required for the amended SEP. (Note: Deleted text is in ~~strikethrough~~, new text is **<u>bold and underlined</u>**).

Some of the proposed conditions below we re-named from "**WATER QUALITY**" and "**WATER RES**" to **SOIL&WATER**" to reflect the current naming convention. Condition of Certification **WATER QUALITY-2** was removed because staff has learned that its purpose is now replaced by **SOIL&WATER-1** and **-2**.

CONSTRUCTION STORM WATER

~~WATER QUALITY-1:~~<u>SOIL&WATER-1:</u> The project owner shall comply with the requirements of the General National Pollutant Discharge Elimination System (NPDES) Permit for Discharges of Storm Water Associated with Construction Activity, if necessary. The project owner shall develop and implement a Storm Water Pollution Prevention Plan for the construction of the entire ~~Blythe Energy Project II (BEP II) project~~ **<u>Sonoran Energy Project (SEP)</u>**(construction SWPPP).

Verification: The project owner shall submit copies to the CPM of all correspondence between the project owner and the RWQCB about the General NPDES permit for the Discharge of Storm Water Associated with Construction Activities within 10 days of its receipt (when the project owner receives correspondence from the RWQCB) or within 10 days of its mailing (when the project owner sends correspondence to the RWQCB). This information shall include copies of the Notice of Intent and Notice of Termination for the project.

~~DRAINAGE, EROSION AND SEDIMENTATION CONTROL PLAN~~

~~WATER QUALITY-2:~~ ~~Prior to site mobilization, the project owner shall obtain CPM approval for a site-specific Drainage, Erosion and Sedimentation Control Plan (DESCP) that ensures protection of water quality and soil resources of the project site and all linear facilities for both the construction and operations phases of the project. This plan shall address appropriate methods and actions, both temporary and permanent, for the protection of water quality and soil resources, demonstrate no increase in off-site flooding potential, meet local requirements, and identify all monitoring and maintenance activities. Monitoring activities shall include routine measurement of the volume of accumulated sediment in the stormwater retention basin. The plan shall be consistent with the grading and drainage plan as required by Condition~~ **~~CIVIL-1~~** ~~and may incorporate by reference any SWPPP developed in conjunction with any NPDES permit. The DESCP shall contain the following elements:~~

~~Vicinity Map~~ ~~– A map shall be provided indicating the location of all project elements with depiction of significant geographic features to include watercourses, washes, irrigation and drainage canals, and sensitive areas.~~

~~Site Delineation~~ ~~– The BEP II site and all project elements shall be delineated showing boundary lines of all construction areas and the location of existing and proposed structures, pipelines, roads, and drainage facilities.~~

~~Watercourses and Critical Areas~~ ~~– The DESCP shall show the location of nearby watercourses including washes, irrigation and drainage canals, and drainage ditches. Indicate the proximity of those features to the BEP II construction site and all pipeline and transmission line construction corridors.~~

~~Drainage~~ ~~– The DESCP shall provide a topographic site map showing existing, interim and proposed drainage systems; drainage area boundaries and water shed sizes in acres; the hydraulic analysis to support the selection of BMPs to divert off-site drainage around or through the site and laydown areas. On the map, spot elevations are required where relatively flat conditions exist. The spot elevations and contours shall be extended off-site for a minimum distance of 100 feet in flat terrain.~~

~~Clearing and Grading~~ ~~– The plan shall provide a delineation of areas to be cleared of vegetation and areas to be preserved. The plan shall provide elevations, slope, location, and extent of all proposed grading as shown by contours, cross sections or other means.~~

~~The locations of any disposal areas, fills, or other special features will also be shown. Illustrate existing and proposed topography tying in proposed contours with existing topography. The DESCP shall include a statement of the quantities of material excavated or filled for each element of the BEP II (project site, transmission corridors, and pipeline corridors), whether such excavations or fill is temporary or permanent, and the amount of such material to be imported or exported.~~

~~***Project Schedule*** – The DESCP shall identify on the topographic site map the location of the site specific BMPs to be employed during each phase of construction (initial grading, project element excavation and construction, and final grading/stabilization). Separate BMP implementation schedules shall be provided for each project element for each phase of construction.~~

~~***Best Management Practices*** – The DESCP shall show the location, timing, and maintenance schedule of all erosion and sediment control BMPs to be used prior to initial grading, during project element excavation and construction, final grading/stabilization, and following construction. BMPs shall include measures designed to control dust and stabilize construction access roads and entrances. The maintenance schedule should include post-construction maintenance of treatment control BMPs applied to disturbed areas following construction.~~

~~***Erosion Control Drawings*** -- The erosion control drawings and narrative must be designed and sealed by a professional engineer/erosion control specialist.~~

~~**Verification:** No later than 60 days prior to start of site mobilization, the project owner shall submit a copy of the plan to Riverside County and the City of Blythe for review and comment, and to the CPM for review and approval. The CPM shall consider comments received from Riverside County and the City of Blythe. During construction, the project owner shall provide an analysis in the monthly compliance report on the effectiveness of the drainage, erosion and sediment control measures and the results of monitoring and maintenance activities.~~

~~Once operational, the project owner shall provide in the annual compliance report information on the results of monitoring and maintenance activities.~~

OPERATIONS STORM WATER

~~**WATER QUALITY-3:**~~ **SOIL&WATER-2:** The project owner shall comply with the requirements of the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity.

The project owner shall develop and implement a Storm Water Pollution Prevention Plan for the operation of the ~~BEP II~~ **SEP** site (operation SWPPP).

Verification: The project owner shall submit copies to the CPM of the operational SWPPP for the entire ~~BEP II~~ **SEP** site prior to commercial operation and all correspondence between the project owner and the RWQCB about the General NPDES permit for Discharge of Storm Water Associated with Industrial Activity within 10 days of its receipt (when the project owner receives correspondence from the RWQCB) or within 10 days of its mailing (when the project owner sends correspondence to the RWQCB). This information shall include a copy of the Notice of Intent and Notice of Termination. A letter from the RWQCB indicating no General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity is required will satisfy this condition.

SEPTIC SYSTEM

~~WATER QUALITY-4:~~ SOIL&WATER-3: The on-site septic system shall be designed and operated to comply with County and City standards and prevent any adverse impacts to water quality. Prior to the start of commercial operation and/or discharge of waste to the septic system, the project owner shall provide the CPM with documentation from Riverside County and the City of Blythe confirming that the septic system design and operational plan is consistent with County and City standards. Waste shall not be discharged to the septic system until the documentation confirming that the system design and operating plan are consistent with County and City standards has been reviewed and approved by the CPM.

Verification: No later than sixty days prior to start of commercial operation and/or discharge of waste to the septic system the project owner shall submit the required documentation from the County and City to the CPM for review and approval.

ZERO LIQUID DISCHARGE SYSTEM

~~WATER QUALITY-5:~~ SOIL&WATER-4: The project shall operate with a Zero Liquid Discharge (ZLD) wastewater treatment system. A liquid wastewater discharge either on or off-site is prohibited, with the exception of the temporary discharge of wastewater to evaporation ponds permitted by the RWQCB via the issuance of Waste Discharge Requirements during periods of ZLD system outages. The design shall include a schematic, narrative of operation, maintenance schedules, on-site salt cake or slurry storage facilities, containment measures and influent water quality. The design information shall also include characterization of the residual cake solid or slurry waste to be produced by the ZLD system that adequately describes the physical and chemical properties for consideration of appropriate storage, transportation, and disposal. The project owner shall provide annual reporting of the functionality of the ZLD system and document any problems to the CPM.

Verification: Sixty (60) days prior to the start of construction of the Zero Liquid Discharge (ZLD) system, the project owner shall submit to the CPM the final design of the system for approval. In the annual compliance report, the project owner shall submit a status report on operation of the ZLD system, including disruptions, maintenance, volumes of interim wastewater streams stored on site, volumes of residual cake solids or slurry generated and the landfills used for disposal.

GROUNDWATER TESTING

~~**WATER QUALITY-6:**~~ **SOIL&WATER-5:** The Applicant shall conduct an annual water quality sampling and analysis of groundwater from any one of the operational wells constructed to supply the project with groundwater and report the results of the analysis to the CPM. The report shall include a summary table that, at a minimum, lists for each of the constituents analyzed, the name of the constituent, the unit of measurement, the method, the applicable standard, the detection level, the sample results, the date sampled and the date analyzed. The report shall also include copies of the original laboratory reports.

Water quality sampling shall include the analysis of the following constituents: (See table). Appropriate sampling and analytical quality assurance and quality control documentation from the laboratory of choice shall be included with the analytical results.

The results of the required groundwater analyses shall be provided to the CPM and the Colorado River Basin Regional Water Quality Control Board, including a summary and a complete copy of the analytical laboratory reports, on an annual basis beginning after one year of operation on the anniversary date the ~~BEP II~~ **SEP** begins operation and continuing for a total of 5-years. If no annual analyses during the first five years of the project indicate that the concentration of any contaminant found in groundwater is above its ESL, the need for continued monitoring shall be reassessed at the end of the 5-year period, and the monitoring program shall be modified as appropriate by the CPM.

If any annual analysis indicates that the concentration of any contaminant found in groundwater is above its Environmental Screening Level (ESL as determined by the San Francisco Bay Regional Water Quality Control Board), the project owner shall be required to develop a mitigation workplan for one of the mitigation options. The workplan shall be submitted to the Colorado River Basin Regional Water Quality Control Board for review and comment and to the CPM for review and approval. Based on discussions between the CPM, the project owner, and the Colorado River Basin Regional Water Quality Control Board, the CPM will direct the project owner to prepare:

a. A human health risk assessment, using methodology reviewed by the Colorado River Basin Regional Water Quality Control Board and approved by the CPM, demonstrating that the increased level(s) of groundwater contaminant(s) pose an insignificant risk to on-site workers and the off-site public, or

b. A pre-treatment plan for groundwater to reduce the contaminant levels to below the applicable ESL.

If the risk assessment is approved by the CPM, groundwater shall continue to be used for the project and the workplan shall provide for annual groundwater sampling, additional risk assessment as required by the CPM, and reporting for the life of the project to demonstrate that the level(s) of groundwater contaminant(s) continue to pose an insignificant risk to onsite workers and the off-site public. However, if subsequent risk assessments indicate a significant risk to on-site workers or the off-site public, a new mitigation workplan shall be required and the project owner shall be required to implement a pre-treatment plan for groundwater.

If a pre-treatment plan is selected and treated groundwater is used for the project, the workplan shall include quarterly sampling, analysis, and reporting to verify that groundwater treatment is effective and all constituent concentrations of the project water supply remain below the applicable ESL. Should the initial treatment method be determined ineffective at maintaining contaminant levels below the applicable ESL, a new workplan shall be required and the project owner shall be required to implement modify the water treatment method. If no treatment method is capable of maintaining contaminant levels below the applicable ESL, the CPM shall report the matter to the Commission.

Verification: If any annual analysis indicates that the concentration of any contaminant found in groundwater is above its ESL, the required mitigation workplan shall be submitted to the CPM for review and approval with 90 days of the submittal of the annual water quality sampling and analysis report.

EVAPORATION POND PERMITTING

~~WATER QUALITY-7:~~ SOIL&WATER-6: The project owner shall comply with all of the requirements of the RWQCB to discharge wastewater to the project's evaporation ponds. The project owner shall follow RWQCB Waste Discharge Requirements (WDRs) for these ponds, and shall not discharge any waste to the evaporation ponds without final WDRs in place. The project owner shall report to the CPM any notice of violation, cease and desist order, cleanup and abatement order, or other enforcement action taken by the RWQCB related to the WDRs.

The project owner shall describe all actions taken to correct violations and operate the project in compliance with WDRs permit conditions. The project owner shall provide confirmation from the RWCQB that any violations have been resolved to the satisfaction of the RWQCB.

Verification: Final RWQCB WDRs must be received by the CPM prior to start of commercial operation and/or discharge of waste to the ponds. The project owner shall report violations and the final resolution of the violation within 10 days of notice by the RWQCB.

WATER CONSERVATION OFFSET PLAN

~~WATER RES-1:~~ SOIL&WATER-7: No later than 6 months after the beginning of site mobilization, the project owner shall provide a Water Conservation Offset Plan (WCOP) for review and comment by the Natural Resources Conservation Service (NRCS), US Bureau of Reclamation (USBR), Colorado River Board (CRB), and the Palo Verde Irrigation District (PVID), and for review and approval by the CPM. The CPM-approved WCOP shall remain in effect for the life of the project, unless superseded by a USBR-approved WCOP following assertion of federal jurisdiction over project groundwater pumping. The Final WCOP shall include the following:

a) Best Management Practices (BMPs) to prevent significant impacts resulting from soil erosion of the fallowed lands for all soil types.

b) Tabulation and corresponding maps of lands and the acreages proposed for fallowing and documentation to verify that they have been irrigated during at least 3 of the 5 most recent years.

c) An estimate of the water required and the methods planned to measure water use as needed to prevent soil erosion of fallowed agricultural lands, i.e., water used by a cover crop, etc., and the proposed means to include such use in the accounting method of actual water conserved.

d) Demonstration in the water conservation accounting method that ~~BEP II~~ **SEP** will not be credited with other independent water conservation activities occurring within PVID's service area for which the WCOP has no effect.

e) Methodology for annual monitoring of the results of the WCOP demonstrating actual water conservation equivalent to ~~BEP II~~ **SEP's** proposed annual water use of up to ~~3,300~~ **280** acre-feet per year.

Verification: No later than 6 months after the beginning of site mobilization, the project owner shall submit a WCOP to NRCS, USBR, CRB and PVID for review and comment, and to the CPM for review and approval. In the annual compliance report, the project owner shall submit its annual accounting under the WCOP demonstrating the actual conservation of Colorado River water equivalent to ~~BEP II~~ **SEP's** annual water use, and that erosion impacts from fallowed/retired land remain less than significant.

GROUNDWATER METERING

~~WATER RES-2:~~ SOIL&WATER-8: The project owner shall install metering devices to record the daily amount of groundwater withdrawn by ~~BEP II~~ **SEP**, separate and distinct from water use metered and reported by the BEP I project. The project owner shall prepare an annual water use summary coordinated with the annual compliance report for each well, which shall include:

- total water withdrawn by the project on a daily basis in gallons, and
- total water withdrawn by the project on an annual basis in acre-feet.

Following the first year, the annual water use summary shall also include:

- yearly range of water withdrawn for each well by the project and
- yearly average of water withdrawn for each well by the project.

Verification: As part of its annual compliance report, the project owner shall submit annual groundwater use data for each well as part of its annual water use summary to the CPM, the Palo Verde Irrigation District, and the United States Bureau of Reclamation for the life of the project.

WELL INTERFERENCE MITIGATION

~~**WATER RES-3:**~~ **SOIL&WATER-9:** The project owner shall pay or reimburse all wells owners (at the affected well owner's option) whose wells are located on the Palo Verde Mesa, 3 miles or less from the midpoint of the ~~BEP II~~ **SEP** - BEP I well field for a predicted cumulative decline in static groundwater level of 5 feet or more.

The project owner shall pay or reimburse the well owner an amount equal to the customary local cost of lowering the well owner's pump setting necessary to accommodate the decline in water level caused by the project, unless the project owner can demonstrate to the satisfaction of the CPM that the existing pump setting is sufficiently deep that lowering is unnecessary. In the event that the pump setting cannot be lowered without deepening the well, the project owner shall pay or reimburse the well owner an amount equal to the customary local cost of deepening the well. If the well cannot be deepened, the project owner shall pay or reimburse the well owner an amount equal to the customary local cost of installation of a new well.

The project owner shall provide evidence of notification describing the ~~BEP II~~ **SEP** well interference mitigation requirements to all Palo Verde Mesa property owners whose land is located 3 miles or less from the midpoint of the ~~BEP II~~ **SEP** - BEP I well field.

Verification: At least 90 days prior to well construction, the project owner shall provide evidence to the CPM that it has notified all Palo Verde Mesa property owners, whose land is located 3 miles or less from the midpoint of the ~~BEP II~~ **SEP** – BEP I well field, regarding the ~~BEP II~~ **SEP** well interference mitigation requirements. The project owner shall submit an annual compliance report describing compensation for pump lowering, pump replacement, or well deepening as well as any other well modifications undertaken to comply with the provisions of this condition to the CPM for review and approval.

ANNUAL WATER USE LIMIT

~~**WATER RES-4**~~ **SOIL&WATER-10:** ~~BEP II~~ **SEP's** annual use of water shall not exceed a maximum of ~~**2,800**~~ **280** acre-feet per year.

Verification: In compliance with ~~**WATER RES-2**~~ **SOIL&WATER-8**, the project owner shall record and provide to the CPM water use reports that demonstrate annual water consumption does not exceed ~~**2,800**~~ **280** AFY.

WATER METERS

~~**WATER RES-5**~~ **SOIL&WATER-11:** The project owner shall service, test and calibrate the water meters in accordance with the manufacturer's specifications.

Verification: When the metering devices are serviced, tested and calibrated, the project owner shall provide to the CPM a report summarizing these activities in the next Annual Compliance Report (ACR).

FIRST YEAR WATER USE REPORTING

~~**WATER RES-6**~~ **SOIL&WATER-12:** For the first year of operation the project owner shall monitor, record, and submit to the CPM the total water used on a monthly basis.

Verification: On a monthly basis for the first year of operation, the project owner shall provide to the CPM a Monthly Water Use Summary that states the quantity of water used daily during that month.

ANNUAL WATER USE REPORTING

~~**WATER RES-7**~~ **SOIL&WATER-13:** The project owner shall prepare an annual Water Use Summary, which will include the monthly range and monthly average of water usage in gallons per day, and total water used by the project on a monthly and annual basis in acre-feet. For calculating the annual water use, the term "year" will correspond to the date established for the Annual Compliance Report (ACR) submittal.

For years subsequent to the first year, the annual Water Use Summary shall in addition to the information described above, also include the yearly range and yearly average water use by the project. The annual Water Use Summary shall be submitted to the CPM as part of the ACR.

Verification: The project owner shall provide a Water Use Summary that sets forth the information required in the condition above in the ACR. All prior annual water use, including yearly range and yearly average, shall be reported in subsequent ACRs.

REFERENCES

ASE2015a - AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

BLM2015 – Final Environmental Impact Report, Blythe Mesa Solar, March 2015.

BEPII2005 – Supplemental Response to California Energy Commission Preliminary Staff Assessment, Blythe Energy Project Phase II PSA Dry Cooling Economic Analysis, Caithness Blythe II LLC, March 15, 2005.

CEC2005a – California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2005b – California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

CEC2006 – Cost and Value of Water Use at Combined-Cycle Power Plants, CEC-500-2006-034. Prepared for the California Energy Commission, April 2006.

Doneen1954 – Salinization of soil by salts in the irrigation water. Trans. Am. Geophysics. Union, 53: 943-950.

DWR2003 – California Department of Water Resources. Guidebook for Implementation of Senate Bill 610 and Senate Bill 221 of 2001 to assist water suppliers, cities, and counties in integrating water and land use planning. October 8, 2003.

DWR2004 – California's Groundwater Bulletin 118, Hydrologic Region Colorado River, Palo Verde Mesa Groundwater Basin. Department of Water Resources. Updated February 27, 2004.

FedReg2008 – Federal Register, Part II, Department of the Interior, Bureau of Reclamation, 43 CFR Part 415: Regulating the Use of Colorado River Water Without an Entitlement; Proposed Rule. July 16, 2008.

Ferguson2002 – Pistachio rootstocks influence scion growth and ion relations under salinity and boron stress. Journal of the American Society For Horticultural Science, 127(2), 194-199.

Genesis2010 – Reply Brief of Commission Staff in Response to Committee Order Granting Genesis Solar, LLC Motion for Scoping Order, Hearing, and Order Scheduling Time for Filing Briefs. Posted January 25, 2010.

RWQCB2004 – Water Quality Control Plan for the Tulare Lake Basin, Second Edition, Central Valley Regionally Water Quality Control Board. January 2004.

USBR 2012 – United States Bureau of Reclamation, Colorado River Basin Water Supply and Demand Study, Technical Report B – Water Supply Assessment. December 2012.

SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
TRAFFIC & TRANSPORTATION
Michael C. Baron and James Adams

SUMMARY OF CONCLUSIONS

Staff concludes that the Petition to Amend (PTA) to the Blythe Energy Project Phase II (BEP II), named the Sonoran Energy Project (SEP), would require additional analysis and supplementation of the BEP II 2005 California Energy Commission (Energy Commission) Decision (2005 Decision) in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162. The SEP would create new, potentially significant direct and cumulative traffic and transportation impacts and would not comply with applicable laws, ordinances, regulations, and standards (LORS). The proposed use of evaporation ponds is inconsistent with the provisions of the Riverside County Airport Land Use Compatibility Plan (RCALUCP), which prohibits land use development in compatibility zones “C” and “D” of the Blythe Airport that may increase the attraction of birds. The potential for evaporation ponds to attract birds, which could collide with airplanes using the Blythe Airport, was an issue addressed in the 2005 Decision but resolved by the original project applicant modifying the BEP II by substituting evaporation ponds for a zero liquid discharge (ZLD) system.

In addition, the 2005 Decision includes Condition of Certification **TRANS-9**, which specifies that project construction cannot start until the measures specified in the condition to mitigate aviation safety impacts from thermal plumes are accomplished. The PTA proposes to modify **TRANS-9** in a way that the project owner will have satisfied the condition by merely “requesting” that the Federal Aviation Administration (FAA) implement the measures. No alternative mitigation measures are proposed in the event the FAA does not agree to implement the measures in **TRANS-9**, despite the project owner’s thermal plume modeling results which predict higher velocity plumes from the SEP compared to the BEP II. Staff is proposing the SEP use dry cooling instead of a wet cooling tower for the SEP. Dry cooling would emit invisible thermal plumes rather than visible water vapor. A preliminary analysis for dry cooling was conducted by staff that shows a significant increase in plume velocity as compared to a wet cooling tower.

INTRODUCTION

Staff reviewed the 2005 Decision and analyzed the proposed changes to the licensed BEP II, which include replacing the previously approved combustion and steam turbines with different turbines, using evaporation ponds rather than ZLD for wastewater discharges, relocating the transmission line (gen-tie), increasing the size of the auxiliary boiler, and decreasing the size of the cooling tower. The PTA also requests that the BEP II name be changed to the Sonoran Energy Project.

The original licensing proceedings for the BEP II used traffic counts from the Blythe General Plan Circulation Element adopted in 1989. Since that time, the city of Blythe adopted a new general plan circulation element in March 2007 that was developed using data from the Palo Verde Valley Transportation Master Plan (PVVTP) adopted in December 2000 (PVVTA 2015a). Staff used the traffic data pertinent to the SEP from the 2007 Blythe General Plan Circulation Element as a baseline for evaluating the amended SEP.

In accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that supplementation to the 2005 Decision is necessary for Traffic and Transportation because of the updated traffic counts, the project owner's proposal to use evaporation ponds rather than a ZLD system, and the amended project's higher velocity thermal plumes.

SUMMARY OF DECISIONS

BEP II 2005 FINAL DECISION

The BEP II was licensed in 2005. The traffic analysis addressed the impacts associated with the transportation system in the local area, the identification of roads and routing proposed to be used for construction and operation; probable routes associated with the delivery of hazardous materials; and the effects of thermal plumes that could adversely affect flight operations at the Blythe Airport, particularly student pilots. The 2005 Decision found the proposed project in conformance with the applicable laws related to traffic and transportation and determined that all potential adverse traffic impacts will be mitigated to less than significant with implementation of the following conditions of certification:

- **TRANS-1:** Compliance with vehicle size and weight limits on roadways and highways;
- **TRANS-2:** Compliance with Caltrans and local jurisdiction encroachment permit requirements;
- **TRANS-3:** Compliance with hazardous material transportation permit and license requirements;
- **TRANS-4:** Implementation of a parking plan;
- **TRANS-5:** Implementation of a traffic control plan;
- **TRANS-6:** Securing a private vehicular access easement for a secondary vehicle access road;
- **TRANS-7:** Repairing roadways damaged during construction;
- **TRANS-8:** Installing lighting fixtures identical to those installed at Blythe Energy Project pursuant to the city of Blythe's requirements and consistent with FAA requirements (FAA Advisory Circular 70/7460-1J; and

- **TRANS-9:** Documenting that the following actions for the Blythe Airport have been completed prior to beginning project construction:
    - o Adding a remark on the Automated Surface Observation System advising pilots to avoid low-altitude direct overflight of the BEP II;
    - o Changing the Visual Flight Rule traffic pattern for Runway 26 from left-hand turns to right-hand turns; and
    - o Designating a runway other than Runway 26 as the primary calm wind runway.

2012 BEP II DECISION

The changes proposed to the licensed BEP II in the 2009 PTA, and approved by the Commission in 2012, were found to have no new or substantially more severe traffic and transportation impacts. The conditions of certification in the 2005 BEP II were determined to be sufficient to mitigate the modified project's significant effects on traffic and transportation and ensure continued compliance with applicable LORS. A supplemental filing to the 2009 PTA included a minor proposed change to the verification portion of Condition of Certification **TRANS-9**. The proposed change, which would not have modified any substantive requirement in the condition, was not carried forward by staff in its analysis of the PTA and was not included in the 2012 Commission Order (2012 Order) approving the 2009 PTA. The version of **TRANS-9** included in this Preliminary Staff Assessment (PSA) is from the 2005 BEP II Decision.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS) COMPLIANCE

While the proposed amendment would not trigger new LORS that may not have been applicable to the original project, there have been updates to local LORS. The city of Blythe's current General Plan Circulation Element adopted in 2007, uses traffic count data from the PVVTP adopted in 2000. The licensed BEP II used traffic data from the Blythe General Plan Circulation Element adopted in 1989. Another LORS change since the 2005 Decision is the updated Blythe chapter of the RCALUCP, which was adopted in October 2004 (COB 2007). The 2005 Decision considered the policies in an earlier version of the plan called the Blythe Airport Comprehensive Land Use Plan, dated August 1992 (CEC 2005a). The project as proposed would not comply with the RCALUCP for two reasons. First, evaporation ponds attract birds and are prohibited in airport influence zones. Second, if **TRANS-9** is infeasible, and no alternative mitigation measures are identified, thermal plumes could cause unmitigable hazards to aircraft. These issues are discussed further below in the "Environmental Impact Analysis" subsection.

ENVIRONMENTAL IMPACT ANALYSIS

The 76-acre SEP site is located within the city of Blythe in the Palo Verde Valley region of Southeastern California. Surrounding land uses include the Blythe Airport one mile east of the site, the existing Blythe Energy Project (BEP) adjacent to the west, vacant industrial land to the north, and Interstate 10 (I-10) to the south. **Traffic and Transportation Figures 1** and **2** illustrate important aspects of the regional and local transportation system. The site is readily accessible via the I-10 freeway along Hobsonway serving as a frontage road to the south and Buck Boulevard to the west. Other regional and local roadways serving the site include State Route (SR) 78 (Neighbours Boulevard) and United States Highway 95 (U.S. 95, Intake Boulevard). The total duration of construction of the SEP would be 26 months, compared to 18 to 20 months for the BEP II. Construction would typically take place between the hours of 8:00 am and 4:30 pm, Monday through Friday.

IMPACTS TO ROADWAYS

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. As indicated earlier, the city of Blythe 2007 General Plan Circulation Element was used to obtain baseline traffic counts on roadways and intersections near the project site. Baseline traffic levels in the area are similar to the conditions considered in the BEP II proceeding. **Traffic and Transportation Table 1** summarizes the most recently available data characteristics of the roadway segments studied for the SEP. Primary access to the SEP site will be provided via the north entrance off Riverside Avenue. The existing BEP entrance would be connected to the SEP entrance via a new access road. A secondary SEP access road would be from Hobsonway. The level of service (LOS) for all affected local roadway segments during the peak hour is LOS A (free flowing) as shown in **Traffic and Transportation Table 1**

TRAFFIC AND TRANSPORTATION Table 1
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 U.S. 95	A
U.S. 95 between Hobsonway and I-10	A
U.S. 95 at I-10	A
U.S. 95 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: Adapted from 2007 City of Blythe General Plan Circulation Element

As shown in **Table 2**, all highways in the area currently operate at LOS A. Staff's October 28, 2015 observations of the Blythe area's highway and road network and related traffic levels indicate that LOS A conditions still exist within the vicinity of the project site.

Traffic and Transportation Table 2
2014 Existing Highway Conditions

Highway		Annual Average Daily Traffic[1]	Maximum Two-Way Traffic Volume	Volume to Capacity (V/C)[3]	LOS
I-10	Between Wiley's Well Road and Mesa Drive	23,500	61,200	0.38	A
	Between Mesa Dive and SR-78	23,000	61,200	0.38	A
	Between SR-78 and Lovekin Blvd	25,000	61,200	0.41	A
SR-78	Between Ripley/Broadway Street and I-10	2,800	10,400	0.27	A
	Between I-10 and Hobsonway	2,800	10,400	0.27	A

Source: Petition to Amend Table 3.11-1, Caltrans, Traffic Data Branch, 2014

During an average construction month, the amended SEP would require an average construction workforce of approximately 82 workers making 163 daily trips. During peak construction, which would occur during month 12, 325 workers would commute to the site, making 650 daily trips. The SEP would have essentially the same peak construction workforce than the assumed 387 peak workers for the licensed BEP II.

The licensed BEP II assumed 150 passenger car equivalent (PCE) truck trips would be required during peak construction activities whereas the amended SEP would require 160 PCE truck trips during peak construction activities. **Traffic and Transportation Table 3** summarizes the construction project trip generation studied for the SEP. The construction traffic associated with SEP would be comparable to the licensed BEP II.

Traffic and Transportation Table 3
Project Construction Trip Generation

Trip Type	Daily Trips (Peak Construction)	Daily Trips (Average)	AM Peak Hour			PM Peak Hour		
			In	Out	Total	In	Out	Total
Delivery Trucks	69	48	41	41	82	28	28	56
Hauling Trucks	100	25	25	25	50	25	25	50
PCE (1.5)	254	110	99	99	198	80	80	160
Workforce	650	163	325	0	325	0	325	325
Total Construction Traffic in PCE	904	273	424	99	523	80	405	485

Notes: Construction schedule and personnel power loading provided by project owner. Construction activity assumed to occur 10 hours per day; 6 days per week; 23 days per month. All worker and delivery truck travel assumed to travel to the project site.
PCE = passenger car equivalent
Source: ASE 2015a - SEP Petition to Amend Table 3.11-2, pg. 3-138.

In the 2005 Decision, the Energy Commission concluded that because roadways operate at LOS A, the construction traffic would not cause significant traffic congestion impacts. For SEP, staff concludes that the intersections and roadways in the vicinity of the site will continue to operating at acceptable LOS (LOS A) and no significant impacts would occur. The Energy Commission required a number of conditions of certification (**TRANS-1** through **TRANS-7** identified earlier in this analysis) to ensure the project's traffic and transportation impacts would be less than significant as they relate to public safety, emergency access, parking, and alternative transportation. These issues are unchanged, and staff concludes that no supplementation is necessary, and the Committee can rely on the analysis of these issues in the 2005 Decision.

AIRPORTS

The eastern end of Runway (RY) 8-26 at the Blythe Airport is located approximately 4,500 feet due west of the SEP site. Similar conditions would apply to the SEP that was analyzed for the licensed BEP II. Arrival and departure air traffic using RY 8-26 could fly over the proposed project given the traffic pattern altitude of 800 feet above ground level (AGL) for the downwind leg and 300 feet AGL for final approach. Planning for the area surrounding the Blythe Airport is dictated by the Riverside County Airport Land Use Commission (RCALUC). The RCALUCP defines airport influence area as an area where future airport-related noise, overflight, safety, or airspace protection factors may significantly affect land uses or necessitate restrictions on those uses. The RCALUCP identifies that new land uses that may cause visual, electronic, or increased bird strike hazards to aircraft in flight shall not be permitted within any airport's influence area. Like the BEP II, the SEP would be located in RCALUCP compatibility zones "C" and "D". Most of SEP's new development occurs within compatibility zone "D". Only the gen-tie infrastructure and access road are located within compatibility zone "C".

As described throughout the Project Description section of the PTA, the SEP would use evaporation ponds for wastewater disposal rather than processing wastewater in a ZLD system like the licensed BEP II. Evaporation ponds are known to attract birds – the 2005 Decision reports documented use by birds of the existing BEP ponds (CEC2005b, page 58). Potential impacts to aircraft from increased bird strike hazards were minimized for the BEP II by the original applicant's agreement to modify the project to use a ZLD system for wastewater disposal and limited use of evaporation ponds. The SEP's proposed use of evaporation ponds as the sole mechanism to dispose of wastewater would be inconsistent with the RCALUCP prohibition on land uses that can increase bird strike hazards, and would cause new potentially significant impacts. Birds can be sucked into aircraft engines or air intakes of small aircraft and can cause engine malfunction or failure resulting in loss of power and control of the aircraft. The project owner has not proposed any mitigation to avoid this impact.

The RCALUCP does not include thermal plumes in the list of hazards to flight, although as discussed extensively in the 2005 Decision, thermal plumes can be hazardous to aircraft. Similar to the licensed BEP II, the SEP's gas turbine and cooling tower would emit thermal plumes that could result in turbulence with the potential to affect aircraft maneuverability above the SEP site. Water staff is proposing the SEP use dry cooling instead of wet cooling. Under this scenario, an air cooled condenser (ACC) would replace the wet cooling tower. While the ACC would emit thermal plumes, it would not emit visible water vapor plumes. An air-cooled condenser would be approximately 130 feet high, 347 feet long and 181 feet wide. More accurate dimensions will be provided in the Final Staff Assessment (FSA). A preliminary analysis by staff shows the ACC critical plume velocity of 4.3 meters per second (m/s) is predicted to occur up to 1,500 feet AGL.

For BEP II, the Energy Commission found that aircraft encountering the project's thermal plumes can be adversely affected, noting in particular that the BEP II's thermal plumes could significantly upset flight in the left-hand pattern of RY 26 at altitudes noted above (CEC2005b, pages 180 and 184). Staff's plume modeling conducted for BEP II estimated that plumes from the cooling tower and turbines with sufficient velocity to cause turbulence (4.3 m/s) would easily exceed 500 feet above the ground. For SEP, the project owner has estimated under worst-case conditions that the thermal plumes emitted from the gas turbine and the cooling tower will exceed the critical velocity of 4.3 m/s at elevations up to 800 feet and 1,088 feet above the ground, respectively (ASE2015a, page 3-139). Staff will be conducting its own plume velocity analysis for the project as proposed and for the staff proposal to require use of an air cooled condenser. This analysis will be included in the FSA, which will include staff's proposed air cooled condenser, and incorporate the results in the FSA for the SEP.

To mitigate potential flight risks from the project's thermal plumes, the Energy Commission adopted Condition of Certification **TRANS-9**, which incorporated agreements reached between Blythe Airport stakeholders and the original project applicant. As specified by **TRANS- 9**, the project owner shall not commence construction of the BEP II until the following are accomplished:

1. A remark is placed on the Airport's Automated Surface Observation System (ASOS), or equivalent broadcast, advising pilots to avoid low-altitude direct overflight of the power plant;
2. The Visual Flight Rules (VFR) traffic pattern to RY 26 is changed from left-hand turns to right-hand turns; and
3. A runway, other than RY 26, is designated as the primary calm wind runway.

On October 28, 2015, Energy Commission staff met with RCALUC staff and the Blythe Airport manager (County of Riverside Economic Development Agency [EDA]) to discuss the current SEP. EDA staff confirmed that the Instrument Landing Approach for RY 26 has been disconnected, however they believe the FAA would oppose implementation of measure #2 (changing the traffic pattern for RY 8/26 from left-hand to right-hand turns) and measure #3 (designating a runway other than RY 8/26 as a calm wind runway) in **TRANS-9**. The PTA proposes to modify **TRANS-9** in a way that the project owner will have satisfied the condition by merely "requesting" that the FAA implement the measures. The 2005 Decision acknowledges that the measures agreed to by the original applicant require FAA approval, and states that "the Commission shall retain jurisdiction to impose or, as appropriate, seek the FAA's imposition of alternate or additional measures if circumstances warrant" (CEC2005b, page 190).

The project owner has not demonstrated that the SEP's thermal plumes would not have potentially significant impacts on aircraft operations or offered any alternative mitigation measures in the event the FAA does not agree to implement measures #2 and #3. Staff is planning a meeting with RCALUC and EDA staff and the FAA to discuss implementation of **TRANS-9**.

The FAA is required to be notified prior to the construction of structures potentially affecting navigable airspace. The proponent of any construction or alteration within 20,000 lineal feet of a public use or military airport which exceeds a 100:1 vertical surface from any point on the runway of an airport, with at least one runway more than 3,200 feet long, must file Form 7460-1 (Notice of Construction/Alteration of Navigable Airspace) with the FAA to determine if the structure or alteration would cause an aviation hazard (FAA 2010). The east edge of the primary airport runway (Runway 8-26) is approximately 4,500 feet west of the SEP site and is located at 393 feet above mean sea level (MSL). The SEP site is approximately 338 feet above MSL. The navigable airspace for Blythe Airport above the SEP site begins at 100 feet (45 feet {4,500 divided by 100} plus the 55 foot difference between the RY 26's elevation and the elevation at the SEP site). The SEP's heat recovery steam generator (HRSG) stack would be 140 feet high, the maximum height of the project. Given the proximity of the Blythe Airport to the project site and runway 8-26, any structure over 100 feet tall would penetrate the Blythe Airport's navigable airspace and require FAA review. In addition to the 140-foot tall HRSG stack, the poles supporting the gen-tie could be as tall as 110 feet (ASE 2015a, Appendix 3.1 F). Although not stated in the PTA, a construction crane in excess of 100 feet would most likely be used to construct the HRSG and other project structures. The project owner filed a 7460-1 form for the SEP's HRSG stack with the FAA and received a determination of no hazard to air navigation. The FAA will not require marking and lighting for the exhaust stack, but recommends following the standards established in Advisory Circular 70/7460-1J if the project owner elects to mark and light the stack. The project owner is required by **TRANS-8** to 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). FAA's no hazard determination will expire in January 2017 if construction has not commenced by then.

CUMULATIVE IMPACTS

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 impacts taking place over a period of time.

The amended SEP would be most likely to combine with other nearby projects to result in cumulative traffic impacts during the construction phases, which would generate much more traffic than the operations phase, when minimal traffic would be generated. Because of this, staff evaluated cumulative traffic impacts for the construction time period of the amended SEP and other projects in the vicinity. Staff also analyzed the potential for cumulative aviation impacts as discussed below. Based on all current information available at this time; the following information outlines the status of major projects within the licensed BEP II area that could combine with the amended SEP to produce traffic and transportation cumulative impacts. Staff has considered the following five projects that are located within close proximity of the SEP:

1. Blythe Mesa Solar Power Project is a 485 MW solar photovoltaic (PV) facility and 8.4-mile generation interconnection line on 3,660 acres. The project is located 0.84 miles southwest of the SEP on property located both north and south of I-10. The project was approved by the Bureau of Land Management on August 15, 2015;
2. NRG Blythe II Energy Project is a 20 MW solar PV facility located 2.13 miles northwest of the SEP. The project was approved by Riverside County Transportation and Land Management Agency and is currently under construction;
3. Palo Verde Energy Project is a 486 MW solar PV facility located 2.34 miles north of the SEP. The project is currently under review by the Riverside County Transportation and Land Management Agency;
4. NextEra Blythe Solar Power Project (Docket No. 09-AFC-6C) is a 485 MW solar PV facility on 4,070 acres. The project is located 4.7 miles northwest of the SEP. The project was approved by the Energy Commission on January, 15, 2014 and is currently under construction; and
5. NextEra McCoy Solar Energy Center, LLC is a 750 MW photovoltaic PV facility on 8,170 acres. The project is located 7.5 miles northwest of the SEP. The project was approved by the Bureau of Land Management on March 13, 2013 and is currently under construction.

The traffic and transportation mitigation required for projects reviewed under federal jurisdiction mirrors the required mitigation for the BEP II. It is assumed that all future cumulative projects would include mitigation similar to that for licensed BEP II (i.e. parking and staging areas, development of a construction traffic control plan, size and weight limits, permits for hazardous materials transport, and encroachment permits) and would require approval from the city of Blythe or Caltrans, as well as other affected jurisdictions and agencies. The incremental effect of the SEP could be cumulatively considerable when combined with the effects of past, present and reasonably foreseeable projects within proximity (approximately 8 miles) of the SEP. With the incorporation of the mitigation measures previously mentioned above, the SEP's contribution to cumulative effects of past, present and reasonably foreseeable projects would be mitigated to a less than significant level and therefore would not be cumulatively considerable.

On December 14, 2015, Energy Commission staff received confirmation from Ed Cooper, Director RCALUC, via e-mail that the cumulative projects list prepared by Energy Commission staff appeared to be complete. All of the projects within approximately 8 miles of the SEP are associated with solar PV projects. Solar PV projects do not generate thermal plumes, do not include evaporation ponds, use matte or non-reflective surfaces for support structures, and use non-reflective coating on PV panels. Therefore, these 5 solar projects would not combine with the SEP to have cumulative impacts on aviation safety.

There is one operating natural gas-fired thermal power plant facility, the BEP, within the immediate vicinity of the SEP that staff considered for potential cumulative aviation impacts associated with thermal plumes. Operation of the SEP could create cumulative aviation impacts with the existing BEP because the locations of both facilities would be located within the arrival and departure pattern of air traffic using RY 8-26 from the Blythe Airport. Staff will address these issues in more detail in the FSA following discussions with the FAA, RCALUC, and EDA staff.

CONCLUSIONS AND RECOMMENDATIONS

Staff has analyzed the amended SEP's potential construction and operations impacts and concludes that the proposed amendment would not create any new significant impacts or substantially increase the severity of previously identified significant impacts to the regional and local ground transportation system. The mitigation for the licensed BEP II would still be applicable and Conditions of Certification **TRANS-1** through **TRANS-8** would not require any changes. For these aspects of the proposed SEP, the Commission may rely on the previous analysis for the BEP II and no supplementation is necessary.

Like the licensed BEP II, the amended SEP would generate thermal plumes that could pose aviation hazards to low-flying aircraft using the Blythe Airport. Compared to the licensed BEP II, the amended SEP's gas turbine design would increase the potential risk to light aircraft from plume turbulence. Condition of Certification **TRANS-9** was adopted by the Commission to avoid these impacts; however, at this time it is uncertain if all elements of **TRANS-9** are feasible.

Staff is proposing the SEP use dry cooling instead of a wet cooling tower for the SEP. Dry cooling would emit invisible thermal plumes rather than visible water vapor. A preliminary analysis for dry cooling, conducted by staff, shows the ACC critical plume velocity of 4.3 meters per second (m/s) is predicted to occur up to 1,500 feet AGL. Staff's preliminary analysis shows there would be a significant increase in plume velocity for dry cooling compared to the plume velocity predicted for a wet cooling tower.

Staff has determined that operation of the SEP could create cumulative aviation impacts with the existing BEP because the locations of both facilities would be located within the arrival and departure pattern of air traffic using RY 8-26 from the Blythe Airport.

The SEP could result in new traffic impacts from the use of evaporation ponds, which are known to attract birds and could increase bird strike hazards. This could impact aviation safety and result in the amended project being incompatible with the Blythe Airport and RCALUCP. These issues will be addressed more fully in the FSA.

Socioeconomics Figure 1 (refer to the **Socioeconomics** section of this document) shows the presence of an environmental justice population living within the project's six-mile buffer. Staff has not identified any significant adverse direct or cumulative traffic impacts that would affect the environmental justice population. Therefore, there are no traffic and transportation environmental justice impacts resulting from this project.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

At this time staff proposes a modification to **TRANS-9** to acknowledge the change of name for the project. As discussed above, additional changes to this condition may be necessary and, if so, will be reflected in the FSA. Modifications are shown in ~~strike-through~~ for deletions and **<u>bold underline</u>** for additions.

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 onsite 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;
- 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 linear facilities; 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 any time.

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.

TRANS-9 The project owner shall not commence construction of ~~BEP II~~ **<u>the SEP</u>** until the following are accomplished:

1. A remark is placed on the Airport's Automated Surface Observation System (ASOS), or equivalent broadcast, advising pilots to avoid low-altitude direct overflight of the power plant;
2. The VFR traffic pattern to runway 26 is changed from left-hand turns to right-hand turns; and
3. A runway, other than runway 26, is designated as the primary calm wind runway.

Verification: At least 60 days prior to the start of rough grading or construction, the project owner shall submit to the CPM documentation demonstrating the implementation of this condition.

REFERENCES

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ASE2015c. AltaGas Sonoran Energy Inc. Informational Hearing Power Point Presentation (TN 206239). Docketed 9/30/2015.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

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COB2015a. City of Blythe 2025 General Plan Circulation Element Website. http://www.cityofblythe.ca.gov/DocumentCenter/View/302. Accessed December 2015.

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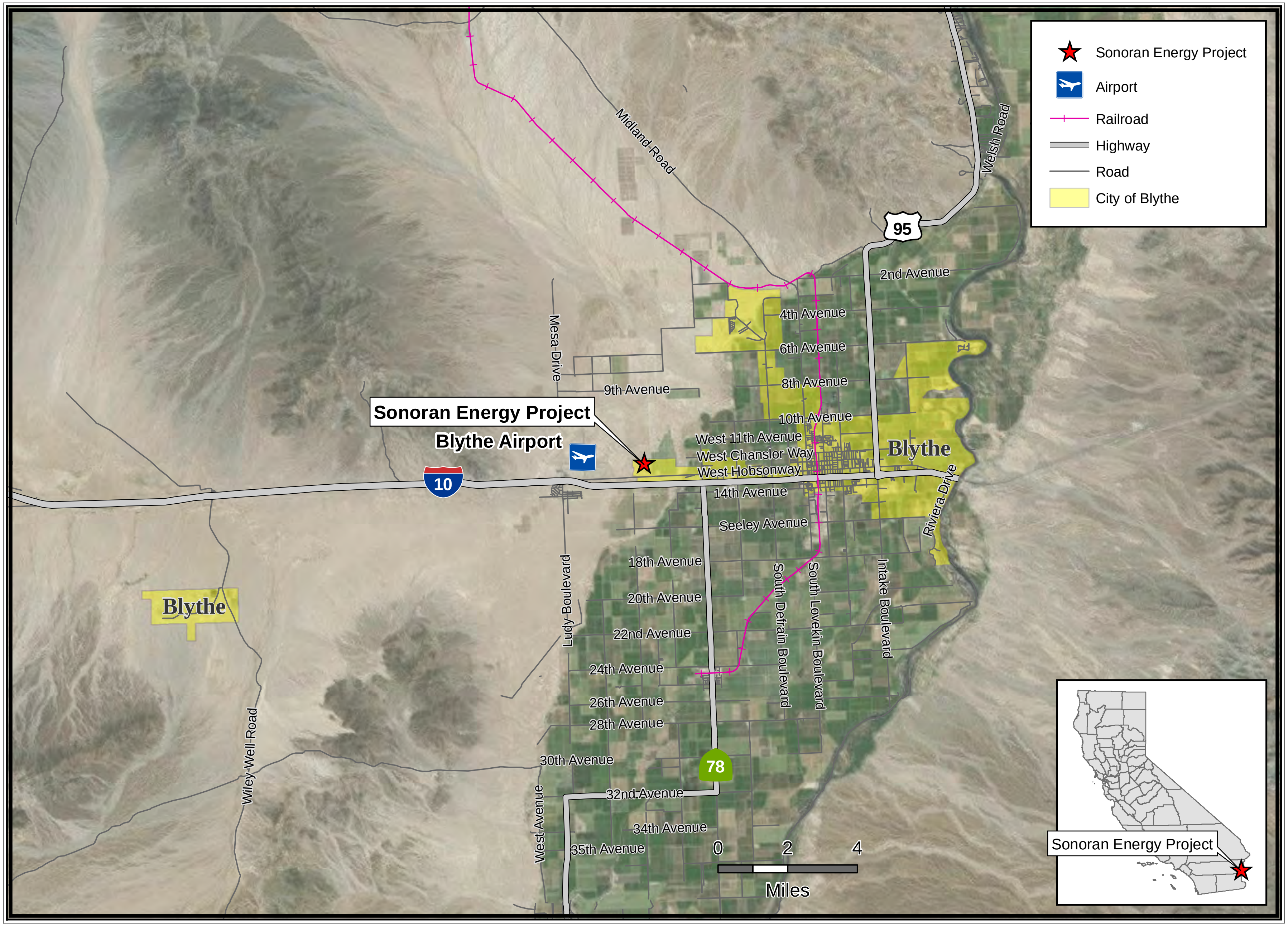
RCALUC 2015a. E-mail from Ed Cooper, Director Riverside County Airport Land Use Commission to Jim Adams, California Energy Commission. Dated December 14, 2015.

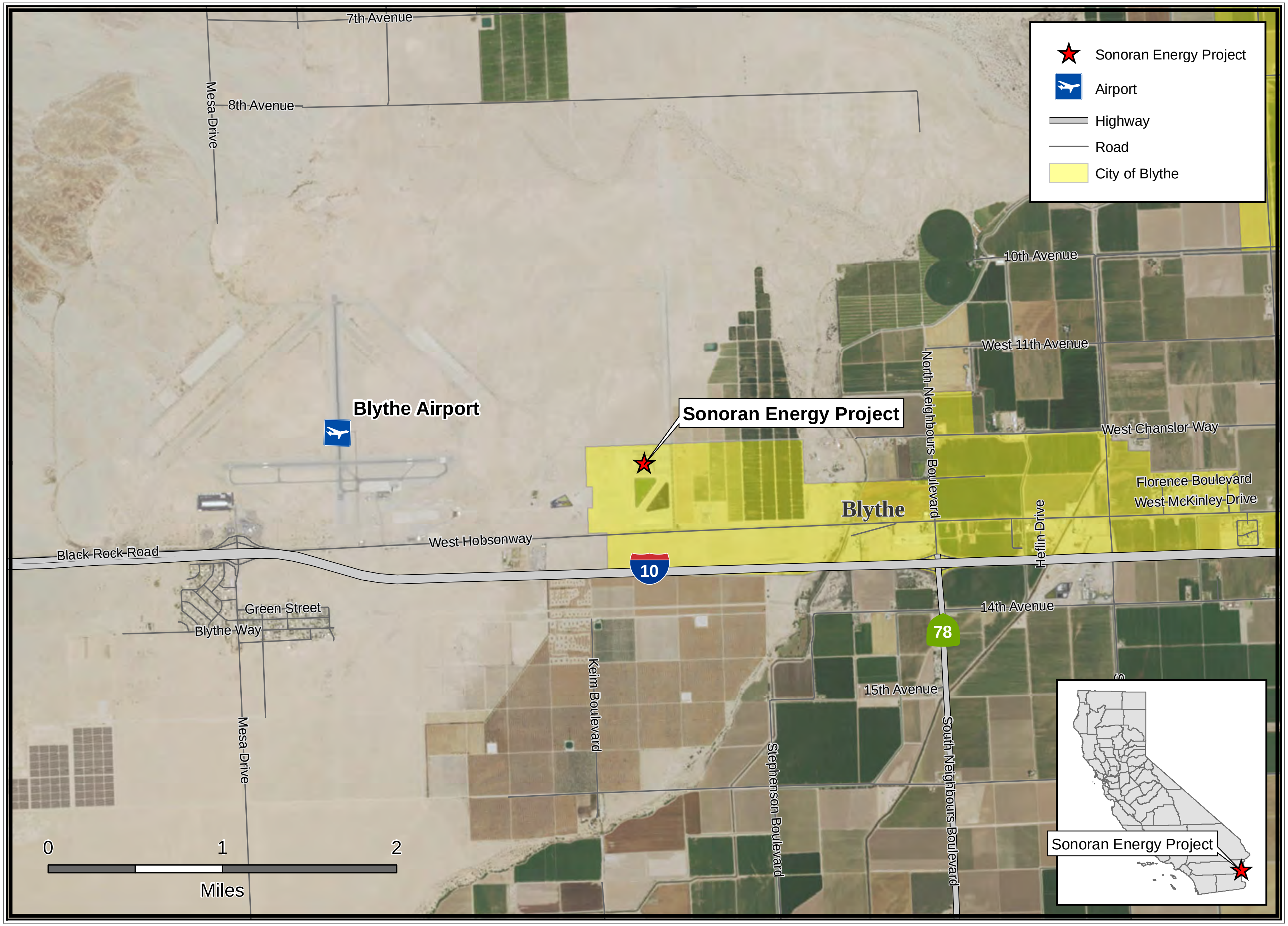
TRAFFIC AND TRANSPORTATION - FIGURE 1
Sonoran Energy Project - Regional Transportation Network



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Open Street Map data, California Department of Transportation data & ESRI Imagery

TRAFFIC AND TRANSPORTATION - FIGURE 2

Sonoran Energy Project - Local Transportation Network



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Open Street Map data, California Department of Transportation data & ESRI Imagery

SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
TRANSMISSION LINE SAFETY AND NUISANCE
Obed Odoemelam, Ph.D.

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Sonoran Energy Project (SEP) proposes project modifications that will not change existing **Transmission Line Safety and Nuisance (TLSN)** Conditions of Certification. Similar to the conclusions in the project's licensed Blythe Energy Project II (BEP II) 2005 Energy Commission Final Decision (2005 Decision), the potential impacts of the proposed Petition to Amend (PTA) would be less than significant. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Decision is necessary for **TLSN**. The Committee may rely upon the environmental analysis and conclusions of the 2005 Commission Decision with regards to **TLSN** and does not need to re-analyze them.

The proposed modifications would involve specific changes to the approved power transmission scheme as necessary to ensure implementation of applicable mitigation measures. Staff's assessment shows the proposed design and operational plan would not affect the ability of SEP to comply with the Laws, Ordinances, Regulations and Standards (LORS) given that the previously-approved conditions of certification would be retained. Staff are not proposing revisions to existing TLSN Conditions of Certification

INTRODUCTION

The safety and nuisance impacts from operating transmission lines depend on compliance with specific nuisance and safety LORS. Such compliance is ensured by maintaining these impacts within levels considered appropriate by the California Utilities Commission. The owner of the SEP established the adequacy of their design and operational plan before the Energy Commission which approved the proposal and specified the five conditions of certification necessary. The project owner is proposing the same BEP II compliance measures for the proposed SEP. Staff has reviewed the related Energy Commission Decision along with the owner's amendment request documents to determine whether or not the proposed modification would affect the ability of SEP to comply with applicable LORS.

SUMMARY OF THE DECISION

In its 2005 Decision (CEC 2005b), the California Energy Commission found the design and operational plan for the BEP II transmission line adequate to ensure operation without adverse safety and nuisance impacts, and for compliance with the LORS related to the safety and nuisance impacts. The Commission also found the plan adequate in its April 27, 2012 approval (2012 Order) of the amended version of BEP II.

The Decision concluded that implementation of the staff's proposed **TLSN** Conditions of Certification **TLSN-1** through **TLSN-5** would ensure that **TLSN** impacts would not cause any significant direct, indirect, or cumulative impacts and that the project would comply with the applicable LORS relating to **TLSN**.

As noted above, the 2009 amendment did not affect **TLSN** and the 2012 Order did not discuss this topic.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS COMPLIANCE

There have been no changes to the transmission line-related LORS of concern to staff since the Energy Commission's Decision was published in December 2005 regarding BEP II and in 2012 regarding the 2009 BEP II amendment.

ENVIRONMENTAL IMPACT ANALYSIS

As more fully described in the **Project Description** section, the proposed SEP is a facility with technological improvements to enhance operational efficiency while changing the point of connection between SEP's transmission lines and the area's electric power grid. As more fully discussed in the **Transmission System Engineering** section, the new connection is proposed to be made with a new 1,320-foot, overhead, 161-kV line stretching from SEP to a connection point within the existing Buck Boulevard substation to the southeast. From this substation, the generated power would be transmitted around the area at 230 kV or 161 kV. The Commission also found this same generation and transmission scheme adequate in its 2012 Order approving the amendment submitted on October 23, 2009 for the approved BEP II. This identifies the present SEP-related operation and transmission scheme as similar to the scheme already approved for BEP II in 2005 and its subsequent amendment in 2009.

The applicant has provided the support tower designs showing the height of the proposed towers to range from 85 feet to 110 feet above ground level, allowing for compliance with the National Electrical Safety Code (NESC), California Public Utilities Commission's (CPUC) General Order 95 (GO-95) and other applicable safety requirements. The transmission line for the Energy Commission-permitted BEP II facility would have been 2,100 feet in length with the power transmitted at 500-kV. The line would have stretched from BEP II to a formerly proposed 500-kV Keim substation.

COMPLIANCE WITH LORS

As discussed in staff's analysis for the permitted BEP II, current CPUC policy on minimizing the field and non-field impacts of any line is to design and operate the line according to the guidelines of the main area utility lines to which the line would be connected. The respective utilities in this case are the Western Area Power Administration (Western) and Southern California Edison (SCE). Since the proposed SEP line would be designed according to the respective requirements of GO-95, GO-52, and Title 8, Section 2700 et seq. of the California Code of Regulations, and operated and maintained according to current Western and SCE guidelines, staff considers the proposed design and operational plan to be in compliance with the applicable LORS.

CONCLUSIONS AND RECOMMENDATIONS

Since the proposed SEP's transmission line would be designed to minimize the safety and nuisance impacts of specific concern to staff and located in an area with no nearby residences, staff concludes that the proposed modification would not affect SEP's ability to comply with the applicable LORS.

CONDITIONS OF CERTIFICATION

Existing Conditions of Certification **TLSN-1** through **TLSN-5** will be sufficient to reduce impacts from the proposed amendment to a less than significant level, and ensure the project remains in compliance with applicable safety and nuisance LORS. Therefore, staff does not propose any modifications to the existing 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 any 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 after operations commence.

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.

REFERENCES

ASE2015a - AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652) Docketed on8/7/2015.

CEC2005a - California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2005b - California Energy Commission. Final Commission Decision. Docketed on 4/26/2015.

SONORAN ENERGY PROJECT (02-AFC-01C)

Petition to Amend Final Commission Decision
VISUAL RESOURCES
Jeff Juarez

SUMMARY OF CONCLUSIONS

Staff has reviewed the Petition to Amend (PTA or Petition) the Blythe Energy Project Phase II (BEP II) 2005 California Energy Commission (Energy Commission) Final Commission Decision (2005 Decision) for the proposed Sonoran Energy Project (SEP) to determine potential visual impacts and consistency with applicable laws, ordinances, regulations, and standards (LORS). Based on this review, staff determined that the proposed SEP would not create new significant visual impacts or make substantially more severe the significant visual impacts analyzed in the BEP II 2005 Decision, and that the proposed SEP would be in compliance with all applicable LORS, with effective implementation of the Conditions of Certifications approved in the BEP II 2005 Decision. None of the Conditions of Certifications are new or have been modified since the 2005 Decision.

Staff is proposing dry-cooling technology to replace the proposed project's wet-cooling system at the project site. In this project's Final Staff Assessment (FSA), staff will include a visual impact analysis of a dry-cooling system, or air-cooled condenser (ACC), should it become part of the proposed project.

In accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., titl. 14, § 15162), staff concludes that supplementation to the BEPII 2005 Final Decision is necessary for visual resources.

INTRODUCTION

The Petition includes the following key modifications related to visual resources:

- Replace the two Siemens SGT6-5000F combustion turbine generators (CTGs) with a single, more efficient General Electric (GE) Frame 7HA.02 CTG;
- Replace the Siemens steam turbine generators (STGs) with a more efficient single-shaft GE D652 STG;
- Replace two heat recovery steam generators (HRSGs) with one HRSG;
- Define a new point of electrical interconnection to the Southern California Edison (SCE) Buck Boulevard substation located on the adjacent Blythe Energy Project (BEP) project site via a new 1,320-foot long 161-kV transmission line;
- Reduce the size of the cooling tower from an 11-cell to a 10-cell tower in response to the reduced heat rejection requirements.
- Reduce the size of the brine concentrator from a tall, narrow structure to a relatively wide and short structure.

This analysis was conducted in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), in that new information of substantial importance has become available that indicates significant or potentially significant effects not discussed in the BEPII 2005 Final Decision. The information could not have been known at the time of the BEPII Final Decision, as it is based on events that occurred since the decision was published in December 2005. Staff analyzes the following new information in this analysis;

- New laws, ordinances, regulations, and standards (LORS) applicable to this Petition have been adopted by the city of Blythe;
- A new residence was built approximately 1 mile from the project site that would have a direct view of the SEP.

SUMMARY OF THE DECISION

BEP II 2005 DECISION

The BEP II was licensed in 2005. The most visible features of the BEP II included two 130-foot tall HRSG stacks, a 93-foot tall HRSG casing, a 98-foot tall brine concentrator, and a 60-foot tall generation building. The BEP II 2005 Decision analyzed seven Key Observation Points (KOPs) and determined that BEP II would produce adverse but less than significant impacts (with effective implementation of conditions of certification) at KOPs 1, 2, 3, 6, and 7. No visual impacts were identified at KOPs 4 and 5. The BEP II Final Decision found the proposed project in conformance with the applicable laws related to visual resources and determined that all potential adverse visual resource impacts will be mitigated to less than significant with implementation of Conditions of Certification **VIS-2**, **VIS-4**, **VIS-5**, **VIS-6**, and **VIS-7** (**VIS-1** [Construction Screening] and **VIS-3** [Site Surface Restoration], proposed by staff in the Final Staff Assessment, were determined unnecessary by the Commission and are labeled “Deleted” and “Deleted See BIO-5(9)” in the BEP II Final Decision).

2009 PETITION TO AMEND

The BEP II project was modified under the 2009 PTA, which was approved in 2012. The most substantial visual changes under the 2009 PTA included an increase in size of the cooling tower by 1,020 square feet and the addition of two parking lots. Staff reviewed the 2009 PTA and determined that the modifications would not result in or cause: a significant effect on visual resources, a change or deletion of a condition adopted by the Commission in the BEP II 2005 Decision, or noncompliance with any applicable LORS.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

LORS applicable to the proposed project have changed since the BEP II 2005 Decision. The following LORS related to visual resources are currently applicable to the Petition:

CITY OF BLYTHE GENERAL PLAN 2025

The city of Blythe adopted its current general plan in March 2007. The following visual resources-related policies of the City of Blythe General Plan 2025 are applicable to the proposed project:

City Form (Section 2.1)
Implementation Policy: “Maintain the successive unfolding of views to the mountains and the Mesa from the City and to the City from the Mesa along key routes through design guidelines and standards related to setback, building height, color and materials as well as landscaping along these corridors;”

Large-Scale Commercial and Industrial Projects (Section 2.5)
Policy 24: “Encourage a human scale in the design of large-scale projects. The perceived overall size of large projects should be mitigated to the extent possible through, for example, sensitive massing, appropriate scaling of building facades, articulation and organization of buildings, the use of color and materials, and the use of landscape screening;”

Policy 25: “Encourage innovative site design and treatment of surface parking areas. Surface parking areas should be organized and treated in such a fashion as to avoid the appearance of a ‘sea of asphalt.’ Landscaping should meet or exceed, if possible, a 50 percent shading requirement with large trees planted throughout the parking area as well as along the street and sidewalks. The use of porous paving and the integration of drainage features should be encouraged for reasons of environmental quality and to improve the visual appearance of parking areas, which are often more intrusive than the buildings they are intended to serve;”

Industry (Section 3.6)
Policy 18: “Achieve compatibility between industrial development and surrounding neighborhoods through buffering requirements and standards intended to minimize harmful effects of excessive noise, light, and glare and other adverse environmental impacts;”

Open Space Classifications (Section 6.1)
Policy 1: “Maintain hillsides and viable agricultural lands as open space for resource conservation and preservation of views;”

Policy 3: “Maintain existing views of the Mesa and Colorado River from roadways and public uses and other rights-of-way on the valley floor whenever feasible.”

Based on staff’s review, the proposed SEP would be in compliance with applicable LORS related to visual resources, including those of the City of Blythe General Plan 2025, with effective implementation of the Conditions of Certification **VIS-2**, **VIS-4**, **VIS-5**, **VIS-6**, and **VIS-7** approved under the BEP II 2005 Decision.

ENVIRONMENTAL IMPACT ANALYSIS

The SEP Petition proposes a new, approximately 1,320-foot long 161-kV transmission line that would extend to the north before traversing off-site to the east for connection to the existing SCE Buck Substation located on the adjacent BEP project site. The proposed linear interconnection would be approximately 800 feet shorter than that which was approved under the 2009 PTA.

The SEP proposed project's power block and ancillary structures would be located on the east side of the 76-acre project site, and just south of the existing BEP power plant structures located on the adjacent parcel to the east. The power block of the BEP II project was to be located in the center of the project site. This SEP Petition places the proposed power plant facilities closer to the existing BEP structures, for a more compact massing of power plant facilities.

As compared with the BEP II, the SEP Petition proposes an overall smaller, more compact power facility. The most substantial visual change between the two projects is the inclusion of one instead of two CTGs, as well as one HRSG. The proposed single HRSG exhaust stack would be 140-foot tall, as compared with the two 130-foot tall HRSG exhaust stacks of the BEP II. In addition, the single HRSG would be 120-foot tall, while the BEP II included two 93-foot tall HRSGs. The proposed HRSG would be approximately the same length and width as the licensed HRSGs.

The SEP proposes some smaller ancillary structures. The BEP II included a 98-foot tall, 17-foot diameter brine concentrator. The new structure would be 10 feet tall, 67 feet wide, and 103 feet long. In addition, the cooling tower, which increased in size under the 2009 PTA, would be reduced from an 11-cell to a 10-cell tower approximately 28 feet tall (reduced from 40 feet). Water supply and storage tanks would also be reduced in height. For instance, the largest of these structures, the raw water supply tank and the demineralized water storage tank, would be reduced in height from 40 and 43 feet, respectively, to 20 feet each.

A soda ash storage silo that was approved as part of BEP II would remain approximately 58 feet tall. The silo is not represented in the visual simulations prepared for BEPII or this Petition. Its location will be discussed further on in this analysis.

Staff requested that the applicant revise several of the visual simulations submitted as part of this Petition to illustrate the currently proposed project; the visual simulations had not been updated since the BEP II 2005 Decision and continued to show the BEP II structures. Of the original and revised visual simulations, staff chose KOPs 1 and 6 for analysis. The KOPs selected best represent the existing visual setting and visual change that would occur with the new HRSG and HRSG stack, and the overall project redesign. Staff did not consider KOPs 2, 3, 4, 5 and 7 in this analysis for the following reasons:

- KOP 1 is similar to KOP 2 in its representation of eastbound motorist views. KOP 2 is located on Hobsonway, located just south of the project site. KOP 1 is located along State Highway 10 (Hwy 10), which is approximately 1/4 mile south of and parallel to Hobsonway. The BEP II 2005 Decision concluded that the visual impacts at both KOPs would be less than significant with effective implementation of Conditions of Certification **VIS-4** and **VIS-5**. Based on staff's review, the overall visual effect of the SEP at KOPs 1 and 2 would be similar;

- KOP 3 was taken approximately 2 miles west of the SEP project site, adjacent to the Mesa Verde residential area. Based on staff's review, the proposed project redesign would hardly be visible from this distance, therefore it was not considered as part of this analysis;
- KOP 4 is located approximately 4.25 miles east of the project site, from a commercial area on the western edge of downtown Blythe. Based on staff's review, the proposed project redesign would hardly be visually distinguishable from this distance, therefore it was not considered as part of this analysis;
- KOP 5 was taken approximately 4.5 miles northeast of the project site, adjacent to the Rancho Ventana RV Resort and the Blythe Municipal Golf Course. Based on staff's review, the proposed project redesign would hardly be visible from this distance, therefore it was not considered as part of this analysis;
- KOP 7 is located approximately 1/2 mile east of the project site, along the north side of westbound Hwy 10. At this point, Hwy 10 traverses the eastern face of the Palo Verde Mesa. The KOP's position on the mesa is approximately 10 to 20 feet higher in elevation than the highway; the surface of the highway does not become flush with the grade of the mesa (and the project site does not become visible) until the viewer is more or less just south of the project site. Staff eliminated KOP 7 from further analysis because it does not represent motorist views along this portion of Hwy 10. Staff instead chose the revised KOP 6 to represent and analyze westbound motorist views from Hobsonway and Hwy 10.

See **Visual Resources (VR) Figure 1**, which identifies the KOP locations.

<u>KOP 1 – Eastbound Highway 10</u>

This revised KOP represents views from eastbound Hwy 10. The KOP is located approximately 1/2 mile southwest of the project site and 3/4 mile from the proposed power block; it is roughly 800 feet west of the original KOP 1 location. The view is to the northeast. The existing condition photo (**VR Figure 2a, Existing Condition**) depicts BEP and its desert setting in the middleground, Hwy 10 and agriculture-related structures and vehicles in the foreground, and mountains in the distant background. The visual setting described for this KOP in the BEP II 2005 Decision has not substantially changed and is applicable to this analysis. For viewers at KOP 1, a 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.

The revised simulation for KOP 1 depicts the proposed SEP power block to the right of BEP (**VR Figure 2b**, **Simulated View**). As depicted, the proposed SEP power block, HRSG exhaust stack, cooling tower, transmission lines and towers, and ancillary structures would be consistent with the lines and forms established by the existing BEP power plant; overall, the lines and forms of the SEP appear cleaner and more modern. The colors and materials of the proposed facility would be consistent with those of the existing power plant.

In comparison to BEPII (**VR Figure 2c, BEP II Simulation)**, the proposed SEP would be visually similar to the licensed power plant facility, in terms of color, materials, and line and form. In the revised visual simulation, the proposed and existing power plant components appear as one continuous industrial facility; depending on the position and viewing angle of motorists on Hwy 10, the proposed SEP and existing BEP power plant facilities may appear more or less in alignment.

As previously mentioned, the SEP proposes only one 120-foot tall HRSG and one 140-foot tall HRSG exhaust stack, while the licensed BEP II included two 93-foot tall HRSGs and two 130-foot tall stacks. As shown in the proposed SEP and BEP II simulations, the difference in height between the proposed and licensed exhaust stacks is nominal and would not produce a potentially significant visual impact. And although the proposed single HRSG would be approximately 30 feet taller than the previously licensed HRSGs, the difference in height would not substantially intensify the visual effect of the proposed power block's profile. For comparison purposes, the height of the HRSGs and exhaust stacks at the existing BEP project are the same as those licensed for BEP II.

The major structures of the proposed SEP would be taller but fewer than those of BEPII, resulting in an overall smaller project profile and footprint. In comparison to BEP II, the proposed SEP would not create an increase in visual contrast or dominance, nor would the proposed HRSG and exhaust stack further obstruct views of the region's mountains and surrounding landscape. From KOP 1, the overall visual change that would be created by SEP would be similar to that of BEP II. Staff believes this assessment of the visual effect of SEP extends to KOP 2, and that the overall visual change perceived from that viewpoint would be similar to that of KOP 1.

The proposed 58-foot tall, 20-foot wide soda ash storage silo that is not shown in the visual simulations would be located roughly 300 feet southwest of the power block, in the brine concentrator/wastewater treatment equipment area (**VR Figure 3, Legend No. 61**). From KOP 1, the silo would be located to the right of the proposed power block (at a distance roughly equal to length of the power block).

The height of the silo would be less than half the height of the exhaust stack, and approximately the same diameter. From this viewpoint, the silo would be visible and appear as part of the cluster of existing and proposed industrial elements; its color, materials, and form would be similar to that of both the proposed and BEP structures. Staff does not anticipate the silo having a substantial visual effect on the visual quality from KOP 1.

Staff concludes, consistent with the analysis in the BEP II 2005 Decision, that the low-to-moderate visual change that would be perceived from KOP 1 and the moderate-to-high visual change that would be perceived at KOP 2 would produce a *less than significant impact* with effective implementation of Conditions of Certification **VIS-4** and **VIS-5**.

KOP 6 – Westbound Hobsonway

The revised KOP 6 is located 1/2 mile east of the original KOP 6 location. It was chosen to represent a view that would better capture the context of both the proposed SEP and existing BEP projects. Staff chose a viewpoint that would present the proposed and existing projects side by side for analysis purposes. In addition, the viewpoint more adequately represents views of westbound Hobsonway motorists traversing the Palo Verde Mesa.

The revised KOP 6 is located approximately 3/4 mile east of the SEP site. The proposed SEP power block would be positioned in a north-south orientation right adjacent to the project site's eastern boundary. The view is to the northwest. The existing condition photo (**VR Figure 4a, Existing Condition**) depicts BEP in the background on the far right side of the view, the edge of Hobsonway and utility poles and lines in the foreground, and the transmission infrastructure at the Western Area Power Administration Blythe substation in the middleground. In the distance are the lower ridgelines of the south end of the McCoy Mountains.

The visual setting described for the original KOP 6 in the BEP II 2005 Decision is similar to that of the revised KOP and mostly applicable to this analysis. The low-to-moderate visual quality and viewer concern assessed at the original KOP 6 applies at the revised KOP 6; however, the assessed visual sensitivity at the revised KOP 6 increases from low-to-moderate to moderate. This is due to the new location of KOP 6, and that the viewpoint now represents views from a residence that had not been built at the time of the BEP II 2005 Decision.

The revised KOP 6 indicates the slightly longer duration of view and higher viewer exposure for westbound Hobsonway motorists as they traverse the Palo Verde Mesa toward the project site. As motorists on both Hobsonway and Hwy 10 travel west and past the existing substation, the project site would become more visible against the backdrop of the McCoy Mountains.

The view from KOP 6 would be similar for the residence. Since the BEP II 2005 Decision, at least one residence was built (in 2008) approximately 1 mile east of the SEP and BEP project sites. The one-story, single-family residence is situated within a designated rural community area of unincorporated Riverside County that allows single-family residences on large lots. The residence is located approximately 3/4 mile northwest of the viewpoint. It is positioned on the Palo Verde Mesa and is west-facing with a clear line of sight to the SEP project site (and BEP). The area between the residential property and the project site is characterized by low-level agricultural vegetation. The view from the residence is expansive, with the highest ridgelines of the McCoy Mountains off to the northwest (not shown in **VR Figure 4a**).

The visibility of the project site from the residence is high and the duration of view is considered high. The overall viewer exposure is moderate-to-high. For westbound motorists and the residence, the overall visual sensitivity from KOP 6 and the surrounding area is considered moderate. *The revised visual sensitivity for KOP 6 does not change the overall visual change created by the proposed SEP,* as is discussed below.

The revised simulation for KOP 6 (**VR Figure 4b**, **Simulated View**) depicts the proposed SEP power block in the center of the view, beyond the substation transmission facilities and to the left of BEP. From this viewpoint, the upper half of the proposed HRSG would be visible, while the exhaust stack less so; the stack height appears similar to that of the existing substation transmission structures. The proposed transmission towers and lines are visible to the right of the view, between the existing transmission structures and BEP. Portions of the cooling tower, located beyond the power block, would be perceptible. The soda ash storage silo, which would be located to the left of the power block, may be noticeable but would likely not attract attention. From this viewpoint, the colors, materials, and lines and forms of the proposed SEP structures would be compatible with those of the existing BEP power plant and substation facilities.

The difference in height between the proposed and BEP II HRSGs and exhaust stacks would not be decipherable from KOP 6 and its vicinity. From this viewer's angle and distance, the height of the proposed structures would appear very similar to those of BEP. Even as motorists travel closer to the project site and past the existing substation transmission facilities, the change in height of the proposed project's major structures would not be noticeable and would not intensify their overall visual effect.

Although the revised KOP 6 is located 1/2 mile east of the original KOP 6 analyzed in the BEP II 2005 Decision, similar conclusions related to the visual impacts of BEP apply here. In comparison to BEP II, the SEP would not create an increase in visual contrast or project dominance, nor would the proposed HRSG and exhaust stack further obstruct views of the mountains and surrounding landscape. From the revised KOP 6, the overall visual change that would be created by SEP would be similar to that of BEP II. This assessment of the overall visual change that would be perceived by westbound Hobsonway motorists extends to anticipated motorist views from westbound Hwy 10. From Hwy 10, the overall visual change of the SEP, in comparison to BEP II, would be similar.

For the residence, the introduction of a new power facility to the left of BEP would have a visual effect similar to that presented in the BEPII Final Decision for the original KOP 6. The proposed SEP would create a moderate-to-high visual contrast, co-dominant-to-dominant project dominance, and moderate view blockage. As proposed, the SEP would result in a moderate-to-high visual change.

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 the revised KOP 6 would cause a *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 of SEP by ensuring that the proposed structures are surface treated and that their industrial character softened by landscape screening.

CUMULATIVE IMPACTS

As defined in Sections 15130 and 15355 of the CEQA Guidelines (Cal. Code Regs., tit. 14, § 15130, 15355), 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.

The BEP II 2005 Decision considered the BEP II in combination with multiple existing and proposed projects. The BEP II 2005 Decision determined that the BEP II visual impact, combined with the visual impacts resulting from existing and future projects, would not be cumulatively considerable, and would not result in a significant cumulative impact to visual resources.

Since the BEP II 2005 Decision, staff's updated cumulative project list identifies the Blythe Energy Project Phase III (Irish Energy Project or IEP) as a reasonably foreseeable project. Of those projects recently added to the list, staff believes this future project may produce a cumulative visual impact that could be cumulatively considerable when considered in the context of the BEP and SEP projects.

An Application for Certification (AFC) for the IEP has not been submitted, and staff does not have any details on the project to consider its visual effects. However, an additional energy-related development project located within 1 mile of the BEP and SEP projects may further diminish the visual quality of the Palo Verde Mesa and views of the surrounding mountains. If and when an AFC is submitted, staff will need to examine that project's visual impacts and their cumulative effects on nearby public roads, recreational areas, and any new residential development that may be constructed in the area of the project site.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the proposed amendment will not produce new or make substantially more severe any significant or potentially significant visual impacts, and that the proposed project will be in compliance with all applicable LORS, with effective implementation of the Conditions of Certification **VIS-2**, **VIS-4**, **VIS-5**, **VIS-6**, and **VIS-7** approved in the BEP II 2005 Decision. None of the Conditions of Certifications are new or have been modified since the BEP II 2005 Decision.

Staff is proposing dry-cooling technology to replace the proposed project's wet-cooling system at the project site. In this project's FSA, staff will include a visual impact analysis of a dry-cooling system, or air-cooled condenser (ACC), should it become part of the proposed project.

To conduct its visual analysis, staff will assess a conceptual ACC unit modeled after that which was proposed for the Palmdale Energy Project (PEP). While that project proposed a combined-cycle system with a two-on-one configuration, an ACC for the one-on-one-configured SEP would be similar in size to PEP's dry-cooling unit, due to the steam-cycle capacity of the proposed project's steam turbine generator.

The estimated size of the conceptual ACC that staff will analyze is 130-feet tall, 347-feet long, and 181-feet wide. Staff anticipates that the ACC would most likely be located just north of the proposed power block location.

PROPOSED CONDITIONS OF CERTIFICATION

CONSTRUCTION LIGHTING

VIS-1 Deleted. See BEP II 2005 Decision.

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.

VIS-3 Deleted. See **BIO-5(9)** See BEP II 2005 Decision.

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 along the southern boundary of the BEPII site that reduces the visibility of the power plant structures and complies with local policies and ordinances consistent with the landscaping at BEP. Trees and other vegetation consisting of informal groupings of fast-growing native species shall be strategically placed and of sufficient density to visually soften the industrial character of the power plant structures within the shortest feasible time. If any landscaping is installed along the western and northern boundaries of the BEPII site, only native species shall be used.

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.

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: Prior to installation of the sign, the project owner shall provide a copy of the plans for the sign to the City of Blythe for review and comment and to the CPM for review and approval.

REFERENCES

ASE 2015a. AltaGas Sonoran Energy Project Inc. Blythe Energy Project Phase II Petition to Amend Final Decision (02-AFC-01C). Docketed August 7, 2015. (TN# 205652)

ASE 2015b. AltaGas Sonoran Energy Project Inc. Sonoran Energy Project Data Responses Set 1. Docketed November, 12, 2015. (TN# 206606)

CEC 2005. Blythe Energy Project Phase II Final Commission Decision. Publication # CEC-800-2005-005-CMF. Docketed December 14, 2005.

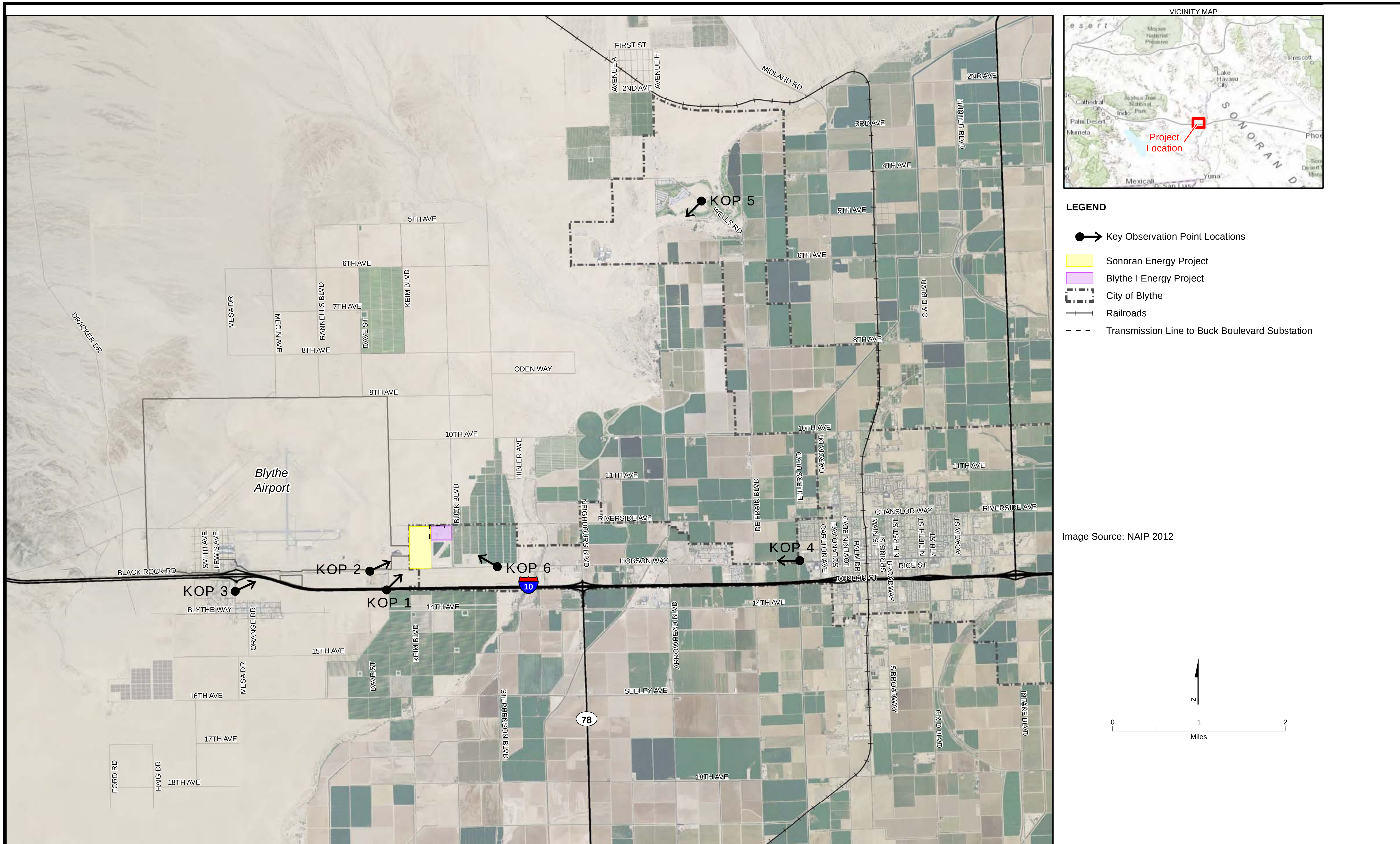
CEC 2005. Energy Commission Final Staff Assessment for the Blythe Energy Project Phase II. Publication # CEC-700-2005-007-CMF. Docketed April 29, 2005.

CEC 2001. Final Commission Decision on the Blythe Energy Project. Publication # CEC-800-2010-009-CMF. Docketed September 23, 2010.

City of Blythe. 2007. City of Blythe General Plan 2025.

VISUAL RESOURCES - FIGURE 1

Sonoran Energy Project - Key Observation Point (KOP) Locations



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Petition to Amend. - Figure 1-R

VISUAL RESOURCES - FIGURE 2a

Sonoran Energy Project - Revised KOP 1- Eastbound Highway 10 - Existing Condition

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Petition to Amend - Figure 2a-R

VISUAL RESOURCES - FIGURE 2b
Sonoran Energy Project - Revised KOP 1- Eastbound Highway 10 - Simulated View

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Petition to Amend - Figure 2b-R

VISUAL RESOURCES - FIGURE 2c
Sonoran Energy Project - KOP 1- 2005 BEP II Simulated View

SOURCE: Petition to Amend - Figure 2b-R

VISUAL RESOURCES - FIGURE 3
Sonoran Energy Project - General Site Arrangement

VISUAL RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Petition to Amend

VISUAL RESOURCES - FIGURE 4a

Sonoran Energy Project - Revised KOP 6 - Westbound Hobsonway - Existing Condition

VISUAL RESOURCES - FIGURE 4b

Sonoran Energy Project - Revised KOP 6 - Westbound Hobsonway - Simulated View

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Petition to Amend - Figure 7b-R

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SONORAN ENERGY PROJECT (02-AFC-1C)
Petition to Amend Final Commission Decision
WASTE MANAGEMENT
Ellen Townsend-Hough

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Sonoran Energy Project (SEP) proposes to modify the project which will necessitate modification to existing **Waste Management** Conditions of Certification. Similar to the conclusions in the project's licensed Blythe Energy Project Phase II (BEP II) 2005 Energy Commission Final Decision (2005 Decision), the potential impacts of the proposed PTA would be less than significant. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Decision is necessary for **Waste Management**. The Committee may rely upon the environmental analysis and conclusions of the 2005 Decision with regards to **Waste Management** and does not need to re-analyze them.

Management of the waste generated during construction and operation of the proposed amended SEP would not generate a significant adverse impact for Waste Management. Like the licensed BEP II 2005 Decision approved by Energy Commission on December 14, 2005, there is sufficient landfill capacity for the amended SEP. The Commission Decision was not altered or affected by the 2009 Petition to Amend (PTA) and the resulting 2012 Order. There is no evidence of soil contamination on the project site. As with the licensed BEP II, the amended SEP would be consistent with the applicable waste management laws, ordinances, regulations, and standards (LORS) if staff's proposed conditions of certification are implemented.

INTRODUCTION

In this section, Energy Commission staff discusses potential impacts of the August 6, 2015 SEP PTA in relation to waste management. The purpose of this analysis is to determine whether the PTA would require new mitigation or modified **Waste Management** conditions of certification.

SUMMARY OF THE DECISION

The Commission Decision for the project did not find any immitigable impacts to waste management. The Decision required conditions **WASTE-1** through **WASTE-7** to account for the different types of wastes that will be generated during the construction and operation of the proposed project and must be managed appropriately to minimize the potential for adverse human and environmental impacts. This analysis assesses the adequacy of the waste management plan with respect to handling, storage and disposal of these wastes.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

New LORS that would apply to SEP since the licensing of BEP II are discussed below.

2008 California Green Building Standards Code. This code requires all construction projects to develop a recycling plan to divert and/or recycle at least 50 percent of waste generated during construction, (CalGreen Building Standards Code Section 708 construction Waste Reduction, Disposal and Recycling). Effective Jan. 1, 2011, California's Green Building Standards Code (CALGreen) required the diversion of at least 50 percent of the construction waste generated during most "new construction" projects (CAL Green Sections 4.408 and 5.408).

Title 14, Division 7, Chapter 9.1 Section 18835. This Chapter implements Mandatory Commercial Recycling pursuant to §42649 of the Public Resources Code. The purpose of the regulations is to reduce greenhouse gas emissions by diverting commercial solid waste for recycling and expanding the opportunity for additional recycling services and recycling manufacturing facilities in California.

Prior to construction and operation, the project owner would be required to develop and implement Construction and Operation Waste Management Plans, per proposed Condition of Certification **WASTE-5**. Staff would review these plans to ensure compliance with local LORS.

ANALYSIS OF IMPACTS

Staff has reviewed the SEP PTA to determine whether there are any potential new impacts that are not analyzed in the original project license. Staff has conducted the necessary analysis to determine whether a change addition, deletion, or new condition of certification would be necessary to address potential impacts. The evaluation of the proposed project and the mitigation measures are intended to reduce the risks and environmental impacts associated with handling, storing and disposing of waste.

SITE CONDITIONS

The modified project would consist of: one gas-fired General Electric combustion turbine generator, one supplemental-fired heat recovery steam generator, a smaller cooling tower, and related ancillary equipment. Other equipment and facilities to be constructed are an auxiliary boiler, water treatment facilities, evaporation ponds, and emergency services, administration, and maintenance buildings. The SEP project site is the same as previously licensed for BEP II.

Most of the proposed modifications would be performed within the same footprint as the licensed BEP II project. SEP would be located within the City of Blythe, in eastern Riverside County, California on a previously disturbed site adjacent to the existing BEP.

A Phase I Environmental Site Assessment (ESA) for SEP was prepared by AECOM and dated May 2015 (ASE2015a, Appendix 3.10). The ESA was completed in accordance with the American Society for Testing and Materials Standard Practice E 1527-13 for ESAs (ASTM E-1527-13). The primary purpose of an ESA is evaluating whether there are any Recognized Environmental Concerns (REC) on or around a property. An REC is the presence or likely presence of any hazardous substances or petroleum products on a property under the conditions that indicate an existing release, past release, or a material threat of a release of any hazardous substance or petroleum products into structures on the property or into the ground, groundwater, or surface water of the property.

The project would be constructed on up to 34 acres within the existing 76-acre licensed site. The 76-acre parcel consists of the following land uses:

- Northern portion of the site is a fenced-off 1940, World War II, 10-acre military solid waste dump;
- Northeast portion of the property was a former laydown yard for Blythe Energy Center (BEC I);
- BEC I is located on the eastern portion of the property; and
- The southern portion of the site is mainly graded land bordered by a man-made earthen drainage ditch.

The fenced-off military waste dump site was sampled and elevated levels of lead were detected. The concentration found in the dump was 570 milligram per kilogram (mg/kg), which exceeded the California Human Health Screening Level (CHHSL) for industrial soil of 320 mg/kg. No other RECs, historical RECs or controlled RECs were found on the SEP project site (ASE2015a, Appendix 3.10).

There are currently no structures on the proposed plant location. The project site is enclosed by a permanent exclusionary fence and is located on fill material. The electrical interconnection is via a 1,320- foot 161-kV line connecting to the existing Buck Boulevard substation to tie into an existing transmission line (ASE2015a, Section 3.13.1). The interconnection will be built on the previously surveyed SEP site; therefore, no additional impacts to soils are anticipated. SEP would share some facilities with the existing BEP, including an existing 16-inch natural gas line located on the south side of the BEP property boundary (ASE2015a, Section 2.1.2).

There is no evidence of petroleum products, hazardous materials, polychlorinated biphenyls, aboveground storage tanks, underground storage tanks, solid waste or hazardous waste located on the project site. If, however, contaminated soil is unearthed, there would be a qualified environmental professional on site, as required in accordance with condition of certification **WASTE-1**, to write evaluate and propose remedial action, in accordance with **WASTE-2**. **WASTE-6** requires all employees receive hazardous-waste-related training that focuses on the recognition of potentially contaminated soil and/or groundwater and contingency procedures for management. These conditions would ensure there are no impacts to health and safety of workers and the environment from contaminated soil and groundwater if encountered.

CONSTRUCTION WASTE

Site preparation, along with construction of the generating plant and associated facilities, would generate a variety of nonhazardous and hazardous wastes.

The project owner estimates that the amended project would produce the same amount of waste as the original BEP II project. Nonhazardous waste streams from construction may include packing paper, cardboard, wood, glass, and plastics. These would be generated from packing materials, waste construction lumber, insulation materials, and empty containers. Construction of SEP would produce approximately 90 tons of these wastes. In addition, an estimated 50 tons of waste asphalt or concrete would be generated during construction of foundations, parking lots, and roads (ASE2015a, Table 3.13-1). 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. These wastes would be recycled where practical, Title 14, Division 7 Chapter 9.1, Section 18835, with the rest discharged to the Blythe Sanitary Landfill (BEP II 2002d).

Up to 25 tons of metal wastes from welding and cutting operations, packing materials, trim, and empty containers and drums would also be generated (ASE2015a, Table 3.13-1). This also includes aluminum and copper electrical wiring waste from the power plant, substation, and transmission lines. These wastes would be recycled through scrap metal brokers with the remainder disposed to the Blythe landfill (CBE2002b, Section 7.11.2.1.1).

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. Such wastes would be collected in hazardous waste accumulation containers near the point of generation. The containers would be taken to the construction contractor’s hazardous waste storage area and within 90 days (CCR Title 22, Section 66262.34) would be delivered to an authorized hazardous waste management facility (CBE2002b, Section 7.11.2.1.1). These wastes would be managed in accordance with local codes and requirements to ensure there would be no impacts to the health and safety of workers and the environment. See the **Hazardous Materials** section of this document for further analysis of hazardous materials.

OPERATION WASTE

Under normal operating conditions, the proposed facility would generate both nonhazardous and hazardous wastes. Nonhazardous wastes generated during plant operation include trash, office wastes, and empty containers, broken or used parts, used packing material, and used filters. It is estimated that about 65 cubic yards annually of such wastes would be generated (ASE2015a, Table 3.13-2). Metal parts and other materials such as paper, aluminum, and plastic would be recycled through brokers, when possible (ASE2015a, Table 3.13-2). Nonrecyclable solid wastes would be transported to the Blythe Sanitary Landfill.

Routine project operation would generate a variety of hazardous wastes. Table 3.13-2 of the PTA summarizes the hazardous wastes that are anticipated to be routinely generated, along with estimated amounts and planned management methods (ASE

2015a, Table 3.13-2). Much of the hazardous waste generated is suitable for recycling. Used turbine lubricating oil would be collected for recycling by a licensed waste oil recycler (ASE 2015a, Table 3.13-2). Every three to four years, air pollution control catalysts must be replaced in order to maintain their control efficiency. Spent catalyst would be returned to the manufacturer for metals reclamation or disposal. Liquid hazardous wastes consisting of solvents containing hazardous levels of heavy metals would be generated during pre-operational and periodic flushing and cleaning of pipes and the heat recovery steam generator (HRSG). A contractor would be used for such cleaning operations and would transport liquid wastes to an offsite facility licensed to manage such wastes.

BEP II is currently licensed to use a Zero Liquid Discharge System (ZLD) for wastewater discharge. This system would recycle wastewater and generate a solid waste that would need to be disposed of at a landfill depending on whether the waste was classified as hazardous or non-hazardous. Staff proposes Condition of Certification **WASTE-7** which would require the ZLD waste be classified and disposed of in the appropriate landfill. For additional information on liquid waste refer to the **Soil and Water Resources** section.

Approved Conditions of Certifications **WASTE-3**, **4**, and **5** would apply to the proposed construction and operation waste and ensure appropriate management. **WASTE-3** would require that a hazardous waste generator identification number be maintained during construction and operation. **WASTE-4** would require that all enforcement actions related to project waste management be reported. **WASTE-5** would require the project owner to implement a Construction Waste Management Plan and an Operation Waste Management Plan for all wastes generated during construction and operation of the facility. These conditions would ensure compliance with local LORS and that there are no impacts from waste management at the site.

IMPACT ON EXISTING WASTE DISPOSAL FACILITIES

The nearest landfill to SEP is the Blythe Sanitary Landfill in Riverside County. The landfill is located seven miles north of the City of Blythe. The Blythe Sanitary Landfill has approximately 4.2 million cubic yards of remaining capacity. The estimated date of closure for the Blythe Sanitary Landfill is June 2047. In addition, the Riverside County Department of Waste Resources operates six landfills, and maintains a contract agreement for waste disposal for an additional landfill. The remaining capacity of the combined Riverside County landfills is over 39 million cubic yards[1].

Two operating Class I landfills are located in California, at Kettleman Hills Facility in King’s County, and the Clean Harbors Buttonwillow in Kern County. 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.

[1] http://www.calrecycle.ca.gov/SWFacilities/Directory/SearchList/List?COUNTY=Riverside&FAC=Disposal&OPSTATUS=Active&REGSTATUS=Permitted

There is sufficient non-hazardous and hazardous landfill capacity for the proposed SEP. The approximate amount of the nonhazardous waste during construction and operation would be 1,100 cubic yards and less than five cubic yards per year, respectively. The amount of hazardous waste generated during construction and operation would be less than five cubic yards per year[2]. Much of the hazardous waste generated during facility construction and operation would be recycled, such as used oil and spent catalysts. The nonhazardous and hazardous wastes generated by the SEP project would consume less than 1 percent of the remaining Class I and Class III permitted capacity. Therefore, impacts from disposal of SEP wastes would also have a less than significant impact on the remaining capacity at Class III and 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.

CONCLUSIONS AND RECOMMENDATIONS

Management of the waste generated during construction, and operation of SEP would not result in any significant adverse impacts and would comply with applicable waste management LORS, if the measures proposed in the staff's analysis are implemented. The implementation of the current conditions of certification for SEP would mitigate impacts to below significance for the construction and operation of the project.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Staff concludes that there would not be any significant waste management impacts not previously analyzed, or an increase in severity of environmental impacts. Staff recommends the mitigation as proposed in the **Waste Management** Conditions of Certification Decision. The existing conditions of certification are adequate to ensure there would be no unmitigated significant impacts in the PTA.

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.

[2] Staff use construction and operation waste estimates in Tables 3.13-1 and 13-2 and used a factor of 300 pounds per cubic feet to convert estimates in to cubic yards.

<u>Verification:</u> 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.

<u>Verification</u>: 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.

<u>Verification</u>: 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.

<u>Verification</u>: 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:

1. A description of all waste streams, including projections of frequency, amounts generated and hazard classifications; and
2. 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 involved in earth disturbance for construction purposes in previously undisturbed areas 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 annual compliance report regarding the classification of the wastes and the treatment/disposal methods utilized.

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CBE2002a. Caithness Blythe Energy, Inc. Application for Certification (AFC), Vol. 1 & Vol. 2. (TN 24604). Docketed on 02/19/2002.

CBE2002b. Caithness Blythe Energy, Inc. Revised Application for Certification for Blythe II. (TN 26100) Docketed on 07/03/2002.

CBE2009a. Caithness Blythe Energy, Inc. Petition to Amend (TN 53798). Docketed on 10/26/2009.

CBE2010a. Caithness Blythe Energy, Inc. Supplement #1 to Amendment (TN 55438). Docketed on 2/16/2010.

CBE2011a. Caithness Blythe Energy, Inc. Blythe II Amendment Supplement #3 (TN 62479). Docketed 10/4/2011.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2012a. California Energy Commission. 2009 Petition to Amend – Staff Analysis (TN 60499). Docketed on 3/12/2012.

CEC2012b. California Energy Commission. Commission Order Approving 2009 Petition to Amend (TN 64945). Docketed on 4/26/2012.

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SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision

WORKER SAFETY/FIRE PROTECTION

Brett Fooks

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Sonoran Energy Project (SEP) proposes to modify the project which will not necessitate modification to the existing set of **Worker Safety/Fire Protection** Conditions of Certification. Similar to the conclusions in the project's licensed Blythe Energy Project II (BEP II) 2005 Energy Commission Final Decision (2005 Decision), and the 2012 Amendment Decision (2012 Order) the potential impacts of the proposed PTA would be less than significant. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that that the committee may rely upon the environmental analysis and conclusions of the 2005 Decision and 2012 Order with regards to **Worker Safety/Fire Protection** and does not need to re-analyze them.

Staff determined that only one of the laws, ordinances, regulations, and standards (LORS) applicable to the project have changed since the 2012 Order. The one LORS that has changed is an update of the adopted California Fire Code. Staff further proposes a new Condition of Certification **WORKER SAFETY-7** that would clarify that conformance to the recommended practices of fire protection standard NFPA 850 is required.

INTRODUCTION

The purpose of this analysis is to determine whether this PTA would require new mitigation or modified **Worker Safety/Fire Protection** conditions of certification. The project site for SEP is the same as the previously licensed, and amended, BEPII. The proposed modifications would be performed within the same footprint as the licensed BEPII project. SEP would be located within the City of Blythe, in eastern Riverside County, California on a previously disturbed site adjacent to the existing Blyth Energy Project (BEP).

The affected environment has not substantially changed since the 2005 Decision. The project would be constructed on 34 acres with the existing 76-acre licensed site. The 76-acre SEP site is bounded to the north by Riverside Avenue, to the east by the existing BEP facility, and to the south by Hobson Way. There are currently no structures to the west of the proposed plant location. The project site is enclosed by a permanent exclusionary fence and is located on fill material. The electrical interconnection is via a 161-kilovolt (kv) line connecting to the existing Buck Boulevard substation to tie into an existing transmission line. The interconnection will be built on the previously surveyed SEP site.

SUMMARY OF THE DECISION

The Commission's 2005 Decision and subsequent 2012 Order found that industrial workers at the proposed facility would operate equipment, handle hazardous materials, and face other workplace hazards that could result in accidents or serious injuries. The worker safety and fire protection measures for this project would be designed to either eliminate or minimize such hazards through special training, use of protective equipment or implementation of procedural controls. With adoption of the proposed conditions of certification, the Commission found that the project would comply will all applicable LORS and would not result in any unmitigated significant impacts.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

Only one LORS applicable to the project has changed since the 2005 Decision was adopted and amended. The latest version of the California Fire Code has changed and the updated version of the code is shown in the table below.

Worker Safety and Fire Protection Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Local (or locally enforced)	
City of Blythe Municipal Code Chapter 15.24 – California Fire Code	The City of Blythe Fire Department enforces the 2013 version of the California Fire Code (Chapter 15.24.010)

ENVIRONMENTAL IMPACT ANALYSIS

Staff has reviewed the PTA for potential environmental effects and consistency with applicable LORS. Staff has determined that the worker safety and fire protection impacts of the proposed modified SEP would be the same or less than significant with the proposed mitigation than those described in the current Decision. However, staff would like to clarify the enforceability of fire protection best practices document NFPA 850: Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations.

The project owner stated in the original application for certification (AFC) that the project would be built to the NFPA 850 standard and staff concurred with this assessment in the Final Staff Analysis (FSA). For power plants permitted by the Energy Commission, the Chief Building Official (CBO) is instructed through the Energy Commission's Delegate Chief Building Official manual to apply NFPA 850 during the construction process of the project. This measure has ensured that past projects have been built to the NFPA 850 standard. However, staff believes that because NFPA 850 is written as a set of "recommended" practices rather than "required" ones, the potential for confusion exists about whether conformance to NFPA 850 is indeed required. Staff therefore proposes Condition of Certification **WORKER SAFETY-7** which would require the project's compliance with NFPA 850, giving NFPA 850 the effectiveness and clear enforceability of a building code in its application to SEP. This proposed condition of certification would clarify for all stakeholders the responsibilities of the project owner as they relate to NFPA 850.

CONCLUSIONS AND RECOMMENDATIONS

Staff's proposed new Condition of Certification **WORKER SAFETY-7** would ensure that the project facility is built to comply with NFPA 850 recommendations by allowing the CBO to enforce all of the applicable provisions. Staff concludes that with the implementation of the existing conditions of certification and the newly proposed **WORKER SAFETY-7**, the proposed amendment would not have any adverse significant public impacts due to worker safety or fire protection practices.

PROPOSED CONDITIONS OF CERTIFICATION

Staff concludes that the existing conditions of certification along with the addition of **WORKER SAFETY-7** are adequate to ensure that there would be no unmitigated significant impacts. New text is shown in **<u>bold underline</u>**.

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 each has 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 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 first start-up of combustion turbine, the project owner shall submit to the CPM for approval a copy of the Project Operations and Maintenance Safety & Health Program. The project owner shall provide a letter from the City of Blythe Fire Department and the Riverside County Fire Department stating that each has reviewed and commented on the Operations Fire Protection and Prevention Plan and the Emergency Action Plan.

WORKER SAFETY-3 **DELETED; Commission Order 12-0425-3a**

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:

1. 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.
2. 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.
3. 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.
4. Inform the CPM within 24 hours of any temporary halt in construction or commissioning activities.
5. 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.
6. Verify that a safety program for the project that complies with CAL-OSHA & Federal regulations related to power plant projects has been implemented.
7. 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).
8. Verify that all construction and commissioning workers and supervisors receive adequate safety training.
9. Conduct accident and safety-related incident investigations, emergency response reports for injuries, and inform the CPM of all safety-related incidents.
10. Verify that all the plans identified in **WORKER SAFETY-1** are implemented.

The Safety Monitor shall be qualified regarding the following:

1. Safety issues related to equipment, pipelines, etc,
2. LORS applicable to workplace safety and worker protection
3. Workplace hazards typically associated with power production
4. 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.

WORKER SAFETY-6 The project owner shall develop and implement an enhanced Dust Control Plan that includes the requirements described in **AQ-SC3** and additionally requires:

i. site worker use of dust masks (NIOSH N-95 or better) whenever visible dust is present;

ii. implementation of methods equivalent to Rule 402 of the Kern County Air Pollution Control District (as amended Nov. 3, 2004); and

iii. implementation of enhanced dust control methods (increased frequency of watering, use of dust suppression chemicals, etc. consistent with **AQ-SC4**) immediately whenever visible dust comes from or onto the site or when PM10 measurements obtained when implementing ii (above) exceed 50 $\mu g/m^3$.

Verification: At least 60 days prior to the commencement of site mobilization, the enhanced Dust Control Plan shall be provided to the CPM for review and approval.

WORKER SAFETY-7 The project owner shall adhere to all applicable provisions of the latest version of NFPA 850: Recommended Practice For Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations. Project owner shall interpret and adhere to applicable NFPA 850 recommended provisions and actions stating "should" as "shall".

Verification: The project owner shall provide a letter to the CPM stating that the CBO has signed off on the design review of NFPA 850 compliance for all fire protection drawings and specifications prior to construction. Upon completion of the project, the project owner shall submit a second letter stating that the CBO has inspected the facility during construction through to completion and has verified NFPA 850 compliance.

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CBE2009a. Caithness Blythe Energy, Inc. Phase II Amendment (TN 53798). Docketed on 10/26/2009.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

CEC2012a. California Energy Commission. 2009 Petition to Amend – Staff Analysis (TN 60499). Docketed on 3/12/2012.

CEC2012b. California Energy Commission. Commission Order Approving 2009 Petition to Amend (TN 64945). Docketed on 4/26/2012.

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ENGINEERING ASSESSMENT

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SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
FACILITY DESIGN
Shahab Khoshmashrab

SUMMARY OF CONCLUSIONS

Similar to the conclusions in the 2005 Energy Commission Final Decision (2005 Decision) (CEC2005b) for the Blythe Energy Project Phase II (BEP II), the potential impacts of the proposed amendment would be less than significant. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Decision is necessary for **Facility Design**. The Committee may rely upon the analysis and conclusions of the 2005 Decision with regards to **Facility Design** and does not need to re-analyze them.

Staff concludes that the amendment project would comply with applicable engineering laws, ordinances, regulations, and standards (LORS). The conditions of certification, below, would ensure compliance with these LORS.

INTRODUCTION

Staff has reviewed the 2005 Decision approving the originally-licensed project and the 2012 Energy Commission Order (2012 Order) approving the 2009 amendment (CEC2012b). The 2009 amendment replaced the originally approved turbine technology (from the 2005 Decision) that was no longer available with newer Siemens Rapid-Start turbine technology. The 2009 amendment did not affect **Facility Design** as the replacement equipment was similar in scope and configuration and the 2012 Order did not adopt changes to **Facility Design**.

Staff has analyzed the proposed changes to the licensed BEP II, which include revising the two-on-one combined cycle power block to a one-on-one combined cycle power block that would incorporate a more efficient generating technology. The modified project would consist of one combustion turbine generator (CTG), one heat recovery steam generator (HRSG), and one steam turbine generator (STG), instead of the original project consisting of two CTGs, two HRSGs, and one STG. The petition also requests that the BEP II name be changed to Sonoran Energy Project (SEP). The following analysis evaluates the portions of the modified project that may affect the **Facility Design** analysis, findings, conclusions, and conditions of certification contained in the 2005 Decision.

SUMMARY OF THE DECISION

The 2005 Decision adopted the staff’s proposed conditions of certification that establish a design review and construction inspection process to ensure the project will be built in a manner to comply with applicable engineering LORS and ensure life safety. These conditions of certification specify the roles, qualifications, and responsibilities of engineering personnel overseeing project design and construction. They also require project design approval and construction inspection by the Energy Commission's delegate Chief Building Official (DCBO) to ensure compliance with those conditions of certification and the LORS. See the **Compliance Conditions** section for more detail on the role and responsibilities of the DCBO.

As noted above, the 2009 amendment did not affect **Facility Design** and the 2012 Order did not discuss this topic.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

No LORS applicable to the project have changed since the 2005 Decision was published except the change in the applicable version of the California Building Standards Code (CBSC), from 2001 to 2013. The proposed amendment would not trigger new LORS that may not have been applicable to the original project.

ANALYSIS

The modifications proposed in the amendment would reduce the number of the combustion turbines and heat recovery steam generators and their associated components and structures by replacing the two-on-one configuration with a one-on-one configuration. This does not substantially affect **Facility Design** because the same LORS and design review and inspection process apply to the SEP as those in the Decision and no material changes to the original **Facility Design** conditions of certification are needed.

However, the **Facility Design** conditions of certification contained in the decision refer to the 2001 edition of the CBSC. Since the issuance of the 2005 Decision, the CBSC has gone through some revisions and its current applicable version is the 2013 edition. Staff has updated the applicable version throughout those conditions of certification.

No further analysis is needed due to the following reasons:

- The changes in the amendment would not create new significant environmental impacts or substantial increases in the severity of previously identified significant impacts;
- The amendment does not propose substantial changes which would require major revisions of the **Facility Design** analysis contained in the Decision; and
- The circumstances under which the amended project would be undertaken would not require major revisions of the **Facility Design** analysis contained in the Decision.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the amendment project would comply with applicable engineering LORS. The proposed conditions of certification, below, would ensure compliance with these LORS.

PROPOSED CONDITIONS OF CERTIFICATION

The applicable version and section references of the CBSC have been updated. Deleted text is in ~~strikethrough~~ and new text is **<u>bold and underlined</u>**.

GEN-1 The project owner shall design, construct and inspect the project in accordance with the **<u>2013</u>**~~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.)

In the event that the initial engineering designs are submitted to the CBO when a successor to the **<u>2013</u>**~~2001~~ CBSC is in effect, the **<u>2013</u>**~~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 [**2013**~~2001~~ CBC, Section **110**~~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.

The project owner shall provide schedule updates in the Monthly Compliance Report.

GEN-3 The project owner shall make payments to the CBO for design review, plan 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 **2013**~~2001~~ CBC**, Section 109** ~~[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)].

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.]

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 [**2013**~~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. 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 when necessary, recommend changes in the design of the civil works facilities and changes in the construction procedures.

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 [**2013**~~2001~~ CBC, **Chapter 18, § 1803 and Chapter 18A, § 1803A Geotechnical Investigations** ~~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 **2013**~~2001~~ CBC, **Chapter 17, § 1704, Special Inspection** ~~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 [**2013**~~2001~~ CBC, section **115**~~104.2.4~~, Stop **Work** Orders].

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 **2013**~~2001~~ CBC, ~~Appendix Chapter 33;~~ Sections **1704 and 1704A**~~3317, Grading Inspections~~ (depending on the site conditions, this may be the responsibility of either the soils engineer or engineering geologist or both).

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.

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 **2013**~~2001~~ CBC, Chapter 17 [**Section 1704, Special Inspections; Chapter 17A, Section 1704A, Special Inspections; and Appendix Chapter 1, Section 110, Inspections** ~~Section 1701, Special Inspections; Section 1701.5, Type of Work (requiring special inspection)]; and Section 106.3.5, Inspection and observation program~~. 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 [**2013**~~2001~~ CBC, Chapter 17, **§ 1704.2.4~~1.2~~, Report Requirements** ~~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 onsite 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 [**<u>2013</u>**~~2001~~ CBC, **<u>Chapter 17, § 1704.2.4, Report Requirements</u>** ~~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 [**2013**~~2001~~ CBC, Section **1.8.4.3.1**~~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 **2013**~~2001~~ CBC [**Chapter 18, § 1803.6 Reporting, and § 1803, Geotechnical Investigation**~~ 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 [**2013**~~2001~~ CBC, **Appendix Chapter 1, § 115**~~Section 104.2.4~~, Stop **Work** 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 **<u>2013</u>**~~2001~~ CBC, Chapter 1, Section **<u>110</u>**~~108~~, Inspections; Chapter 17, Section **<u>1704</u>**~~1701.6~~, **<u>Special Inspections</u>** ~~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 [**<u>2013</u>**~~2001~~ CBC, **<u>Chapter 17, § 1704.2.4, Report Requirements</u>** ~~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 [**<u>2013</u>**~~2001~~ CBC, **<u>Chapter 17, § 1703.2, Written Approval</u>** ~~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), 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:

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 [**2013**~~2001~~ CBC, **104.1, Duties and Powers of Building Official, 105, Permits** ~~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 [**2013**~~2001~~ CBC, **Appendix Chapter 1, § 107.5 Retention of Construction Documents** ~~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 [**2013**~~2001~~ CBC, **Appendix Chapter 1, § 107.3.4**~~**106.3.4**~~**, Design Professional in Responsible Charge** ~~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 [**2013**~~2001~~ CBC, **Appendix Chapter 1, § 107.3.4, Design Professional in Responsible Charge** ~~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 major structures or components, 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 **2013**~~2001~~ CBC, **Chapter 17, section 1704, Special Inspections and Structural Observations** ~~Chapter 17, Section 1701, Special Inspections; Section 1701.5, Type of Work (requiring special inspection); Section 1702, Structural Observation and Section 1703, Nondestructive Testing~~.

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 [**2013**~~2001~~ CBC, **Chapter 17, § 1704.2.4, Report Requirements** ~~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.

Verification: 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 **2013**~~2001~~ CBC, **Appendix Chapter 1, § 107, Submittal Documents; 2013 California Administrative Code, § 4-215, Changes in Approved Drawings and Specifications** ~~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 **H-2 Occupancy Category of the 2013 CBC** ~~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.

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 [**2013**~~2001~~ CBC, **Appendix Chapter 1, § 107, Submittal Documents; § 110, Inspections, § 105, Permits; 2013 California Plumbing Code, § 301, Materials** ~~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 [**2013 CBC, Appendix Chapter 1, § 107.3.4, Design Professional in Responsible Charge** ~~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 [**2013**~~2001~~ CBC, Section **103.3**~~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, 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 [**2013**~~2001~~ CBC, Section **110**~~108.3~~, Inspections~~ 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 to the applicable LORS [**2013**~~2001~~ CBC, **§ 110.3.7, Energy Efficiency Inspections; § 107.3.4, Design Professionals in Responsible Charge** ~~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 **2013**~~2001~~, Section **107**~~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 [**2013**~~2001~~ CBC, Section **§ 1704** ~~108.4, Approval Required, and Section 108.3, Inspection Requests~~].

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

ASE2015a – AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CEC2012b. California Energy Commission. 2012 Commission Order Approving 2009 Petition to Amend (TN 64945). Docketed on 4/26/2012.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

SONORAN ENERGY PROJECT (02-AFC-1C)

Request to Amend Final Commission Decision
GEOLOGY & PALEONTOLOGY
Mike Conway

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Sonoran Energy Project (SEP) does not seek to modify the existing **Geology & Paleontology** Conditions of Certification. Similar to the conclusions in the project's licensed Blythe Energy Project Phase II (BEP II) 2005 California Energy Commission (Energy Commission) Final Decision (2005 Decision), the potential impacts of the proposed PTA would be less than significant. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Decision is necessary for Geology & Paleontology. The Committee may rely upon the environmental analysis and conclusions of the 2005 Decision with regards to Geology & Paleontology and does not need to re-analyze them. However, staff is proposing minor changes to update the conditions of certifications in this section for the purpose of making the existing requirements more clear – staff does not believe the proposed conditions impose any new requirements on the owner.

INTRODUCTION

In this section, Energy Commission staff discusses potential impacts of the proposed amendment in relation to geologic hazards, and geologic (including mineralogic), and paleontologic resources. (See the 2005 Decision for the project at http://www.energy.ca.gov/2005publications/CEC-800-2005-005/CEC-800-2005-005-CMF.PDF)

SUMMARY OF THE DECISION

The 2005 Decision for the project did not find any immitigable impacts to geologic or paleontological resources. The 2005 Decision states that no known mineralogical or paleontological resources exist at the project site, but required Conditions of Certifications of Certification **PAL-1** through **PAL-7** to account for the potential recovery of paleontological resources. The Decision also required the owner to prepare an Engineering Geology Report to characterize the geologic conditions on site.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

New LORS that would apply to Sonoran project are discussed below.

Applicable LOR	Description
State	
California Building Code (2013)	The California Building Code (CBC 2013) includes a series of standards that are used in project investigation, design, and construction (including seismicity, grading and erosion control). The CBC has adopted provisions in the International Building Code (IBC, 2012).

Applicable LOR	Description
Standards	
Society for Vertebrate Paleontology (SVP), 2010	The “Measures for Assessment and Mitigation of Adverse Impacts to Non-Renewable Paleontological Resources: Standard Procedures” is a set of procedures and standards for assessing and mitigating impacts to vertebrate paleontological resources developed by the SVP, a national organization of professional scientists. The measures were adopted in October 1995, and revised in 2010 following adoption of the Paleontological Resources Preservation Act (PRPA) of 2009.
Bureau of Land Management (BLM) Instructional Memorandum 2008-009	Provides up-to-date methodologies for assessing paleontological sensitivity and management guidelines for paleontological resources on lands managed by the Bureau of Land Management. While not required on non-BLM lands, the methodologies are useful for all paleontological studies, regardless of land ownership.

ENVIRONMENTAL IMPACT ANALYSIS

Since the subsurface conditions and associated geologic hazards at the proposed site are expected to be similar to those previously analyzed; potential geologic hazards and the thresholds for significance are essentially the same as documented in the 2005 Decision. In addition, there are no significant geologic resources present in the project area, therefore there is no potential to impact those resources. However, staff has added a new condition for protection from geologic hazards, **GEO-1**, that requires submittal of geotechnical analysis with final grading plans. Furthermore, there is still the potential to encounter paleontological resources during construction of the project.

CONSTRUCTION IMPACTS AND MITIGATION

The applicant’s consultant conducted a paleontologic resources field survey and a sensitivity analysis for the Blythe Energy Project (BEP) 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 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, the proposed BEP II site has a high potential to contain significant paleontologic resources (CEC, 2005).

The geologic hazards present at the Sonoran site are essentially the same as those considered in the 2005 Decision. These potential hazards can be effectively mitigated through facility design as required by the California Building Code (2013) and Condition of Certification **GEO-1**. Condition of Certification **GEO-1** is a new condition (since 2005) that requires a soils engineering report in accordance with current standards. This condition of certification compliments and reinforces Conditions of Certification **GEN-1, GEN-5**, and **CIVIL-1** in the **FACILITY DESIGN** section. This condition will ensure that the project will be designed using current standards to protect public safety from potential impacts related to geologic hazards.

Since construction of the proposed project will include significant amounts of grading, foundation excavation, and utility trenching, staff considers the probability that paleontological resources will be encountered during such activities to be high when native materials are encountered, based on SVP assessment criteria. Conditions of Certification **PAL-1** through **PAL-8** are designed to mitigate any paleontological resource impacts, as discussed above, to a less than significant level. Staff has modified the original conditions of certification for paleontological resources and added two new conditions of certification which address the same potential impacts as the originals but further clarify, update, and ensure accurate planning, training, monitoring, and reporting.

CUMULATIVE IMPACTS AND MITIGATION

There are no changes to the cumulative impacts section of the 2005 Decision caused by the proposed amendment changes. As a result, no additional mitigation is considered necessary.

CONCLUSIONS AND RECOMMENDATIONS

The Conditions of Certification included in this section were from the original conditions issued with the BEP II (02-AFC-01) power plant license in 2005. There are now eight Paleontology conditions instead of the original seven; however their content remains essentially unchanged.

General Conditions of Certification with respect to engineering geology are proposed under Conditions of Certification **GEN-1, GEN-5**, and **CIVIL-1** in the **FACILITY DESIGN** section and in **GEO-1** of this section. **GEO-1** has been added to ensure the project is designed using current building standards for geologic hazards and to provide public safety.

Proposed paleontological Conditions of Certification follow in **PAL-1** through **PAL-8**. It is staff's opinion that the likelihood of encountering paleontologic resources could be high in areas where native Pleistocene or Eocene age deposits occur in excavations. Staff would consider reducing monitoring intensity, at the recommendation of the project Paleontological Resources Specialist (PRS), following examination of sufficient, representative excavations that fully describe site stratigraphy.

PROPOSED CONDITIONS OF CERTIFICATION

GEO-1 A Soils Engineering Report as required by Section 1803 of the California Building Code (CBC 2013) shall specifically include laboratory test data, associated geotechnical engineering analyses, and a thorough discussion of seismicity; liquefaction; dynamic compaction; compressible soils; corrosive soils; and tsunami. In accordance with CBC 2013, the report should also include recommendations for ground improvement and/or foundation systems necessary to mitigate these potential geologic hazards, if present.

Verification: The project owner shall include in the application for a grading permit a copy of the Soils Engineering Report which addresses the potential for strong seismic shaking; liquefaction; dynamic compaction; settlement due to compressible soils; corrosive soils, and tsunami, and a summary of how the results of the analyses were incorporated into the project foundation and grading plan design for review and comment by the Chief Building Official (CBO). A copy of the Soils Engineering Report, application for grading permit, and any comments by the CBO are to be provided to the compliance project manager (CPM) at least 30 days prior to grading.

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~~ **Qualified Professional Paleontologist as defined in the Standard Procedures for the Assessment and Mitigation of Adverse Impacts to Paleontological Resources by the Society of Vertebrate Paleontology (SVP 2010).** The experience of the PRS shall include the following:

1. Institutional affiliations, appropriate credentials and college degree;
2. ability to recognize and collect fossils in the field;

3. local geological and biostratigraphic expertise;
4. proficiency in identifying vertebrate and invertebrate fossils and;
5. at least three years of paleontological resource mitigation and field experience in California, and at least one year of experience leading paleontological resource mitigation and field activities.

The project owner shall ensure that the PRS obtains qualified paleontological resource monitors to oversee and evaluate project operations as he or she deems necessary.

PRMs shall have the equivalent **or combination** of the following qualifications **approved by the CPM:**

- 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 of 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.

The project owner shall keep resumes on file for qualified paleontological resources monitors (PRMs). If a PRM is replaced, the resume of the replacement PRM shall also be provided to the CPM for review and approval.

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~~ **PRMs for the project. The letter shall state, that the identified PRM's meet the minimum qualifications for paleontological resource monitoring as required by this condition of certification.** If additional ~~monitors~~ **PRMs** 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. ~~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.~~

(3) Prior to any change of the 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.~~ **at a scale between 1 inch = 40 feet and 1 inch = 100 feet.** If the footprint of the power plant or linear ~~facility~~ **facilities** change~~s~~, 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~~ **Before work commences** on affected phases, the project owner shall notify the PRS and CPM of any construction phase scheduling changes.

At a minimum, the project owner shall ensure that the PRS or PRM consults weekly with the project superintendent or construction field manager to confirm area(s) to be worked 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. ~~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~~.

(3) If there are changes to the scheduling of the construction phases, the project owner shall submit a letter to the CPM within five 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.~~ **and submits the PRMMP to the CPM for review and approval.** 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~~ **The PRMMP** shall be used as a basis for discussion in the event that on-site decisions or changes are proposed. Copies of the PRMMP shall **include all updates and** 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~~ **2010**) 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. **An explanation of why sampling is needed, a description of the sampling methodology, and how much sampling is expected to take place in which geologic units. Include descriptions of different sampling procedures that shall be used for fine-grained and coarse-grained units;**
5. A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed schedule for the monitoring and sampling;
6. A discussion of ~~the~~ procedures to be followed**: (a)** in the event of a significant fossil discovery, **(b)** ~~halting~~ **stopping** construction, **(c)** resuming construction, and **(d)** how notifications will be performed;
7. A discussion of equipment and supplies necessary for collection of fossil materials and any specialized equipment needed to prepare, remove, load, transport, and analyze large-sized fossils or extensive fossil deposits;
8. Procedures for inventory, preparation, and delivery for curation into a retrievable storage collection in a public repository or museum, which meets the Society of Vertebrate Paleontology standards and requirements for the curation of paleontological resources;
9. 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
10. A copy of the paleontological **resources** 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 **for review and approval**. **Approval of the PRMMP by the CPM shall occur prior to any ground disturbance.** 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 **the project owner and the PRS shall prepare a CPM-approved Worker Environmental Awareness Program (WEAP).** ~~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:~~
The WEAP shall address the possibility of encountering paleontological resources in the field, the sensitivity and importance of these resources, and legal obligations to preserve and protect those resources. The purpose of the WEAP is to train project workers to recognize paleontologic resources and identify procedures they should follow to ensure there are no impacts to sensitive paleontologic resources. The WEAP 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.

8. **The Project Owner shall also submit the training script and, if the project owner is planning to use a video for training, a copy of the training video with the set of reporting procedures for workers to follow that will be used to present the WEAP and qualify workers to conduct ground disturbing activities that could impact paleontologic resources.**

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.~~ **to the CPM for review and comment the draft WEAP, including the brochure and sticker. The submittal shall also include a draft training script and, if the project owner is planning to use a video for training, a copy of the training video with the set of reporting procedures for workers to follow.**

(2) At least ~~30~~ **15** 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.~~ **to the CPM for approval the final WEAP and training script.**

~~If the project owner requests an alternate paleontological trainer, the project owner shall submit the resume and qualifications of the trainer to the CPM for review and approval prior to installation of the alternate trainer. Alternate trainers shall not conduct training prior to CPM authorization.~~

~~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 No worker shall excavate or perform any ground disturbance activity prior to receiving CPM-approved WEAP training by the PRS, unless specifically approved by the CPM.

Prior to project kick-off and ground disturbance the following workers shall be WEAP trained by the PRS in-person: project managers, construction supervisors, foremen, and all general workers involved with or who operate ground-disturbing equipment or tools. Following project kick-off a WEAP certification of completion form shall be used to document who has received the required training.

Verification: In the Monthly Compliance Report (MCR), the project owner shall provide copies of the WEAP certification of completion forms with the names of those trained and the trainer or type of training (in-person and/or video) offered that month. An example of a suitable WEAP certification complete form is provided below. The MCR shall also include a running total of all persons who have completed the training to date.

If the project owner requests an alternate paleontological WEAP trainer, the resume and qualifications of the trainer shall be submitted to the CPM for review and approval prior to installation of an alternate trainer. Alternate trainers shall not conduct WEAP training prior to CPM authorization.

~~PAL-5~~PAL-6 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 previously undisturbed materials 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~~ **and other activities.** 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-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 **shall be** 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.~~ **the PRS' description of sensitivity and significance of those resources; and indicate if and how fossil material was curated in accordance with PAL-8;**

Verification: Within (90) days after completion of ground disturbing activities, including landscaping, the project owner shall submit the ~~Paleontological Resources Report~~ **PRR** under confidential cover to the CPM.

PAL-8 The project owner, through the designated PRS, shall ensure that all components of the PRMMP are adequately performed, including collection of fossil material, preparation of fossil material for analysis, analysis of fossils, identification and inventory of fossils, preparation of fossils for curation, and delivery for curation of all significant paleontological resource materials encountered and collected during project construction. The project owner shall pay all curation fees charged by the museum for fossil material collected and curated as a result of paleontological mitigation. The project owner shall also provide the curator with documentation showing the project owner

irrevocably and unconditionally donates, gives, and assigns permanent, absolute, and unconditional ownership of the fossil material.

Verification: Within 60 days after the submittal of the PRR, the project owner shall submit documentation to the CPM showing fees have been paid for curation and the owner relinquishes control and ownership of all fossil material.

REFERENCES

ASE2015a - AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CEC 2005 - Blythe II Energy Project Final Commission Decision. Accessed online on November 24, 2015 at: http://www.energy.ca.gov/2005publications/CEC-800-2005-005/CEC-800-2005-005-CMF.PDF.

SVP 2010 - Society of Vertebrate Paleontology, Impact Mitigation Guidelines Revision Committee Standard Procedures for the Assessment and Mitigation of Adverse Impacts to Paleontological Resources, 2010.

SONORAN ENERGY PROJECT (02-AFC-01C)

Petition to Amend Final Commission Decision
POWER PLANT EFFICIENCY
Edward Brady

SUMMARY OF CONCLUSIONS

The Sonoran Energy Project's (SEP) thermal efficiency would compare favorably with the efficiency of similar combined cycle electric generation power plants that provide rapid-response capability, including the Blythe Energy Project Phase II (BEP II). The source of natural gas fuel for the amended project would be reliable.

Similar to the conclusions in the 2005 Energy Commission Final Decision (2005 Decision) (CEC2005b) for the BEP II, the amended project would create no significant impacts related to power plant efficiency. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Decision is necessary for **Power Plant Efficiency**. The Committee may rely upon the analysis and conclusions of the 2005 Decision with regards to **Power Plant Efficiency** and does not need to re-analyze them.

INTRODUCTION

Staff has reviewed the 2005 Decision approving the originally-licensed project and the 2012 Energy Commission Order (2012 Order) approving the 2009 amendment (CEC2012b). The 2009 amendment replaced the originally approved turbine technology (from the 2005 Decision) that was no longer available, with newer Siemens rapid-response (fast response flexible ramping capability) turbine technology. The 2009 amendment did not affect power plant efficiency because the replacement equipment was similar in thermal efficiency and configuration. Consequently, the 2012 Order did not adopt changes to power plant efficiency.

Staff has analyzed the proposed changes to the licensed Blythe Energy Project Phase II (BEP II), which include revising the two-on-one combined cycle power block to a one-on-one combined cycle power block that would incorporate a more efficient generating technology. The modified project would consist of one combustion turbine generator (CTG), one heat recovery steam generator (HRSG), and one steam turbine generator (STG), instead of the original project consisting of two CTGs, two HRSGs, and one STG. The petition also requests that the BEP II name be changed to Sonoran Energy Project (SEP). The following analysis evaluates the portions of the modified project that may affect the **Power Plant Efficiency** analysis, findings, conclusions, and conditions of certification contained in the 2005 Decision.

SUMMARY OF THE DECISION

The 2005 Decision found that the BEP II's maximum nominal efficiency of 58 percent for its two-on-one rapid-response combined cycle system was comparable to the efficiency of similar combined cycle power plants with rapid-response capability. The 2005 Decision also found the source of natural gas fuel for the project to be reliable.

As noted above, the 2009 amendment did not affect **Power Plant Efficiency** and the 2012 Order did not discuss this topic.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

No federal, state, or local laws, ordinances, regulations, or standards (LORS) apply to power plant efficiency.

STAFF ANALYSIS

The proposed amendment (ASE2015a) requests substitution of the approved rapid-response, two-on-one combined cycle configuration using two Siemens SCC6-5000F CTGs (from the Siemens F-class technology) with a rapid-response, one-on-one combined cycle configuration using one General Electric (GE) 7HA.02 CTG (from the GE 7H-class technology). The GE 7H series is the larger, next generation version of the GE 7F series. The GE 7F technology is parallel to the Siemens 5000F technology and results in similar efficiencies. The SEP's maximum combined cycle efficiency using the GE 7HA.02 can be expected to reach as high as 60 percent nominally. Compared to the 58 percent maximum nominal efficiency of the BEP II, this is an improvement. This higher efficiency is achieved through the GE 7H's higher pressure ratio and firing temperature than the GE 7F or Siemens 5000F, made possible by the use of single-crystal turbine blades and improved blade aerodynamics.

The SEP's higher efficiency would marginally reduce the quantities of natural gas that would be consumed by the project on a per-megawatt basis compared to the BEP II. Also, the SEP's expected efficiency compares favorably with existing power plants.

Consistent with the BEP II, natural gas fuel would be delivered to the SEP via an existing Southern California Gas (SoCalGas) 16-inch-diameter pipeline (ASE2015a, § 2.5.3). SoCalGas' natural gas comes from resources in the Southwest, Canada, and the Rocky Mountains. This represents a resource of considerable capacity and offers access to adequate supplies of natural gas. Thus, the source of natural gas fuel for the amended project would be reliable.

No further analysis is needed due to the following reasons:

- The changes in the amendment would not create new significant environmental impacts or substantial increases in the severity of previously identified significant impacts;

- The amendment does not propose substantial changes which would require major revisions of the **Power Plant Efficiency** analysis contained in the 2005 Decision; and
- The circumstances under which the amended project would be undertaken would not require major revisions of the **Power Plant Efficiency** analysis contained in the 2005 Decision.

CONCLUSIONS

Staff concludes that similar to the licensed project, the amended project would create no significant impacts related to power plant efficiency. SEP's thermal efficiency would compare favorably with the efficiency of similar combined cycle electric generation power plants that provide rapid-response capability. The source of natural gas fuel for the amended project would be reliable.

CONDITIONS OF CERTIFICATION

The 2005 Decision included no conditions of certification for **Power Plant Efficiency** and staff believes no such conditions are warranted by the proposed amendment, and none are proposed.

REFERENCES

ASE2015a – AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CEC2012b. California Energy Commission. 2012 Commission Order Approving 2009 Petition to Amend (TN 64945). Docketed on 4/26/2012.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

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SONORAN ENERGY PROJECT (02-AFC-01C)

Petition to Amend Final Commission Decision
POWER PLANT RELIABILITY
Edward Brady

SUMMARY OF CONCLUSIONS

Similar to the conclusions in the 2005 Energy Commission Final Decision (2005 Decision) (CEC2005b) for the Blythe Energy Project Phase II (BEP II), the Sonoran Energy Project (SEP) would be built and would operate in a manner consistent with industry norms for reliable operation and would maintain a level of reliability which equals or exceeds reliability of similar operating electric generation facilities. Also similar to the BEP II, the amended project would create no significant impacts related to power plant reliability. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Decision is necessary for **Power Plant Reliability**. The Committee may rely upon the analysis and conclusions of the 2005 Decision with regards to **Power Plant Reliability** and does not need to re-analyze them.

INTRODUCTION

Staff has reviewed the 2005 Decision approving the originally-licensed project and the 2012 Energy Commission Order (2012 Order) approving the 2009 amendment (CEC2012b). The 2009 amendment replaced the originally approved turbine technology (from the 2005 Decision) that was no longer available, with newer Siemens Rapid-Start turbine technology. The 2009 amendment did not affect **Power Plant Reliability** as the replacement equipment was similar in scope and configuration and the 2012 Order did not address power plant reliability.

Staff has analyzed the proposed changes to the licensed BEP II, which include revising the two-on-one combined cycle power block to a one-on-one combined cycle power block that would incorporate a more efficient generating technology. The modified project would consist of one combustion turbine generator (CTG), one heat recovery steam generator (HRSG), and one steam turbine generator (STG), instead of the original project consisting of two CTGs, two HRSGs, and one STG. The petition also requests that the BEP II name be changed to Sonoran Energy Project. The following analysis evaluates the portions of the modified project that may affect the **Power Plant Reliability** analysis, findings, conclusions, and conditions of certification contained in the 2005 Decision.

SUMMARY OF THE DECISION

The 2005 Decision found that the BEP II's plant maintenance program and redundant equipment list, the sources of the project's natural gas fuel and cooling and potable water supplies, and the project's ability to withstand natural disasters by complying with the **Facility Design** conditions of certification will result in an adequate level of reliability; a level of reliability which equals or exceeds reliability of similar operating electric generation facilities.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

No federal, state, or local/county laws, ordinances, regulations, or standards (LORS) apply to power plant reliability.

STAFF ANALYSIS

Changing the project from a two-on-one combined cycle configuration to a one-on-one combined cycle configuration would eliminate one of the CTGs. Typically such an additional CTG provides inherent reliability. Failure of a non-redundant component of one CTG should not cause the other CTG to fail, thus allowing the plant to continue to generate electricity, though at reduced output. However, in a one-on-one configuration, the lack of this benefit can be overcome by providing adequate component redundancy. The proposed amendment provides a list of redundant equipment (ASE2015a, Table 2-7). It includes a series of 100-percent-capacity redundant pumps, air compressors, heat exchangers, reverse osmosis units, etc. It also describes that the STG steam bypass system would allow the CTG/HRSG train to operate at its base load capacity with the STG out of service. Staff believes these equipment redundancies and this bypass system would enable the SEP to demonstrate a similar level of plant availability and reliability as the BEP II.

The proposed amendment also describes the SEP's plant maintenance program and the sources of natural gas fuel and cooling and potable water supplies (ASE2015a, § 2.5), which are the same as the BEP II. Also, similar to the BEP II, the SEP would be able to withstand natural disasters by complying with the conditions of certification described in the **Facility Design** section of this analysis. These conditions of certification would ensure the project is built in compliance with the latest applicable engineering and building codes.

No further analysis is needed due to the following reasons:

- The changes in the amendment would not create new significant environmental impacts or substantial increases in the severity of previously identified significant impacts;
- The amendment does not propose substantial changes which would require major revisions of the **Power Plant Reliability** analysis contained in the 2005 Decision; and
- The circumstances under which the amended project would be undertaken would not require major revisions of the **Power Plant Reliability** analysis contained in the 2005 Decision.

CONCLUSIONS

Staff concludes that similar to the BEP II, the SEP would be built and would operate in a manner consistent with industry norms for reliable operation and would maintain a level of reliability which equals or exceeds reliability of similar operating electric generation facilities.

CONDITIONS OF CERTIFICATION

The 2005 Decision included no conditions of certification for **Power Plant Reliability** and staff believes no such conditions are warranted by the proposed amendment, and none are proposed.

REFERENCES

ASE2015a – AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CEC2012b. California Energy Commission. 2012 Commission Order Approving 2009 Petition to Amend (TN 64945). Docketed on 4/26/2012.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

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SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
TRANSMISSION SYSTEM ENGINEERING
Ajoy Guha, P.E. and Mark Hesters

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Sonoran Energy Project (SEP) proposes to modify the project which will necessitate modification to existing **Transmission System Engineering** Conditions of Certification. Currently, staff requires more information on proposed changes to the transmission interconnection and potential impacts on existing transmission networks. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff is unable to conclude that no supplementation to the Blythe Energy Project 2005 Decision (2005 Decision) is necessary for **Transmission System Engineering**.

Staff recommends revising Conditions of Certifications **TSE-1** through **TSE-8**, as amended, to ensure that the proposed facilities are designed, built and operated in accordance with good utility practices and applicable laws, ordinances, regulations and standards (LORS). Staff may include further changes in the Final Staff Assessment (FSA) depending on the information provided in the Western Facilities Study and an Affected System Impact Study (SIS) by Southern California Edison (SCE) or the results of consultations with SCE and the Applicant.

The SEP PTA would completely change the proposed transmission interconnection. The previous decision approved a 500 kV interconnection to the 500 kV Keim substation and the Southern California Edison (SCE) 500 kilovolt (kV) System. The proposed amendment would connect the SEP at 161 kV to the Western Area Power Administration's (Western) system.

1. The SIS indicated that there could be downstream project impacts that may require environmental analysis in the Energy Commission staff assessment. These impacts cannot be identified without the Western Detailed Facilities Study, and the results of an Affected SIS or a consultation with SCE, which the project owner has agreed to provide when they are available.
2. Staff has updated the proposed conditions of certification to include standards required for an interconnection that affects the Western and SCE systems.

At this time, staff is unable to determine whether the proposed changes would comply with applicable LORS. The project owner has not provided some of the information about the proposed generator-tie line and the termination facilities at the Western Buck Blvd 161 kV Switching station, and the impacts on the Western and SCE systems are still unknown.

INTRODUCTION

Staff describes the proposed amended transmission interconnection facilities in detail later in this section. The prosed project would no longer connect directly to the SCE system, but may still affect SCE's facilities. Because of these potential impacts, SCE and the California Independent System Operator (ISO) standards would apply to any affected facilities and SCE may conduct an Affected Systems Study.

The new interconnecting utility would be Western, and as such Western is responsible for ensuring that the interconnection and operation of the Sonoran project would not cause its transmission system to be out of compliance with regional and national reliability standards. Western has completed a System Impact Study for the SEP. Western will require completion of a Detailed Facilities Study and the execution of an Interconnection Agreement before SEP will be allowed to connect to the Buck Boulevard substation.

SUMMARY OF THE DECISION

The 2005 Decision as it related to Transmission System Engineering is not relevant to the proposed interconnection as the proposed interconnection is completely different.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

In addition to the LORS in the original analysis, the proposed interconnection to the Western's Desert Southwest Region (Western DSWR) would require compliance with Western's "General Requirements for Interconnection," (September 1999) which provides Western's general minimum requirements including technical, environmental and contractual requirements for interconnection, additions and modifications to Western's transmission facilities.

ENGINEERING ANALYSIS

Staff is providing a discussion of the proposed interconnection to the Western transmission system. Analysis of the potential impacts to the Western and SCE transmission systems will be included in the Final Staff Assessment (FSA) once staff has received Western Facilities Study, and an Affected SIS by SCE or the results of consultations between the project owner and SCE.

AMENDED PROJECT DESCRIPTION

The Sonoran Energy project (SEP) site is a 76-acre parcel located within the City of Blythe, in eastern Riverside County, California. The SEP is a natural gas-fired combined-cycle plant with a total 553 MW net generating capacity. The power block will consist of a combustion turbine (CT), General Electric (GE) Frame 7HA.02, rated 333 MW and a steam turbine (ST), GE Frame D652 rated 220 MW along with a single GE

Generator of 596.5 MW nominal capacity, all three machines on a single shaft configuration with a 553 MW net plant generating capacity.

SWITCHYARD AND INTERCONNECTION FACILITIES

The 596.5 MW, 23.5 KV generator would be connected through 16,000-Amperes segregated 3-phase bus duct and a 16,000 Amperes, 24 kV circuit breaker to the low side of a 500/550/600 MVA, 230/161/23.5 kV generator step-up transformer (GSU). The 161 kV high side of the GSU transformer would be connected through short overhead conductors to a 3000 Ampere, 170 kV Breaker with an associated 3,000 amperes disconnect switch.

The generator-tie line would be terminated at one end at the 3,000 Ampere, 170 kV breaker at the SEP switchyard (Ref. Figure DR46-1) and the other end of the 161 kV gen tie line would be terminated at the Western Buck Boulevard 161 kV switching station. The interconnection at the Buck Boulevard substation would require a new 161kV switch bay which would be built between the East and West 161 kV buses in a double bus and double breaker configuration with two breakers and two associated disconnect switches for each 161 kV breaker (ASE2015g). The conductor size, type and ampere rating of the generator-tie line are not yet specified.

The 1,132-ft. long 161 kV gen tie line will have average 150-ft wide Right-of Way (ROW) thru a public road and private road and properties of the SEP switchyard and Buck Blvd. 161 kV switchyards.

Staff is unable to make a LORS determination for the SEP as the specifics of the generator-tie line and terminal facilities at the Western Buck Blvd. Switching Station have not been provided. The project owner has indicated that this information will be provided in the Western Facilities Study.

Staff tentatively proposes changes to Conditions of Certifications **TSE-1** through **TSE-8**, as amended, to insure that the proposed facilities are designed, built and operated in accordance with good utility practices and applicable LORS. Staff may include further changes in the FSA depending on the information provided in the Western Facilities Study and an Affected SIS by SCE or the results of consultations with SCE and the Applicant.

CONCLUSIONS AND RECOMMENDATIONS

Staff requires information to complete its analysis of the proposed transmission interconnection.

1. Staff is unable to make a LORS determination for the SEP as the specifics of the generator-tie line and the terminal facilities at the Western Buck Blvd. Switching Station have not been provided. The project owner has indicated that this information will be provided in the Western Facilities Study.

2. The SIS indicated there could be downstream Project Impacts that may require environmental analysis in the Energy Commission Staff assessment. Staff is unable to analyze potential downstream transmission impacts without the Western Detailed Facilities Study, and the Affected System Impact Study by SCE and the results of discussions with SCE on potential impacts to their transmission system.
3. Staff has provided its proposed conditions of certification for the change; however, more changes may be required during the review of future documents.

PROPOSED CONDITIONS OF CERTIFICATION

The Transmission System Engineering conditions of certification for the SEP are listed below. Staff is proposing minor administrative revisions to existing Conditions of Certification **TSE-1**, **TSE-2**, **TSE-3**, **TSE-4, TSE-5**, **TSE-7** and **TSE-8** to reflect the current proposed interconnection. Staff is proposing the deletion of Condition of Certification **TSE-6** has been incorporated into the other conditions, thus staff is proposing the deletion of this condition. Staff is proposing the deletion of **TSE-9** because connection to the Desert Southwest Transmission System is no longer part of the proposed project. Additions are shown in **<u>bold underlined</u>** text and deletions are shown in ~~strikethrough~~.

TSE-1 The project owner shall furnish to the CPM and to the CBO a schedule of transmission facility design submittals, a Master Drawing List, a Master Specifications List, and a Major Equipment and Structure List ~~for the BEP II transmission facilities to the first point of interconnection at the Buck Blvd Substation~~. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide designated packages to the CPM when requested. This condition applies only to the power plant Integration Switchyard, **<u>generator</u>** ~~and transmission~~ tie line **<u>and its termination</u>**.

<u>Verification</u>: At least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of construction of any transmission facility, the project owner shall submit the schedule, ~~an updated~~ a Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major equipment in **Table 1: Major Equipment List** ~~(~~below). Additions and deletions shall be made to the table only with CPM and CBO approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Equipment List
Breakers
Step-up Transformer
Switchyard

Busses **<u>And Bus Ducts</u>**
Surge Arrestors
Disconnects and Wave-traps
Take off facilities
Electrical Control Building
Switchyard Control Building
Transmission Pole/Tower
Insulators and Conductors
Grounding System

TSE-2 Prior to the start of construction ~~of the power plant Integration Switchyard or transmission tie line to the Buck Boulevard Substation~~, the project owner shall assign an electrical engineer and at least one of each of the following to the project:

A) a civil engineer;

B) a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering;

C) a design engineer, who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; or

D) a mechanical engineer. (Business and Professions Code Sections 6704 et seq., require state registration to practice as a civil engineer or structural engineer in California.)

The tasks performed by the civil, mechanical, electrical or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g., proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer. The civil, geotechnical or civil and design engineer assigned in conformance with Facility Design condition **GEN-5**, may be responsible for design and review of the TSE facilities.

The project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all engineers assigned to the project. If any one of the designated engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer. This engineer shall be authorized to halt earthwork and to require changes; if site conditions are unsafe or do not conform to predicted conditions used as a basis for design of earthwork or foundations.

The electrical engineer shall:

1. Be responsible for the electrical design of the power plant switchyard, outlet and termination facilities; and
2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

Verification: At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading ~~for transmission related facilities to the first point of interconnection at Buck Boulevard~~, the project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all the responsible engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

TSE-3 If any discrepancy in design and/or construction is discovered in any ~~transmission facility~~ engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend corrective action. (1998 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall become a controlled document and shall be submitted to the CBO for review and approval and shall reference this condition of certification.

Verification: The project owner shall submit a copy of the CBO's approval or disapproval of any corrective action taken to resolve a discrepancy to the CPM within 15 days of receipt. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action required to obtain the CBO's approval.

TSE-4 For the power plant Integration switchyard, outlet line and termination, the project owner shall not begin any increment of construction until plans for that increment have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. The following activities shall be reported in the Monthly Compliance Report:

a) receipt or delay of major electrical equipment;

b) testing or energizing of major electrical equipment; and

c) the number of electrical drawings approved, submitted for approval, and still to be submitted.

Verification: At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of each increment of construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications and calculations for equipment and systems of the power plant **integration** switchyard, outlet line and termination, including a copy of the signed and stamped statement from the responsible electrical engineer attesting to compliance with the applicable LORS, and send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

TSE-5 ~~The project owner shall ensure that the design, construction and operation of the proposed power plant Integration Switchyard and transmission tie line facilities to the Buck Boulevard Substation will conform to all applicable LORS, including the requirements and description listed below. No increment of construction of these facilities shall commence until the CPM approves the documents required in the Verification for TSE-5. The project owner shall submit the required number of copies of the design drawings and calculations, as determined by the CBO.~~

~~Once approved, the project owner shall inform the CPM and CBO of any anticipated changes to the design, and shall submit a detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change to the CPM and CBO for review and approval. The BEP II 500 kV integration switchyard shall have four switchbays with 500 kV circuit breakers. The high voltage transformer terminals of two CTGs and one STG unit shall be connected by overhead conductors to three switch bays. The fourth bay shall be connected to a 500 kV 2-2156 Aluminum Conductor Steel Reinforced (ACSR) interconnecting line to a new 500 kV substation to be built within the existing Buck Boulevard Substation. The Integration Switchyard shall be connected to the Buck Blvd. 500 kV Bus via a 500 kV single circuit transmission line.~~

~~a) The power plant Integration Switchyard and outlet line shall meet or exceed the electrical, mechanical, civil and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code and Regulations (Title 8), Articles 35, 36 and 37 of the "*High Voltage Electric Safety Orders*",~~ Western California ISO and/or SCE ~~Western Interconnection standards, IEEE grounding standards, IEEE Grounding Standards, National Electric Code (NEC) and related industry standards.~~

~~b) Breakers and busses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.~~

~~c) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner's standards.~~

~~d) The project conductors shall be sized to accommodate the full output from the project.~~

~~e) Termination facilities shall comply with applicable Western~~ SCE ~~Western interconnection standards.~~

~~f) The project owner shall provide to the CPM:~~

~~a diagram including BEP II integration switchyard and the new Buck Boulevard 500 kV substation showing major equipment and their ratings.~~

~~(2) a description of any mitigation measures selected by project owner (to offset reliability criteria violations) and letters or reports of acceptance from the affected transmission owners and where applicable, the CA ISO.~~

~~ii) Executed Facility Interconnection Agreement between the BEP II project owner and Western.~~

~~i) The Special Protection System (SPS) sequencing and timing, if applicable;~~

~~ii) A letter stating that the mitigation measures or projects selected by the transmission owner for each reliability criteria violation, for which the project is responsible, are acceptable;~~

~~iii) A Deliverability Assessment report from Western and/or the California ISO if required by either entity. the California ISO and/or SCE according to the California ISO Tariff;~~

~~iv) A letter from SCE and/or the California ISO confirming that the Blythe II 500 kV generation tie line to the new SCE 500 kV Colorado River Substation will interconnect through the proposed new 500 kV Keim substation;~~

~~iv) A copy of the executed LGIA signed by WESTERN the California ISO and the project owner; which must include the new proposed Keim 500 kV substation as an interconnection facility (in Appendix A of the LGIA) in addition to the new Blythe II 500 kV integration switchyard and the Blythe II 500 kV generator tie line to the SCE 500 kV Colorado River substation, and~~

~~v) The Operational Study Report by Western based on the Current Operational Date (COD). of the new Keim 500 kV substation prior to completing construction of the Blythe II 500 kV generator tie line.~~

~~Verification: At least 90~~ 60 ~~days prior to the start of construction of transmission facilities to the first point of interconnection at the Buck Blvd. Substation (or a lesser number of days mutually agreed to by the project owner and CBO), the project owner shall submit to the CBO and where applicable to the CPM for approval:~~

a) ~~Design drawings, specifications and calculations conforming with CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code of Regulations, Articles 35, 36 and 37 of the "*High Voltage Electric Safety Orders*", Western Interconnection Standards, California ISO Standards, National Electric Code (NEC), applicable interconnection standards and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems and major switchyard equipment listed in Table 1 of Condition TSE-1;~~

b) ~~For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on "worst case conditions"[1] and a statement signed and sealed by the registered engineer in responsible charge, or other acceptable alternative verification, that the transmission element(s) will conform with CPUC General Order 95 or National Electric Safety code (NESC), Title 8,of the California Code of Regulations, Articles 35, 36 and 37 of the "*High Voltage Electric Safety Orders*", California ISO Standards, IEEE grounding standards, National Electric Code (NEC), applicable interconnection standards, and related industry standards.~~

c) ~~Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in responsible charge, a route map, and an engineering description of equipment and the configurations covered by requirements TSE-5 a) through f); above.~~

d) ~~Item f) i) above submitted to the CPM for review and docketing.~~

e) ~~The Special Protection System (SPS) sequencing and timing if applicable shall be provided concurrently to the CPM.~~

f) ~~A letter stating that the mitigation measures or projects selected by the transmission owner for each reliability criteria violation, for which the project is responsible, are acceptable,~~

g) ~~A Deliverability Assessment report from Western and/or the California ISO if required by either entity .the California ISO and/SCE under the California ISO Tariff.~~

h) ~~A letter from SCE and/or the California ISO confirming that the Blythe II generation overhead 500 kV tie line to the new SCE 500 kV CRS will interconnect through the proposed new Kiem 500 kV substation.~~

i) ~~A copy of the executed LGIA signed by Western. the California ISO and the project owner. which must include the new Keim 500 kV substation as an interconnection facility (in the Appendix A of the LGIA) between the new Blythe II 500 kV integration switchyard and the 500 kV Colorado River substation, and~~

j) ~~The Operational Study Report by Western based on the current Commercial Operation Date (COD).~~

[1] Worst-case conditions for the foundations would include for instance, a dead-end or angle pole.

~~Prior to the construction of or start of modification of transmission facilities, the project owner shall inform the CBO and the CPM of any anticipated changes to the design that are different from the design previously submitted and approved and shall submit a detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change to the CPM and CBO for review and approval.~~

TSE-5 The project owner shall ensure that the design, construction and operation of the proposed transmission facilities will conform to all applicable LORS, and the requirements listed below. The project owner shall submit the required number of copies of the design drawings and calculations, as determined by the CBO.

Once approved, the project owner shall inform the CPM and CBO of any anticipated changes to the design, and shall submit a detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change to the CPM and CBO for review and approval.

a) The power plant Integration Switchyard and outlet line shall meet or exceed the electrical, mechanical, civil and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code and Regulations (Title 8), Articles 35, 36 and 37 of the "*High Voltage Electric Safety Orders*", Western Interconnection standards, IEEE Grounding Standards, National Electric Code (NEC) and related industry standards.

b) Breakers and busses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.

c) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner's standards.

d) The project conductors shall be sized to accommodate the full output from the project.

e) Termination facilities shall comply with applicable Western interconnection standards.

f) The project owner shall provide to the CPM:

i) The Special Protection System (SPS) sequencing and timing, if applicable;

ii) A letter stating that the mitigation measures or projects selected by the transmission owner for each reliability criteria violation, for which the project is responsible, are acceptable;

iii) A Deliverability Assessment report from Western and/or the California ISO if required by either entity

iv) A copy of the executed LGIA signed by WESTERN and the project owner;

v) The Operational Study Report by Western based on the Current Operational Date (COD)

Verification: At least 60 days prior to the start of construction of transmission facilities (or a lesser number of days mutually agreed to by the project owner and CBO), the project owner shall submit to the CBO and where applicable to the CPM for approval:

a) **Design drawings, specifications and calculations conforming with CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code of Regulations, Articles 35, 36 and 37 of the "*High Voltage Electric Safety Orders*", Western Interconnection Standards, National Electric Code (NEC), and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems and major switchyard equipment;**

b) **For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on "worst case conditions" [2] and a statement signed and sealed by the registered engineer in responsible charge, or other acceptable alternative verification, that the transmission element(s) will conform with CPUC General Order 95 or National Electric Safety code (NESC), Title 8, of the California Code of Regulations, Articles 35, 36 and 37 of the "*High Voltage Electric Safety Orders*", California ISO Standard, National Electric Code (NEC), and related industry standards.**

c) **Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in responsible charge, a route map, and an engineering description of equipment and the configurations covered by requirements TSE-5 a) through f);**

d) **Item f) i) above submitted to the CPM for review and docketing.**

e) **The Special Protection System (SPS) sequencing and timing if applicable shall be provided concurrently to the CPM.**

f) **A letter stating that the mitigation measures or projects selected by the transmission owner for each reliability criteria violation, for which the project is responsible, are acceptable,**

g) **A Deliverability Assessment report from Western and/or the California ISO if required by either entity,**

h) **A copy of the executed LGIA signed by Western,**

[1] Worst-case conditions for the foundations would include for instance, a dead-end or angle pole.

i) **The Operational Study Report by Western based on the current Commercial Operation Date (COD).**

Prior to the construction of or start of modification of transmission facilities, the project owner shall inform the CBO and the CPM of any anticipated changes to the design that are different from the design previously submitted and approved and shall submit a detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change to the CPM and CBO for review and approval.

~~**TSE-6** The project owner shall inform the CPM and CBO of any impending changes, which may not conform to the requirements **TSE-5** a) through e), and have not received CPM and CBO approval, and request approval to implement such changes. A detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change shall accompany the request. Construction involving changed equipment shall not begin without prior written approval of the changes by the CBO and the CPM.~~

~~**Verification:** At least 60 days prior to the construction of transmission facilities to the first point of interconnection at the Buck Blvd. Substation, the project owner shall inform the CBO and the CPM of any impending changes which may not conform to requirements of **TSE-5** and request approval to implement such changes.~~

TSE-7 The project owner shall provide the following notice~~s~~ to the ~~Western Area Power Administration, Desert Southwest Region (Western, DSR) and the California Independent System Operator (Cal- California ISO)~~ **Western Desert Southwest Region,** prior to synchronizing the facility with the Western transmission system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the ~~Western, DSR and Cal-~~ ~~California ISO,~~ **Western** a letter stating the proposed date of synchronization; and

2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the ~~Western, DSR and Cal-~~ ~~*California ISO Outage Coordination Departmen*~~t **Western**.

Verification: The project owner shall provide copies of the ~~Western, DSR and Cal-~~ California ISO letter~~s~~ to the CPM when they are sent to the ~~Western, DSR and Cal-~~ **California ISO** **Western, Desert Southwest Region (DSR) ,** one week prior to initial synchronization with the grid. The project owner shall contact the ~~Western, DSR and Cal- California ISO Outage Coordination Department,~~ **Western, DSR,** Monday through Friday, between the hours of 07:00 and 15:30 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the ~~Western, DSR and Cal- California ISO~~ **with Western, DSR** shall be provided electronically to the CPM one day before synchronizing the facility with the ~~Western, DSR~~ California transmission system for the first time.

TSE-8 The project owner shall be responsible for the inspection of the ~~power plant Integration Switchyard and transmission tie line to the Buck Blvd~~ **transmission facilities**~~. Substation~~ during and after project construction, and any subsequent CPM and CBO approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8, CCR, Articles 35, 36 and 37 of the~~, "~~*High Voltage Electric Safety Orders*~~"~~, applicable interconnection standards, ~~IEEE grounding standards,~~ NEC and related industry standards. In case of non-conformance, the project owner shall inform the CPM and CBO in writing, within 10 days of discovering such nonconformance and describe the corrective action(s) to be taken.

Verification: Within 60 days after first synchronization of the project, the project owner shall transmit to the CPM and CBO:

1. "As built" engineering description(s) and one-line drawings of the electrical portion of the facilities ~~Integration Switchyard and the 500 kV line to the Buck Blvd. Substation~~ signed and sealed by the registered electrical engineer in responsible charge. A statement attesting to conformance with CPUC GO-95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the~~, "~~*High Voltage Electric Safety Orders*, ~~IEEE grounding standards, and~~ applicable interconnection standards, NEC, **and** related industry standards, and these conditions shall be provided concurrently.
2. An "as built" engineering description of the mechanical, structural, and civil portion of the transmission facilities signed and sealed by the registered engineer in responsible charge or acceptable alternative verification. "As built" drawings of the electrical, mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, if requested, for CPM audit as set forth in the ~~"~~*Compliance Monitoring Plan*~~"~~.
3. A summary of inspections of the completed transmission facilities, and identification of any nonconforming work and corrective actions taken, signed and sealed by the registered engineer in charge.

~~**TSE-9** The Project Owner shall not commence construction of BEP II until the Desert Southwest Transmission Project (DSWTP) or an equivalent transmission Project or Upgrade as determined by the CPM has received all necessary permits to build the Project or Upgrade and has a definite construction schedule.~~

~~**Verification:** At least 60 days prior to the start of rough grading or construction, the Project Owner shall submit the following to the CPM:~~

~~1. A list of all permits, agreements and approvals required for the construction, operation and interconnection of the DSWTP or the approved equivalent Project or Upgrade.~~

~~2. The permits, agreements and approvals required for the construction, operation and interconnection of the DSWTP or the approved equivalent Project or Upgrade when they become available.~~

~~3. A definite schedule for the construction and completion of the DSWTP or approved equivalent Project or Upgrade.~~

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

ASE2015g. AltaGas Sonoran Energy Inc. Data Responses Set 1 (TN 206606). Docketed on 11/12/2015.

ASE2015h. AltaGas Sonoran Energy Inc. Sonoran Energy Project – Data Responses Set 1 – Modeling CDs (TN 206608). Docketed on 11/12/2015.

ASE2015i. AltaGas Sonoran Energy Inc. Data Responses Set 1 – Additional Response to Staff's Data Requests 2 and 4 (TN 207068). Docketed on 12/17/2015.

ASE2015j. AltaGas Sonoran Energy Inc. Data Responses Set 1 – Additional Response to Staff's Data Requests 2 and 4: Modeling CD (TN 207073). Docketed on 12/17/2015.

CEC2005a. California Energy Commission. Final Staff Assessment (TN 34141). Docketed on 4/29/2005.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

CEC 2015a. California Energy Commission. Data Requests Set No. 1 (1-58) (TN 206331. Docketed on 10/12 /2015

SONORAN ENERGY PROJECT (02-AFC-01C)

Petition to Amend Final Commission Decision
ALTERNATIVES
Steven Kerr and David Vidaver

SUMMARY OF CONCLUSIONS

Staff reviewed alternatives previously analyzed for the licensed Blythe Energy Project Phase II (BEP II) design and related facilities, alternative sites, and the "no project" alternative. Staff also reviewed the preferred resource alternatives of renewable generation technologies, which were previously analyzed, including central-station solar, geothermal, biomass, and wind. In addition, staff provided a discussion of "more preferred" resources including energy efficiency and demand response programs, distributed generation, and energy storage, which were not considered in previous staff assessments of the BEP II. **Alternatives** previously found to be infeasible would not now be feasible, and would not substantially reduce one or more significant effects of the BEP II. In addition, new information does not show alternatives which are considerably different from those analyzed in the previous staff assessment for the BEP II would substantially reduce one or more significant effects on the environment.

In accordance with California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Commission Decision is necessary for **Alternatives**. The Committee may rely upon the environmental analysis and conclusions of the 2005 Commission Decision with regards to **Alternatives** and does not need to re-analyze them.

INTRODUCTION

Staff reviewed the 2005 California Energy Commission (Energy Commission) Decision (2005 Decision) and 2012 Order approving the 2009 Petition to Amend (2012 Order), and analyzed the changes to the licensed BEP II. The primary change is to replace the licensed combined-cycle gas-fired generation technology with a more efficient combined-cycle gas-fired generation technology, which was unavailable during the licensing of the project. The petition also requests that the BEP II name be changed to Sonoran Energy Project (SEP).

SUMMARY OF DECISION

The list below provides a short summary of the licensed BEP II Energy Commission Decision with regards to project alternatives. Based on the evidence presented in the original proceeding, the Energy Commission made the following findings and conclusions:

1. Developing the project at an alternative site would defeat a core goal and objectives of the project;

2. An alternative site would not substantially lessen the potential impacts of the project, which are mitigated to insignificance by the Conditions of Certification;
3. The Energy Commission does not believe that alternative designs are feasible or offer a valuable reduction in impacts;
4. The Energy Commission does not believe that alternative technologies present feasible alternatives to the proposed project; and
5. The “no project” alternative will not meet the need for new reliable electricity and would lead to the continued use of less efficient existing, older power plants. The “no project” alternative would also cause the loss of local economic benefits. Therefore, the “no project” alternative is inferior to the proposed project. (CEC2005b, pg. 286)

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

The LORS compatibility is not a requirement of an Alternatives analysis.

ENVIRONMENTAL IMPACT ANALYSIS

Staff reviewed the 2005 Decision, 2012 Order, and the SEP Petition to Amend (PTA) for potential environmental effects. Based on this review, staff determined that the proposed amendment would not change the staff review of project alternatives and would have no impact on project alternatives criteria under the CEQA Guidelines, Section 15126.6(2), for alternative locations where CEQA requires a limited new analysis. Where a previous document has sufficiently analyzed a range of reasonable alternative locations and environmental impacts for projects with the same basic purpose, the lead agency should review the previous document. The environmental document may rely on the previous document to help it assess the feasibility of potential project alternatives to the extent the circumstances remain substantially the same as they relate to the alternative. (*Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal.3d 553, 573).

The SEP proposes to change the approved BEP II primarily by replacing the licensed combined-cycle gas-fired generation technology with a more efficient combined-cycle gas-fired generation technology, which was unavailable during the licensing of the project. The proposed SEP would decrease the net output from 569 MW to 553 MW (ASE2015a, pg. 1-1 & 3-156). The SEP would replace two previously proposed Siemens gas turbines with one GE gas turbine. The SEP would be constructed on up to 34 acres within the existing 76-acre licensed BEP II site (ASE2015a, p. 3-94). The SEP would define a new point of electrical interconnection to the existing Buck Boulevard substation rather than the previously proposed Keim substation (ASE2015a, pg. 1-1 to 1-2).

ALTERNATIVE SITES EVALUATION

The 2005 Decision analyzed four alternative locations for the BEP II. Three sites were in the Blythe area (Blythe Airport Site, Interstate 10 (I-10) Site, and South of Blythe Site), and one site was adjacent to the Devers Substation north of Palm Springs (CEC2005b, p. 280). Staff's review of the alternative discussion for the 2005 BEP II concludes that it is still current and applicable to the SEP.

Energy Commission staff's analysis of alternative sites was predicated upon its conclusion that the proposed site had unmitigable water resource and aviation impacts (CEC2005b, p. 279). The Energy Commission determined that constructing BEP II adjacent to the existing Blythe Energy Project (BEP) offered two advantages: 1) a reduction in the need to construct redundant facilities and infrastructure; and 2) BEP II will be constructed on disturbed and evaluated land for which biological mitigation has been provided in the form of desert tortoise mitigation (CEC2005b, p. 281). These advantages also extend to the construction of SEP adjacent to the existing BEP. Based on their findings in the 2005 Decision that the use of groundwater would not cause significant water resources impacts and that aviation impacts could be mitigated to insignificance, the Energy Commission concluded that an alternative site would not be preferable to the proposed site, and a more detailed alternative site analysis was not needed (CEC2005b, p. 283).

ALTERNATIVE DESIGN

In addition to alternative locations, the 2005 Decision evaluated whether an alternative cooling system should be utilized for the BEP II. In the original proceeding, Energy Commission staff proposed an alternative cooling system using either drycooling or agricultural return water from the Rannells Canal. The Energy Commission found that the alternatives were unnecessary since the BEP II, using groundwater, would not cause an adverse environmental impact. Moreover, dry cooling in the Blythe desert setting was found to be effectively infeasible to meet the project objectives in 2005. (CEC2005b, p. 283)

In light of current environmental conditions and updated policy considerations, Water Resources staff recommends that the amended SEP be modified to incorporate dry cooling to address project water use impacts. The project's cooling system and related impacts are analyzed and discussed in detail within the **Soil and Water Resources** section of this analysis. For the purposes of analyzing the proposed SEP amendment, Alternatives staff views the selection of the project's cooling system as one component of the overall combined-cycle gas-fired generation power plant project rather than a separate alternative to the amended project. Accordingly, Condition of Certification **SOIL&WATER-10** includes staff's recommended changes to significantly reduce the project's annual water use limit, which could be achieved by incorporating a dry cooling system. The **Air Quality**, **Land Use**, **Biological Resources**, **Visual Resources**, **Noise and Vibration**, **Public Health**, **Socioeconomics,** and **Traffic and Transportation** sections of this document have also addressed the issue incorporating dry cooling.

PREFERRED RESOURCE ALTERNATIVES

The 2011 Commission Decision also evaluated whether selected alternative, renewable generation technologies would meet the project's objectives, as determined by staff, which include:

1. Construction and operation of a merchant power plant with access to multiple markets;
2. Location near a substation and key infrastructure for natural gas, water supply and transmission lines; and
3. Generation of approximately 520 MW of electricity (The October 2009 amendment increased the generation of the licensed BEP II to 569 MW. The amended SEP would generate 553 MW). (CEC2005b, p. 282)

The technologies evaluated included central-station solar, geothermal, biomass, and wind. Solar technologies were eliminated from further consideration because they require a large amount of land to produce the same amount of electricity. Geothermal resources were eliminated from further consideration because there are no geothermal resources in the project vicinity, making this technology an infeasible alternative. Biomass facilities were eliminated from further consideration because they are typically smaller than the capacity of the project and typically produce greater emissions than the equivalent gas-fired combustion turbine technology. Lastly, wind generation was eliminated from further consideration because it potentially creates numerous impacts and also requires a large amount of land with reliable and adequate wind energy resources. (CEC2005b, p.279, 283-285)

The 2005 staff assessment of the BEP II did not consider preferred resources other than central-station renewable generation as alternatives to the project. This is in contrast to more recent staff assessments[1] of natural gas-fired generation projects, which have explicitly discussed resources above such projects in the State's loading order as alternatives to their development. These "more preferred" resources include energy efficiency and demand response programs, distributed renewable generation, and energy storage.

The loading order requires that the state, in meeting its energy needs, "invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply." (CEC 2008, p.1) The California Public Utilities Commission (CPUC) imposes the loading order on the procurement activities of the state's investor-owned utilities by statute (Pub. Utilities Code, § 454.5, subd. (b)(9)(C)), requiring that *all* cost-effective demand-side and renewable resources that can be feasibly and reliably developed be procured before natural gas-fired generation. The loading order recognizes, however, that the development of natural gas-fired generation will be required to meet the state's energy needs due, in part, to the inability to develop sufficient quantities of preferred resources (CEC 2008, p.15). The CPUC has

[1] For example, Carlsbad Energy Center Project, El Segundo Redevelopment Project, Palmdale Energy Project, and Puente Power Project.

also found that, even when and where preferred resources are available, the development of new natural gas-fired generation may still be necessary to ensure reliable service.[2] The roles that natural gas-fired generation plays in a low-carbon electricity system are well-documented;[3] this dispatchable natural gas-fired generation may be required to be in specific transmission-constrained areas, have specific operating characteristics, or both.

As a condition of approving a utility contract with a new natural gas-fired generation resource (or the recovery of costs in rates of developing new utility-owned natural gas-fired generation), the CPUC requires that the investment be consistent with the loading order. The first step in ensuring that this is the case occurs in the CPUC's biennial Long-term Procurement Planning (LTPP) proceeding, where the amount of new, natural-gas fired generation capacity needed to ensure reliability over a ten-year planning horizon is determined. Estimates of preferred resource (energy efficiency and demand response programs, distributed and central station renewable generation, and storage) development over the planning horizon are used to determine the residual need for natural gas-fired generation capacity. As noted above, consistency with the loading order requires that all cost-effective preferred resources that can be feasibly and reliably developed are assumed by the CPUC to be deployed, minimizing the amount of natural gas-fired generation that is needed. The second step in ensuring the consistency of utility procurement with the loading order takes place when the CPUC rules upon the utility's application to recover the costs associated with the procurement of specific resources in rates. Should the utility be found to have not procured all cost-effective preferred resources that were submitted (or could have been submitted) into its Request for Offers (RFO), the procurement is likely to be found to violate the loading order and the application rejected.

Should the Energy Commission find that preferred resources, in quantities above those assumed by the CPUC to be available for development, are alternatives to a natural gas-fired generation project, it would effectively be usurping the CPUC's responsibility to determine the extent to which demand-side programs, renewable generation, and storage can be safely relied upon to meet the state's energy needs and ensure reliable operation of the state's electricity system. The Energy Commission provides inputs to the CPUC in the LTPP proceeding, producing the demand forecast and estimates of energy efficiency savings and distributed (self-) generation over the ten-year planning horizon. These inputs are shaped by stakeholder participation in the Energy Commission's Integrated Energy Policy Report (IEPR) proceeding. Stakeholder participation in the LTPP proceeding provides an opportunity to influence CPUC findings regarding the availability of other cost-effective preferred resources; this opportunity is provided again when utilities apply for the recovery of costs incurred when

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[2] For example, in its 2012 LTPP proceeding (R.12-03-014), the CPUC required Southern California Edison to procure at least 1,000 MW of new natural gas-fired generation capacity in the Western Los Angeles sub-area of the Los Angeles basin (D.13-02-015; February 13, 2013).

[3] See, for example, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, MRW and Associates (CEC-700-2009-009; May 2009), available at http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF

contracting with a natural gas-fired project. The Energy Commission's power plant siting process is distinguished from the IEPR and LTPP proceedings.[4]

Most merchant natural gas-fired generation projects that submit applications for certification to the Energy Commission do not have a long-term contract with a utility that has been approved by the CPUC. In these instances there has been no determination that the project is consistent with the loading order. Denying certification of projects because they have not secured such a contract, however, or delaying certification until a contract is approved, is not in the public interest.

- Energy Commission certification of fossil generation without a long-term contract does not result in the development of more fossil generation than that needed to reliably operate the system, as only those projects with approved contracts, i.e., found to be consistent with the loading order, are built.[5]; and

- The CPUC does not require Energy Commission certification for a generation project to participate in a utility request for offers (RFOs), nor does the Energy Commission require a utility contract for a project to be considered for certification. Requiring the sequencing of these processes would not only lengthen the time needed to bring projects on line and thus potentially threaten system reliability, it would reduce the number of projects that could compete in utility RFOs for new natural gas-fired generation capacity. This could lead to non-competitive solicitations, unnecessarily raising ratepayer costs.

NO PROJECT ALTERNATIVE

CEQA requires an evaluation of the "no project" alternative "… 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. 14, § 15126.6(e)(1).) The "no project" analysis assumes: (a) that baseline environmental conditions would not change because the proposed project would not be installed; and (b) that the events or actions reasonably expected to occur in the foreseeable future would occur if the project were not approved. (Cal. Code Regs., tit. 14, § 15126.6(e)(2).)

This analysis for the proposed SEP considers what would be reasonably expected to occur in the foreseeable future if the project were not approved, based on current plans and consistent with available infrastructure and community services. For the purposes of this analysis, the no project alternative is considered to be the construction and operation of the licensed BEP II as last amended in 2012.

[4] California's publicly-owned utilities (POU) and their investment in new natural gas-fired generation are not subject to CPUC jurisdiction. The POUs are however, subject to legislation that requires the development of preferred resources, e.g., the Clean Energy and Pollution Reduction Act of 2015 (SB 350, De León), are subject to the Brown (open meeting) Act, and have governing authorities that are elected (or are responsible to elected officials).

[5] Only one merchant plant (Inland Empire) has been developed since the energy crisis (2000 – 2001) without a long-term contract, and the conditions that led to that merchant plant are specific to that one facility. This plant, in turn, provides capacity and ancillary services that obviate the need for energy and capacity from other, new gas-fired generation.

In the 2005 Commission Decision, the Energy Commission found that in all technical areas, with the implementation of the Conditions of Certification, all potential adverse impacts would be mitigated to insignificance. (With regards to the “no project” alternative, the Energy Commission found that in the absence of the BEP II project, the “no project” alternative would not meet the need for new reliable electricity and would lead to the continued use of less efficient existing, older power plants (CEC2005b, p. 286). The amended SEP is in keeping with this finding in that the project owner seeks to install newer, higher-efficiency combined-cycle generation equipment that was not yet available at the time of the 2012 Order, rather than the currently licensed equipment that is a less efficient, older power plant technology. Furthermore, the amended SEP would help provide more reliable electricity by better supporting the integration of California’s renewable resources, which have grown significantly since the project was originally licensed in 2005 (ASE2015a, p. 1-2).

Based on previous findings made for environmental impacts of the BEP II summarized in the 2005 Commission Decision, the proposed SEP would be similar to or reduce environmental impacts in all resource areas. Therefore, although the “no project” alternative of constructing the project as currently licensed would meet the project objectives, staff concurs with conclusions in the 2005 Commission Decision that the “no project” alternative is not superior to the proposed project and would result in overall greater environmental impacts as compared to the amended SEP (CEC2005b, p. 286).

CONCLUSIONS AND RECOMMENDATIONS

Staff reviewed alternatives previously analyzed for the BEP II design and related facilities, alternative sites, and the “no project” alternative. Staff also reviewed the preferred resource alternatives of renewable generation technologies, which were previously analyzed, including central-station solar, geothermal, biomass, and wind. In addition, staff provided a discussion of “more preferred” resources including energy efficiency and demand response programs, distributed generation, and energy storage, which were not considered in previous staff assessments of the BEP II. For the reasons discussed above, staff does not believe that preferred resources present feasible alternatives to the amended SEP.

Alternatives previously found to be infeasible would not now be feasible, and would not substantially reduce one or more significant effects of the BEP II based on new information of substantial importance which was not known in 2005. Similarly, new information does not show alternatives which are considerably different from those analyzed in the previous staff assessment for the BEP II would substantially reduce one or more significant effects on the environment.

In accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2005 Commission Decision is necessary for Alternatives. The Committee may rely upon the environmental analysis and conclusions of the 2005 Commission Decision with regards to Alternatives and does not need to re-analyze them due to the following:

- The changes in the Petition to Amend (PTA) would not create new significant environmental effects or substantial increases in the severity of previously identified significant effects;
- The PTA does not propose substantial changes which would require major revisions of the Alternatives analysis in the 2005 Commission Decision; and
- The circumstances under which the amended SEP would be undertaken would not require major revisions of the Alternatives analysis in the 2005 Commission Decision.

Staff's conclusion is supported by the fact that the 2005 staff assessment for the BEP II contains an acceptable analysis of a reasonable range of alternatives to the project and contains an adequate review of alternative design and related facilities, alternative sites, preferred resource alternatives, and the "no project" alternative.

REFERENCES

ASE2015a. AltaGas Sonoran Energy Inc. Petition to Amend (TN 205652). Docketed on 8/7/2015.

CEC2005b. California Energy Commission. Final Commission Decision (TN 64945). Docketed on 4/26/2015.

CEC 2008. California Energy Action Plan 2008 Update, (CEC-100-2008-001). Available: http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF

COMPLIANCE CONDITIONS AND MONITORING PLAN

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SONORAN ENERGY PROJECT (02-AFC-1C)

Petition to Amend Final Commission Decision
COMPLIANCE CONDITIONS AND COMPLIANCE MONITORING PLAN
Mary Dyas

INTRODUCTION

The Sonoran Energy Project (SEP) Compliance Conditions of Certification, including a Compliance Monitoring Plan (Compliance Plan), are established as required by Public Resources Code section 25532. The Compliance Plan provides a means for assuring that the facility is constructed, operated, and closed in compliance with public health and safety and environmental law; all other applicable laws, ordinances, regulations, and standards (LORS); and the conditions adopted by the California Energy Commission (Energy Commission) and specified in the Energy Commission's written Decision on the project's Application for Certification (AFC), or otherwise required by law.

The Compliance Plan is composed of elements that:

- set forth the duties and responsibilities of the compliance project manager (CPM), the project owner or operator (project owner), delegate agencies, and others;
- set forth the requirements for handling confidential records and maintaining the compliance record;
- state procedures for settling disputes and making post-certification changes;
- state the requirements for periodic compliance reports and other administrative procedures that are necessary to verify the compliance status for all Energy Commission-approved conditions of certification;
- establish contingency planning, facility non-operation protocols, and closure requirements; and
- establish a tracking method for the technical area conditions of certification that contain measures required to mitigate potentially adverse project impacts associated with construction, operation, and closure below a level of significance; each technical condition of certification also includes one or more verification provisions that describe the means of assuring that the condition has been satisfied.

This section has been updated to reflect current definitions, clarify roles and responsibilities, changes in amendment processing. The Compliance Conditions of Certification have been updated based on lessons learned from previous cases.

KEY PROJECT EVENT 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.~~

The following terms and definitions help determine when various conditions of certification are implemented.

PROJECT CERTIFICATION

Project certification occurs on the day the Energy Commission dockets its decision after adopting it at a publically noticed Business Meeting or hearing. At that time, all Energy Commission conditions of certification become binding on the project owner and the proposed facility. Also at that time, the project enters the compliance phase. It retains the same docket number it had during its siting

review, but the letter "C" is added at the end (for example, 02-AFC-1C) to differentiate the compliance phase activities from those of the certification proceeding.

SITE ASSESSMENT AND PRE-CONSTRUCTION ACTIVITIES

The below-listed site assessment and pre-construction activities may be initiated or completed prior to the start of construction, subject to the CPM's approval of the specific site assessment or pre-construction activities.

Site assessment and pre-construction activities include the following, but only to the extent the activities are minimally disruptive to soil and vegetation and will not affect listed or special-status species or other sensitive resources:

1. **the installation of environmental monitoring equipment;**
2. **a minimally invasive soil or geological investigation;**
3. **a topographical survey;**
4. **any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility; and**
5. **any minimally invasive work to provide safe access to the site for any of the purposes specified in 1 through 4, above.**

SITE MOBILIZATION AND CONSTRUCTION

When a condition of certification requires the project owner to take an action or obtain CPM approval prior to the start of construction, or within a period of time relative to the start of construction, that action must be taken, or approval must be obtained, prior to any site mobilization or construction activities, as defined below.

Site mobilization and construction activities are those necessary to provide site access for construction mobilization and facility installation, including both temporary and permanent equipment and structures, as determined by the CPM.

Site mobilization and construction activities include, but are not limited to:

1. **ground disturbance activities like grading, boring, trenching, leveling, mechanical clearing, grubbing, and scraping;**
2. **site preparation activities, such as access roads, temporary fencing, trailer and utility installation, construction equipment installation and storage, equipment and supply laydown areas, borrow and fill sites, temporary parking facilities, chemical spraying, controlled burns; and**
3. **permanent installation activities for all facility and linear structures, including access roads, fencing, utilities, parking facilities, equipment storage, mitigation and landscaping activities, and other installations, as applicable.**

COMMISSIONING

Commissioning activities test the functionality of the installed components and systems to ensure the facility operates safely and reliably. Commissioning provides a multistage, integrated, and disciplined approach to testing, calibrating, and proving all of the project's systems, software, and networks. For compliance monitoring purposes, examples of commissioning activities include interface connection and utility pre-testing, "cold" and "hot" electrical testing, system pressurization and optimization tests, grid synchronization, and combustion turbine "first fire" and tuning.

START OF COMMERCIAL OPERATION

For compliance monitoring purposes, "commercial operation" ~~is that phase of project development that begins after the completion of start-up and commissioning~~ **or "operation" begins once commissioning activities are complete**, ~~where the power plant has reached steady-state production of electricity with reliability at the rated capacity~~ **the certificate of occupancy has been issued, and the power plant has reached reliable steady-state electrical production**. ~~For example, at the start of commercial operation, plant control is usually transferred from the construction manager to the plant operations manager.~~ **At the start of commercial operation, plant control is usually transferred from the construction manager to the plant operations manager. Operation activities can include a steady state of electrical production, or, for "peaker plants," a seasonal or on-demand operational regime to meet peak load demands.**

NON-OPERATION AND CLOSURE

Non-operation is time-limited and can encompass part or all of a facility. Non-operation can be a planned event, usually for equipment maintenance or repair, or unplanned, usually the result of unanticipated events or emergencies. Closure is a facility shutdown with no intent to restart operation. It may also be the cumulative result of unsuccessful efforts to re-start over an increasingly lengthy period of non-operation, condemned by inadequate means and/or lack of a viable plan. Facility closures can occur due to a variety of factors, including, but not limited to, irreparable damage and/or functional or economic obsolescence.

ROLES AND RESPONSIBILITIES

Provided below is a generalized description of the compliance roles and responsibilities for Energy Commission staff (staff) and the project owner for the construction and operation of the SEP project.

Compliance Project Manager Responsibilities

~~A Compliance Project Manager (CPM) will oversee the compliance monitoring and shall be responsible for:~~ **The CPM's compliance monitoring and project oversight responsibilities include:**

1. ensuring that the design, construction, operation, and closure of the project facilities are in compliance with the terms and conditions of the ~~Energy Commission~~ Decision;
2. resolving complaints;
3. processing post-certification ~~changes to the conditions of certification,~~ **project amendments for changes to the** project description, **conditions of certification** and ownership or operational control**, and requests for extension of the deadline for the start of construction (see COM-10 for instructions on filing a Petition to Amend or to extend a construction start date)**;
4. documenting and tracking compliance filings; and
5. ensuring that the compliance files are maintained and accessible.

The CPM is the **central** contact person for the Energy Commission ~~and~~ **during project pre-construction, construction, operation, emergency response, and closure. The CPM** will consult with **the** appropriate responsible ~~agencies and the Energy Commission~~ **parties** when handling **compliance issues,** disputes, complaints and amendments.

All project compliance submittals are submitted to the CPM for processing. Where a submittal **requires CPM approval,** required by a condition of certification requires CPM approval, the approval will involve ~~all~~ appropriate **Energy Commission technical** staff and management. **All submittals must include searchable electronic versions (.pdf, MS Word, or equivalent files).**

~~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~~ **usually** schedules 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.~~ **These meetings are used to assist the Energy Commission and the project owner's technical staff in the status review of all required pre-construction or pre-operation conditions of certification, and facilitate staff taking proper action if outstanding conditions remain.** In addition, these meetings shall ensure, to the extent possible, that Energy Commission**'s** conditions **of certification do** ~~will~~ not delay the construction and operation of the plant due to ~~oversight and to preclude any~~ last minute~~,~~ unforeseen issues **or a compliance oversight** ~~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**s the following documents and information** as ~~a~~ public record, in either the Compliance file or Docket**s Unit** file**s**, for the life of the project (or other period as ~~required~~ **specified**):

- all documents demonstrating compliance with any legal requirements relating to the construction**,** ~~and~~ operation**, and closure** of the facility;
- all ~~m~~**M**onthly and ~~a~~**A**nnual ~~c~~**C**ompliance ~~r~~**R**eports **(MCRs, ACRs) and other required Periodic Compliance Reports (PCRs)** filed by the project owner;
- all **project-related formal** complaints of **alleged** noncompliance filed with the Energy Commission; and
- all petitions for project or condition **of certification** changes and the resulting staff or Energy Commission action.

Chief Building Official Delegation and Agency Cooperation

Under the California Building Code standards, while monitoring project construction and operation, staff acts as, and has the authority of, the Chief Building Official (CBO). Staff may delegate some CBO responsibility to either an independent third-party contractor or a local building official. However, staff retains CBO authority when selecting a delegate CBO (DCBO), including the interpretation and enforcement of state and local codes, and the use of discretion, as necessary, in implementing the various codes and standards.

The DCBO will be responsible for facilitating compliance with all environmental conditions of certification, including cultural resources, and for the implementation of all appropriate codes, standards, and Energy Commission requirements. The DCBO will conduct on-site (including linear facilities) reviews and inspections at intervals necessary to fulfill these responsibilities. The project owner will pay all DCBO fees necessary to cover the costs of these reviews and inspections.

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.~~

The project owner is responsible for ensuring that all conditions of certification and applicable LORS in the SEP amended Decision are satisfied. The project owner will submit all compliance submittals to the CPM for processing unless the conditions specify another recipient. The Compliance Conditions regarding post-

certification changes specify measures that the project owner must take when modifying the project's design, operation, or performance requirements, or to transfer ownership or operational control. Failure to comply with any of the conditions of certification or applicable LORS may result in a non-compliance report, an administrative fine, certification revocation, or any combination thereof, as appropriate. A summary of the Compliance Conditions of Certification are included as Compliance Table 1 at the end of this Compliance Plan.

COMPLIANCE ENFORCEMENT

The Energy Commission's legal authority to enforce the terms and conditions of its Decision are specified in Public Resources Code sections 25534 and 25900. The Energy Commission may amend or revoke a project certification and may impose a civil penalty for any significant failure to comply with the terms or conditions of the Decision. The Energy Commission's actions and fine assessments would take into account the specific circumstances of the incident(s).

PERIODIC COMPLIANCE REPORTING

Many of the conditions of certification require submittals in the MCRs and ACRs. All compliance submittals assist the CPM in tracking project activities and monitoring compliance with the terms and conditions of the SEP Decision. During construction, the project owner or an authorized agent will submit compliance reports on a monthly basis. During operation, compliance reports are submitted annually; though reports regarding compliance with various technical area conditions of certification may be required more often (e.g. AIR QUALITY). Further detail regarding the MCR/ACR content and the requirements for an accompanying compliance matrix are described below.

INVESTIGATION REQUESTS AND 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, sections 1230 through 1232.5, but, in many instances, the issue(s) can be resolved by using an informal dispute resolution process. Both the informal and formal complaint procedures, as described in current state law and regulations, are summarized below. Energy Commission staff will follow these provisions unless superseded by future law or regulations.[1] The California Office of Administrative Law provides on-line access to the California Code of Regulations at http://www.oal.ca.gov/.

[1] Title 20, California Code of Regulations, section 1237 (Post-Certification Complaints) was repealed effective January 2015. The new sections cited, 1230 through 1232.5, address informal and formal Requests for Investigation and Complaints.

Informal Dispute Resolution Process

The informal process specified in Title 20, California Code of Regulations, section 1230 is designed to resolve code and compliance interpretation disputes stemming from the project's conditions of certifications and other LORS. The project owner, the Energy Commission, or any other party, including members of the public, may initiate the informal dispute resolution process. Disputes may pertain to actions or decisions made by any party, including the Energy Commission's delegate agents.

This process may precede the formal complaint and investigation procedure specified in Title 20, California Code of Regulations, section 1231, but is not intended to be a prerequisite or substitute for it. This informal procedure may not be used to change the terms and conditions of certification in the Decision, although the agreed-upon resolution may result in the project owner proposing an amendment. The informal dispute resolution process encourages all parties to openly discuss the conflict and reach a mutually agreeable solution. If a dispute cannot be resolved, then the matter must be brought before the full Energy Commission for consideration via the complaint and investigation procedure specified in Title 20, California Code of Regulations, section 1231.

Request for Informal Investigation

Any person or agency may request that the CPM conduct an informal investigation of alleged noncompliance with the Energy Commission's conditions of certification. Upon receipt of an informal investigation request, the CPM will promptly provide both verbal and written notification to the project owner of the allegation(s), along with all known and relevant information of the alleged noncompliance. The CPM will evaluate the request and, if the CPM determines that further investigation is necessary, will ask the project owner to promptly conduct a formal inquiry into the matter and provide a written report of the investigation results within seven (7) days, along with corrective measures proposed or undertaken. Depending on the urgency of the matter, the CPM may conduct a site visit and/or request that the project owner provide an initial verbal report within 48 hours.

Request for Informal Meeting

In the event that either the requesting party or Energy Commission staff are not satisfied with the project owner's investigative report or corrective measures, either party may submit a written request to the CPM for a meeting with the project owner. The request shall be made within 14 days of the project owner's filing of the required investigative report. Upon receipt of such a request, the CPM will attempt to:

1. immediately schedule a meeting with the requesting party and the project owner, to be held at a mutually convenient time and place;

2. secure the attendance of appropriate Energy Commission staff and staff of any other agencies with expertise in the subject area of concern, as necessary; and
3. conduct the meeting in an informal and objective manner so as to encourage the voluntary settlement of the dispute in a fair and equitable manner.

After the meeting, the CPM will promptly prepare and distribute copies to all parties and to the project file, of a summary memorandum that fairly and accurately identifies the positions of all parties and any understandings reached. If no agreement was reached, the CPM will direct the complainant to the formal complaint process provided under Title 20, California Code of Regulations, section 1231.

Any person may file a complaint with the Energy Commission's Dockets Unit alleging noncompliance with a Commission Decision adopted pursuant to Public Resources Code section 25500. Requirements for complaint filings and a description of how complaints are processed are provided in Title 20, California Code of Regulations, section1231.

POST-CERTIFICATION CHANGES TO THE ENERGY COMMISSION DECISION

The project owner must petition the Energy Commission pursuant to Title 20, California Code of Regulations, section 1769, to modify the design, operation, or performance requirements of the project and/or the linear facilities, or to transfer ownership or operational control of the facility. It is the responsibility of the project owner to contact the CPM to determine if a proposed project change should be considered a project modification pursuant to section 1769, and the CPM will determine whether staff approval will be sufficient, or whether Energy Commission approval will be necessary.

A project owner is required to submit a five thousand ($5,000) dollar fee for every Petition to Amend a previously certified facility, pursuant to Public Resources Code section 25806(e). If the actual amendment processing costs exceed $5,000.00, the total Petition to Amend reimbursement fees owed by a project owner will not exceed the maximum filing fee for an AFC, which is seven hundred fifty thousand dollars ($750,000), adjusted annually. Implementation of a project modification without first securing Energy Commission approval may result in an enforcement action including civil penalties in accordance with Public Resources Code, section 25534.

Below is a summary of the criteria for determining the type of approval process required, reflecting the provisions of Title 20, California Code of Regulations, section 1769, at the time this compliance plan was drafted. If the Energy

Commission modifies this regulation, the language in effect at the time of the requested change shall apply. Upon request, the CPM can provide sample formats of these submittals.

AMENDMENT

The project owner shall submit a Petition to Amend the Energy Commission Decision, pursuant to Title 20, California Code of Regulations, section 1769 (a), when proposing modifications to the design, operation, or performance requirements of the project and/or the linear facilities. If a proposed modification results in an added, changed, or deleted condition of certification, or makes changes causing noncompliance with any applicable LORS, the petition will be processed as a formal amendment to the Decision, triggering public notification of the proposal, public review of the Energy Commission staff's analysis, and consideration of approval by the full Energy Commission.

CHANGE OF OWNERSHIP AND/OR OPERATIONAL CONTROL

Change of ownership or operational control also requires that the project owner file a petition pursuant to section 1769 (b). This process requires public notice and approval by the full Energy Commission, but does not require submittal of an amendment processing fee.

STAFF-APPROVED PROJECT MODIFICATION

Modifications that do not result in additions, deletions, or changes to the conditions of certification, that are compliant with the applicable LORS, and that will not have significant environmental impacts, may be authorized by the CPM as a staff-approved project modification pursuant to section 1769 (a)(2). Once the CPM files a Notice of Determination of the proposed project modifications, any person may file an objection to the CPM's determination within 14 days of service on the grounds that the modification does not meet the criteria of section 1769 (a)(2). If there is a valid objection to the CPM's determination, the petition must be processed as a formal amendment to the Decision and must be considered for approval by the full Energy Commission at a publically noticed Business Meeting or hearing.

VERIFICATION CHANGE

Pursuant to section 1770(e), a verification may be modified by the CPM, after giving notice to the project owner, if the change does not conflict with any condition of certification.

EMERGENCY RESPONSE CONTINGENCY PLANNING AND INCIDENT REPORTING

To protect public health and safety and environmental quality, the conditions of certification include contingency planning and incident reporting requirements to

ensure compliance with necessary health and safety practices. A well-drafted contingency plan avoids or limits potential hazards and impacts resulting from serious incidents involving personal injury, hazardous spills, flood, fire, explosions or other catastrophic events and ensures a comprehensive timely response. All such incidents must be reported immediately to the CPM and documented. These requirements are designed to build from "lessons learned," limit the hazards and impacts, anticipate and prevent recurrence, and provide for the safe and secure shutdown and re-start of the facility.

FACILITY CLOSURE

The Energy Commission cannot reasonably foresee all potential circumstances in existence when a facility permanently closes. Therefore, the closure conditions provided herein strive for the flexibility to address circumstances that may exist at some future time. Most importantly, facility closure must be consistent with all applicable Energy Commission conditions of certification and the LORS in effect at that time.

Prior to submittal of the facility's Final Closure Plan to the Energy Commission, the project owner and the CPM will hold a meeting to discuss the specific contents of the plan. In the event that significant issues are associated with the plan's approval, the CPM will hold one or more workshops and/or the Energy Commission may hold public hearings as part of its approval procedure.

With the exception of measures to eliminate any immediate threats to public health and safety or to the environment, facility closure activities cannot be initiated until the Energy Commission approves the Final Closure Plan and Cost Estimate, and the project owner complies with any requirements the Energy Commission may incorporate as conditions of approval of the Final Closure Plan.

COMPLIANCE CONDITIONS OF CERTIFICATION

For the SEP project, staff proposes the **Compliance** Conditions of Certification below. Changes from the 2005 Commission Decision are shown in ~~strikethrough~~ for deleted text and **bold underline** for new text.

The language of **COM-1** through **COM-7** have been updated had been updated to reflect new definitions and compliance enforcement policies. The new **COM-8** replaces the previous **COM-9**, and the new **COM-9** replaces the previous **COM-10**. The new **COM-10** has been updated with Compliance Plan information pertaining to Amendments, Staff-Approved Project Modification, Ownership changes, and Verification Changes. **COM-11** has been updated to incorporate a number of administrative changes to reporting complaints, notices and citations. **COM-12** (Emergency Response Site Contingency Plan), is a new condition requiring a Contingency Plan for emergency response for a number of foreseeable emergency events. **COM-13** (Incident-Reporting Requirements) is also a new condition requiring the project owner to notify the CPM within one hour of any serious event, as defined by the condition, occur. **COM-14** (Non-Operation) and **COM-15** (Facility Closure Planning) replace previous Compliance Plan information pertaining to Facility Closure, unplanned temporary and unplanned permanent.

COM-1 **Unrestricted Access.** **The project owner shall take all steps necessary to ensure that** ~~T~~**t**he CPM, responsible Energy Commission staff, and delegate agencies or consultants~~, shall be guaranteed and granted~~ **have** unrestricted access to the ~~power plant~~ **facility** site, related facilities, project-related staff, and the ~~files and~~ records maintained on**-**site for the purpose of conducting **to facilitate** audits, surveys, inspections, or general **or closure-related** site visits. Although the CPM will normally schedule site visits on dates and times agreeable to the project owner, the CPM reserves the right to make unannounced visits at any time**, whether such visits are by the CPM in person or through representatives from Energy Commission staff, delegated agencies, or consultants.**

COM-2 **Compliance Record**. The project owner shall maintain **electronic copies of all** project files **and submittals** on-site, or at an alternative site approved by the CPM, for the **operational** life **and closure** of the project. ~~unless a lesser period of time is specified by the conditions of certification.~~ The files shall **also at least one hard copy of**: ~~contain copies of all "as-built" drawings, all documents submitted as verification for conditions, and all other project-related documents.~~

1. the facility's Application for Certification;

2. all amendment petitions and Energy Commission orders;

3. all site-related environmental impact and survey documentation;

4. all appraisals, assessments, and studies for the project;

5. all finalized original and amended structural plans and "as-built" drawings for the entire project;

6. all citations, warnings, violations, or corrective actions applicable to the project, and

7. the most current versions of any plans, manuals, and training documentation required by the conditions of certification or applicable LORS.

Energy Commission staff and delegate agencies shall, upon request to the project owner, be given unrestricted access to the files maintained pursuant to this condition.

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 lead times associated with the start of construction may require the project owner to file submittals during the amendment process, particularly if construction is planned to commence shortly after certification. The verification procedures, unlike the conditions, may be modified as necessary by the CPM after notice to the project owner.**

~~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 **an** 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~~ **project by AFC number, cite the appropriate condition of certification number(s), and give** 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 **and the condition(s) of certification applicable**.

All reports and plans required by the project's conditions of certification shall be submitted in a searchable electronic format (.pdf, MS Word or Excel, etc.) and include standard formatting elements such as a table of contents identifying by title and page number each section, table, graphic, exhibit, or addendum. All report and/or plan graphics and maps shall be adequately scaled and shall include a key with descriptive labels, directional headings, a bar scale, and the most recent revision date.

The project owner is responsible for the **content and** delivery and content of all verification submittals to the CPM, ~~whether such condition was~~ **the actions required by the verification were** satisfied by ~~work performed by~~ the project owner or an agent of the project owner. All submittals shall be **accompanied by an electronic copy on an electronic storage medium, or by e-mail, as agreed upon by the CPM. If hard copy submittals are required, please** addressed as follows:

~~Steve Munro (or successor)~~
Compliance Project Manager
Sonoran Energy Project (02-AFC-1C)
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 its 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, **the project owner shall submit to the CPM** a compliance matrix ~~addressing~~ **including** only those conditions that must be fulfilled before the start of construction ~~shall be submitted by the project owner to the CPM~~. Th**e**~~is~~ matrix ~~will~~ **shall** be included with the project owner's first compliance submittal **or prior to the first pre-construction meeting, whichever comes first**, and shall be submitted **in a format similar to the description below.**~~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 pre-certification approval by Energy Commission staff is subject to change based upon the Final Decision.~~

Site mobilization and construction activities shall not start until the following have occurred:

1. **The project owner has submitted the pre-construction matrix and all compliance verifications pertaining to pre-construction conditions of certification; and**

2. **The CPM has issued an authorization-to-construct letter to the project owner.**

The deadlines for submitting various compliance verifications to the CPM allow staff sufficient time to review and comment on, and, if necessary, also allow the project owner to revise the submittal in a timely manner. These procedures help ensure that project construction proceeds according to schedule. Failure to submit required compliance documents by the specified deadlines may result in delayed authorizations to commence various stages of the project.

If the project owner anticipates site mobilization immediately following project certification, it may be necessary for the project owner to file compliance submittals prior to project certification. In these instances, compliance verifications can be submitted in advance of the required deadlines and the anticipated authorizations to start construction. The project owner must understand that submitting compliance verifications prior to these authorizations is at the owner's own risk. Any approval by Energy Commission staff prior to project certification is subject to change based upon the Commission Decision, or amendment thereto, and early staff compliance approvals do not imply that the Energy Commission will certify the project for actual construction and operation.

~~**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**. The project owner shall submit a compliance matrix to the CPM **<u>with each MCR and ACR</u>** ~~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~~ **<u>shall</u>** identify:

1. the technical area **<u>(e.g., biological resources, facility design, etc.)</u>**;
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. **<u>if the condition was amended, the updated language and the date the amendment was proposed or approved.</u>** ~~the project’s preconstruction and construction milestones, including dates and status (if milestones are required).~~

<u>The CPM can provide a template for the compliance matrix upon request.</u> ~~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.~~

<u>COM-6</u> **<u>Monthly Compliance Report</u>**. The first ~~Monthly Compliance Report~~ **MCR** is due one month following the **<u>docketing of the project’s Decision</u>** ~~Energy Commission business meeting date on which the project was approved,~~ unless otherwise agreed to by the CPM. The first ~~Monthly Compliance Report~~ **<u>MCR</u>** shall include **<u>the AFC number and</u>** 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~~ **Compliance Plan**.)

During pre-construction**, construction, or closure,** ~~and construction of the project,~~ the project owner or authorized agent shall submit an **electronic searchable version of the MCR to the CPM** ~~original and five copies (or amount specified by Compliance Project Manager) of the Monthly Compliance Report~~ within **ten** (10) ~~working~~ **business** days after the end of each reporting month. **MCRs shall be submitted each month until construction is complete and the final certificate of occupancy is issued by the DCBO.** ~~Monthly Compliance Reports~~ **MCRs** shall be clearly identified for the month being reported. The ~~reports~~ **MCR** 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~~**MCR**. Each of these items ~~must~~**shall** be identified in the transmittal letter**, as well as the conditions they satisfy**, and ~~should be~~ submitted as attachments to the ~~Monthly Compliance Report~~**MCR**;
3. an initial, and thereafter updated, compliance matrix ~~which shows~~ **showing** the status of all conditions of certification;
4. a list of conditions that have been satisfied during the reporting period, and a description or reference to the actions ~~which~~**that** satisfied the condition;
5. a list of any submittal deadlines that were missed**,** accompanied by an explanation and an estimate of when the information will be provided;
6. a cumulative listing of any approved changes to conditions of certification;
7. a listing of any filings submitted to, ~~with, or~~**and** permits issued by, other governmental agencies during the month;
8. a projection of project compliance activities scheduled during the next **(2)** two months~~.~~**;** ~~T~~the project owner shall notify the CPM as soon as any changes are made to the project construction schedule that would affect compliance with conditions of certification;
9. a listing of the month's additions to the on-site compliance file; **and**

~~10. any requests, with justification, to dispose of items that are required to be maintained in the project owner's compliance file; and~~

10~~1~~. a listing of **incidents,** complaints, notices of violation, official warnings, and citations received during the month**; a list of any incidents that occurred during the month**, a description of the **actions taken to date to resolve the issues; and the status of any unresolved actions**

noted in the previous MCRs~~resolutions of any resolved complaints, and the status of any unresolved complaints~~.

COM-7 **Periodic and Annual Compliance Reports**. After construction is complete, the project owner ~~shall submit Annual Compliance Reports instead of Monthly Compliance Reports~~ **must submit searchable electronic ACRs to the CPM, as well as other periodic compliance reports (PCRs) required by the various technical disciplines**. ~~The reports are~~ **ACRs shall be completed** for each year of commercial operation and are due **each year** ~~to the CPM each year at~~ **on** 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~~ **Other PCRs (e.g. quarterly reports or decommissioning reports to monitor closure compliance), may be specified by the CPM. The searchable electronic copies may be filed on an electronic storage medium or by e-mail, subject to CPM approval. Each ACR must include the AFC number, identify the reporting period, and** contain the following:

1. an updated compliance matrix which shows the status of all conditions of certification (fully satisfied ~~and/or closed~~ conditions do not need to be included in the matrix after they have been reported as ~~closed~~**completed**);
2. a summary of the current project operating status and an explanation of any significant changes to facility operations during the year;
3. documents required by specific conditions to be submitted along with the ~~Annual Compliance Report~~**ACR;**~~.~~ ~~E~~**e**ach of these items ~~must~~ **shall** be identified in the transmittal letter **with the conditions it satisfies**~~,~~ and ~~should be~~ submitted as **an** attachment~~s~~ to the ~~Annual Compliance Report~~**ACR**;
4. a cumulative list~~ing~~ of all post-certification changes ~~for the year~~ 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~~**submitted** to, or permits issued by, other governmental agencies during the year;
7. a projection of project compliance activities scheduled during the next year;
8. a listing of the year's additions to the on-site compliance file;
9. an evaluation of the ~~on-s~~**S**ite ~~c~~**C**ontingency ~~p~~**P**lan**, including amendments and plan updates**~~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, **incidents,** notices of violation, official warnings, and citations received during the year, a description of **how the issues were resolved**~~the resolution of any resolved complaints~~, and the status of any unresolved complaints.

COM-8 **Confidential Information. Any information that the project owner designates as confidential shall be submitted to the Energy Commission's Executive Director with an application for confidentiality, pursuant to Title 20, California Code of Regulations, section 2505(a). Any information deemed confidential pursuant to the regulations will remain undisclosed, as provided in Title 20, California Code of Regulations, section 2501**.
~~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),~~
- ~~Department of Justice Chemical Facility Vulnerability Assessment Methodology (US DOJ 2002),~~
- ~~North American Electric Reliability Council Security Guidelines for the Electricity Sector (NAERC 2002),~~
- ~~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 **Annual Energy Facility Compliance Fee. Pursuant to the provisions of section 25806 (b) of the Public Resources Code, the project owner is required to pay an annually adjusted compliance fee. Current compliance fee information is available on the Energy Commission's website at http://www.energy.ca.gov/siting/filing_fees.html. The project owner may also contact the CPM for the current fee information. The initial payment is due on the date the Energy Commission dockets its final Decision. All subsequent payments are due by July 1 of each year in which the facility retains its certification.**

~~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 **Amendments, Staff-Approved Project Modifications, Ownership Changes, and Verification Changes. The project owner shall petition the Energy Commission, pursuant to Title 20, California Code of Regulations, section 1769, to modify the design, operation, or performance requirements of the project or linear facilities, or to transfer ownership or operational control of the facility. The CPM will determine whether staff approval will be sufficient, or whether Commission approval will be necessary. It is the project owner's responsibility to contact the CPM to determine if a proposed project change triggers the requirements of section 1769. Section 1769 details the required contents for a Petition to Amend an Energy Commission Decision. The only change that can be requested by means of a letter to the CPM is a request to change the verification method of a condition of certification.**

A project owner is required to submit a five thousand ($5,000) dollar fee for every Petition to Amend a previously certified facility, pursuant to Public Resources Code section 25806(e). If the actual amendment processing costs exceed $5,000.00, the total Petition to Amend reimbursement fees owed by a project owner will not exceed seven hundred fifty thousand dollars ($750,000), adjusted annually. Current amendment fee information is available on the Energy Commission's website at http://www.energy.ca.gov/siting/filing_fees.html.

~~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 **or closure**, the project owner ~~must~~**shall** send a letter to property owners ~~living~~ within one **(1)** mile of the project**,** notifying them of a telephone number to contact project representatives with questions, complaints or concerns. If the telephone is not staffed 24 hours per day, it ~~shall~~**must** include automatic answering with date and time stamp recording.

The project owner shall respond to all recorded complaints within 24 hours or the next business day. The project site shall post the telephone number on-site and make it easily visible to passersby during construction, operation, and closure. The project owner shall provide the contact information to the CPM and promptly report any disruption to the contact system or telephone number change to the CPM, who will provide it to any persons contacting him or her with a complaint.

Within five (5) days of receipt, the project owner shall report and provide copies to the CPM, of all complaints, (including, but not limited to, noise and lighting complaints, notices of violation, notices of fines, official warnings, and citations). Complaints shall be logged and numbered. Noise complaints shall be recorded on the form provided in the NOISE AND VIBRATION Conditions of Certification. All other complaints shall be recorded on the complaint form (Attachment A) at the end of this Compliance Plan. Additionally, the project owner must include in the next subsequent MCR, ACR or PCR, copies of all complaints, notices, warnings, citations and fines, a description of how the issues were resolved, and the status of any unresolved or ongoing matters.

~~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. All complaints shall be recorded on the complaint form (Attachment A) or an equivalent.~~

~~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~~

<u>COM-12 Emergency Response Site Contingency Plan. No less than 60 days prior to the start of construction (or other CPM-approved date), the project owner shall submit for CPM review and approval, an Emergency Response Site Contingency Plan (Contingency Plan). Subsequently, no less than 60 days prior to the start of commercial operation, the project owner shall update (as necessary) and resubmit the Contingency Plan for CPM review and approval. The Contingency Plan shall evidence a facility's coordinated emergency response and recovery preparedness for a series of reasonably foreseeable emergency events. The CPM may require Contingency Plan updating over the life of the facility. Contingency Plan elements include, but are not limited to:</u>

1. **<u>A site-specific list and direct contact information for persons, agencies, and responders to be notified for an unanticipated event;</u>**

2. **A detailed and labeled facility map, including all fences and gates, the windsock location (if applicable), the on- and off-site assembly areas, and the main roads and highways near the site;**

3. **A detailed and labeled map of population centers, sensitive receptors, and the nearest emergency response facilities;**

4. **A description of the on-site, first response and backup emergency alert and communication systems, site-specific emergency response protocols, and procedures for maintaining the facility's contingency response capabilities, including a detailed map of interior and exterior evacuation routes, and the planned location(s) of all permanent safety equipment;**

5. **An organizational chart including the name, contact information, and first aid/emergency response certification(s) and renewal date(s) for all personnel regularly on-site;**

6. **A brief description of reasonably foreseeable, site-specific incidents and accident sequences (on- and off-site), including response procedures and protocols and site security measures to maintain twenty-four-hour site security;**

7. **Procedures for maintaining contingency response capabilities; and**

8. **The procedures and implementation sequence for the safe and secure shutdown of all non-critical equipment and removal of hazardous materials and waste (see also specific conditions of certification for the technical areas of Public Health, Waste Management, Hazardous Materials Management, and Worker Safety).**

~~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 Incident-Reporting Requirements. The project owner shall notify the CPM or Compliance Office Manager, by telephone and e-mail, within one (1) hour after it is safe and feasible, upon identification of any incident at the power plant or appurtenant facilities that results or could result in any of the following:

1. **A reduction in the maximum output capability of a generating unit of at least ten (10) MW or five (5) percent, whichever is greater, that lasts for fifteen (15) minutes or longer (or such values as trigger CAISO no prior notice outage reporting requirements under any subsequent modifications to CAISO tariff 9.3.10.3.1); facility's ability to respond to dispatch (excluding forced outages cause by protective equipment or other typically encountered shutdown events);**

2. **Potential health impacts to the surrounding population or any release that could result in an off-site odor issue;**

3. **Notification to or response by any off-site emergency response, federal, state or local agency regarding a fire, hazardous materials release, on-site injury, or any physical or cyber security incident.**

The notice shall describe the circumstances, status, and expected duration of the incident. If warranted, as soon as it is safe and feasible, the project owner shall implement the safe shutdown of any non-critical equipment and removal of any hazardous materials and waste that pose a threat to public health and safety and to environmental quality (also, see specific conditions of certification for the technical areas of Hazardous Materials Management and Waste Management).
Within one (1) week of the incident, the project owner shall submit to the CPM a detailed incident report, which includes, as appropriate, the following information:

4. **a brief description of the incident, including its date, time, and location;**
5. **a description of the cause of the incident, or likely causes if it is still under investigation;**
6. **the location of any off-site impacts;**
7. **description of any resultant impacts;**
8. **a description of emergency response actions associated with the incident;**
9. **identification of responding agencies;**
10. **identification of emergency notifications made to federal, state, and/or local agencies;**
11. **identification of any hazardous materials released and an estimate of the quantity released;**
12. **a description of any injuries, fatalities, or property damage that occurred as a result of the incident;**
13. **fines or violations assessed or being processed by other agencies;**
14. **name, phone number, and e-mail address of the appropriate facility contact person having knowledge of the event; and**
15. **corrective actions to prevent a recurrence of the incident.**

The project owner shall maintain all incident report records for the life of the project, including closure. After the submittal of the initial report for any incident, the project owner shall submit to the CPM copies of incident reports within 24 hours of a request.

~~**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 Non-Operation and Repair/Restoration Plans. If the facility ceases operation temporarily (excluding planned maintenance), for longer than one (1) week (or other CPM-approved date), but less than three (3) months (or other CPM-approved date), the project owner shall notify the CPM, interested agencies, and nearby property owners. Notice of planned non-operation shall be given at least two (2) weeks prior to the scheduled date. Notice of unplanned non-operation shall be provided no later than one (1) week after non-operation begins.

For any non-operation, a Repair/Restoration Plan for conducting the activities necessary to restore the facility to availability and reliable and/or improved performance shall be submitted to the CPM within one (1) week after notice of non-operation is given. If non-operation is due to an unplanned incident, temporary repairs and/or corrective actions may be undertaken before the Repair/Restoration Plan is submitted. The Repair/Restoration Plan shall include:

1. **Identification of operational and non-operational components of the plant;**
2. **A detailed description of the repair and inspection or restoration activities;**
3. **A proposed schedule for completing the repair and inspection or restoration activities;**
4. **An assessment of whether or not the proposed activities would require changing, adding, and/or deleting any conditions of certification, and/or would cause noncompliance with any applicable LORS; and**
5. **Planned activities during non-operation, including any measures to ensure continued compliance with all conditions of certification and LORS.**

Written monthly updates (or other CPM-approved intervals) to the CPM for non-operational periods, until operation resumes, shall include:

1. **Progress relative to the schedule;**
2. **Developments that delayed or advanced progress or that may delay or advance future progress;**
3. **Any public, agency, or media comments or complaints; and**
4. **Projected date for the resumption of operation.**

During non-operation, all applicable conditions of certification and reporting requirements remain in effect. If, after one (1) year from the date of the project owner's last report of productive Repair/Restoration Plan work, the facility does not resume operation or does not provide a

plan to resume operation, the Executive Director may assign suspended status to the facility and recommend commencement of permanent closure activities. Within 90 days of the Executive Director's determination, the project owner shall do one of the following:

1. **If the facility has a closure plan, the project owner shall update it and submit it for Energy Commission review and approval.**
2. **If the facility does not have a closure plan, the project owner shall develop one consistent with the requirements in this Compliance Plan and submit it for Energy Commission review and approval.**

~~**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.~~

COM-15: Facility Closure Planning. To ensure that a facility's eventual permanent closure and long-term maintenance do not pose a threat to public health and safety and/or to environmental quality, the project owner shall coordinate with the Energy Commission to plan and prepare for eventual permanent closure.

A. Provisional Closure Plan

To assure satisfactory long-term site maintenance and adequate closure for "the whole of a project," the project owner shall include within the first ACR a Provisional Closure Plan for CPM review and approval. The CPM may require Provisional Closure Plan updates to reflect project-modifications approved by the Energy Commission. The Provisional Closure Plan shall consider applicable final closure plan requirements, including interim and long-term maintenance costs and reflect that qualified personnel will carry out permanent closure and long-term maintenance activities.

The Provisional Closure Plan shall reflect the most current regulatory standards, best management practices, and applicable LORS, and provide for a phased closure process and include but not be limited to:

1. **comprehensive scope of work;**
2. **dismantling and demolition;**
3. **recycling and site clean-up;**
4. **mitigation and monitoring direct, indirect, and cumulative impacts;**
5. **site remediation and/or restoration;**
6. **interim and long-term operation monitoring and maintenance, including long-term equipment replacement costs; and**
7. **contingencies.**

B. Final Closure Plan and Cost Estimate

No less than one (1) year (or other CPM-approved date) prior to initiating a permanent facility closure, the project owner shall submit for Energy Commission review and approval, a Final Closure Plan and Cost Estimate, which includes any long-term, site maintenance and monitoring.

Prior to submittal of the facility's Final Closure Plan to the Energy Commission, the project owner and the CPM will hold a meeting to discuss the specific contents of the plan. In the event that significant issues are associated with the plan's approval, the CPM will hold one

or more workshops and/or the Energy Commission may hold public hearings as part of its approval procedure.

Final Closure Plan and Cost Estimate contents include, but are not limited to:

1. **a statement of specific Final Closure Plan objectives;**
2. **a statement of qualifications and resumes of the technical experts proposed to conduct the closure activities, with detailed descriptions of previous power plant closure experience;**
3. **identification of any facility-related installations or maintenance agreements not part of the Energy Commission certification, designation of who is responsible for these, and an explanation of what will be done with them after closure;**
4. **a comprehensive scope of work and itemized budget for permanent plant closure and long-term site maintenance activities, with a description and explanation of methods to be used, broken down by phases, including, but not limited to:**
   a. **dismantling and demolition;**
   b. **recycling and site clean-up;**
   c. **impact mitigation and monitoring;**
   d. **site remediation and/or restoration, including ongoing testing or monitoring protocols,**
   e. **exterior maintenance, including paint, landscaping and fencing,**
   f. **site security and lighting, and**
   g. **any contingencies.**
5. **a Final Cost Estimate for all closure activities, by phases, including long-term site monitoring and maintenance costs, and long-term equipment replacement;**
6. **a schedule projecting all phases of closure activities for the power plant site and all appurtenances constructed as part of the Energy Commission-certified project;**
7. **an electronic submittal package of all relevant plans, drawings, risk assessments, and maintenance schedules and/or reports, including an above- and below-ground infrastructure inventory map and registered engineer's or DCBO's assessment of demolishing the facility; additionally, for any facility that permanently ceased operation prior to submitting a Final Closure Plan and Cost Estimate and for which only minimal or**

no maintenance has been done since, a comprehensive condition report focused on identifying potential hazards;

8. **all information additionally required by the facility's conditions of certification applicable to plant closure;**
9. **an equipment disposition plan, including:**
   a. **recycling and disposal methods for equipment and materials; and**
   b. **identification and justification for any equipment and materials that will remain on-site after closure;**
10. **a site disposition plan, including but not limited to:**
    a. **proposed rehabilitation, restoration, and/or remediation procedures, as required by the conditions of certification and applicable LORS, and long-term site maintenance activities.**
11. **identification and assessment of all potential direct, indirect, and cumulative impacts and proposal of mitigation measures to reduce significant adverse impacts to a less-than-significant level; potential impacts to be considered shall include, but not be limited to:**
    a. **traffic;**
    b. **noise and vibration;**
    c. **soil erosion;**
    d. **air quality degradation;**
    e. **solid waste;**
    f. **hazardous materials;**
    g. **waste water discharges, and**
    h. **contaminated soil.**
12. **identification of all current conditions of certification, LORS, federal, state, regional, and local planning efforts applicable to the facility, and proposed strategies for achieving and maintaining compliance during closure;**
13. **updated mailing list and Listserv of all responsible agencies, potentially interested parties, and property owners within one (1) mile of the facility;**
14. **identification of alternatives to plant closure and assessment of the feasibility and environmental impacts of these; and**
15. **description of and schedule for security measures and safe shutdown of all non-critical equipment and removal of hazardous materials and waste (see conditions of certification**

for Public Health, Waste Management, Hazardous Materials Management, and Worker Safety).

If the Energy Commission-approved Final Closure Plan and Cost Estimate are not initiated within one (1) year of its approval date, it shall be updated and re-submitted to the Energy Commission for supplementary review and approval. If a project owner initiates but then suspends closure activities, and the suspension continues for longer than one (1) year, the Energy Commission may initiate correction actions against the project owner to complete facility closure. The project owner remains liable for all costs of contingency planning and closure.

~~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 delete or change a condition of certification, 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~~
~~A proposed project modification will be processed as an amendment if it alters the intent or purpose of a condition of certification, has potential for significant adverse environmental impact, or may violate applicable laws, ordinances, regulations or standards. The full Commission must approve formal amendments. The project owner shall file a petition in accordance with Title 20, California Code of Regulations, section 1769 (a).~~

~~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~~

~~If a proposed modification does not alter the intent or purpose of a condition of certification, does not have potential for significant adverse environmental impact, does not violate applicable laws, ordinances, regulations, or standards, or does not result in an ownership change, it will be processed in accordance with Section 1769(a)(2). In this regard, as specified in Section 1769(a)(2), Commission approval is not required.~~

~~The CPM shall file a statement that staff has made such a determination with the Commission Docket and mail a copy of the statement to every person on the project's post- certification mailing list.~~

~~Any person may file an objection to staff's determination within 14 days of service on the grounds that the modification does not meet the criteria in section 1769 (a)(2). If an objection is received, the petition must be processed as a formal amendment to the final decision and must be approved by the full Commission at a noticed business meeting or hearing.~~

~~Verification Change~~
~~A verification may be modified by the CPM without requesting an amendment to the decision if the change does not conflict with intent or purpose of the conditions of certification and provides an effective alternate means of verification.~~

KEY EVENTS LIST

PROJECT: ____________________

DOCKET #: ____________________

COMPLIANCE PROJECT MANAGER: ____________________

EVENT DESCRIPTION	DATE
Certification Date	
Obtain Site Control	
On-line Date	
POWER PLANT SITE ACTIVITIES	
Start Site Assessment/Pre-construction	
Start Site Mobilization/Construction	
Begin Pouring Major Foundation Concrete	
Begin Installation of Major Equipment	
Completion of Installation of Major Equipment	
First Combustion of Turbine	
Obtain Building Occupation Permit	
Start Commercial Operation	
Complete All Construction	
TRANSMISSION LINE ACTIVITIES	
Start Transmission Line Construction	
Complete Transmission Line Construction	
Synchronization with Grid and Interconnection	
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	
Start Recycled Water Supply Line Construction	
Complete Recycled Water Supply Line Construction	

Compliance Table 1:
Summary of Compliance Conditions of Certification

Condition Number	Subject	Description
COM-1	Unrestricted Access	The project owner shall grant Energy Commission staff and delegate agencies or consultants unrestricted access to the power plant site.
COM-2	Compliance Record	The project owner shall maintain project files on-site. Energy Commission staff and delegate agencies shall be given unrestricted access to the files.
COM-3	Compliance Verification Submittals	The project owner is responsible for the delivery and content of all verification submittals to the CPM, regardless of whether the conditions were satisfied directly by the project owner or by an agent.
COM-4	Pre-construction Matrix and Tasks Prior to Start of Construction	Construction shall not commence until the all of the following activities/submittals have been completed: • Project owner has submitted a pre-construction matrix identifying conditions to be fulfilled before the start of construction; • Project owner has completed all pre-construction conditions to the CPM's satisfaction; and • CPM has issued a letter to the project owner authorizing construction.
COM-5	Compliance Matrix	The project owner shall submit a compliance matrix (in a spreadsheet format) with each Monthly and Annual Compliance Report, which includes the current status of all Compliance Conditions of Certification.
COM-6	Monthly Compliance Reports and Key Events List	During construction, the project owner shall submit Monthly Compliance Reports (MCRs) which include specific information. The first MCR is due one (1) month following the docketing of the Energy Commission's Decision on the project and shall include an initial list of dates for each of the events identified on the Key Events List.
COM-7	**Periodic and** Annual Compliance Reports	After construction ends, and throughout the life of the project, the project owner shall submit Annual Compliance Reports (ACRs) instead of MCRs.
COM-8	Confidential Information	Any information the project owner designates as confidential shall be submitted to the Energy Commission's Executive Director with a request for confidentiality.
COM-9	Annual Fees	Required payment of the Annual Energy Facility Compliance Fee.
COM-10	Amendments, Staff-Approved Project Modifications, Ownership Changes, and Verification Changes	The project owner shall petition the Energy Commission to delete or change a condition of certification, modify the project design or operational requirements, and/or transfer ownership or operational control of the facility. Petitions to Amend require the payment of amendment processing fees.
COM-11	Reporting of Complaints, Notices, and Citations	Prior to the start of construction, the project owner shall provide all property owners within a one-mile radius a telephone number to contact project representatives with questions, complaints, or concerns. The project owner shall respond to all recorded complaints within 24 hours. Within ten days of receipt, the project owner shall report to the CPM all notices, complaints, violations, and citations.

Compliance Table 1:
Summary of Compliance Conditions of Certification

Condition Number	Subject	Description
COM-12	Site Contingency Plan	No less than 60 days prior to the start of commercial operation, the project owner shall submit an on-site Contingency Plan to ensure protection of public health and safety and environmental quality during a response to an emergency.
COM-13	Incident-Reporting Requirements	The project owner shall notify the CPM within one (1) hour of an incident and submit a detailed incident report within (1) one week, maintain records of incident report, and submit public health and safety documents with employee training provisions.
COM-14	Non-Operation	No later than two (2) weeks prior to a facility's planned non-operation, or no later than one (1) week after the start of unplanned non-operation, the project owner shall notify the CPM, interested agencies and nearby property owners of this status. During non-operation, the project owner shall provide written updates to the CPM.
COM-15	Facility Closure Planning	Within the first ACR, the project owner shall submit a Provisional Closure Plan for permanent closure. No less than one (1) year prior to closing, the project owner shall submit a Final Closure Plan and Cost Estimate.

ATTACHMENT A
COMPLAINT REPORT AND RESOLUTION FORM

COMPLAINT LOG NUMBER:________________________________ DOCKET NUMBER:____________

PROJECT AME:____

COMPLAINANT INFORMATION

NAME:____ PHONE NUMBER:______________________________

ADDRESS:____

COMPLAINT

DATE COMPLAINT RECEIVED:_________________________ TIME COMPLAINT RECEIVED:____________________

COMPLAINT RECEIVED BY: __________________________ ☐ TELEPHONE ☐ IN WRITING (COPY ATTACHED)

DATE OF FIRST OCCURRENCE:_______________________

DESCRIPTION OF COMPLAINT (INCLUDING DATES, FREQUENCY, AND DURATION):__________________________

____

____

FINDINGS OF INVESTIGATION BY PLANT PERSONNEL:____

____

____

DOES COMPLAINT RELATE TO VIOLATION OF A CEC REQUIREMENT? ☐ YES ☐ NO

DATE COMPLAINANT CONTACTED TO DISCUSS FINDINGS:____

DESCRIPTION OF CORRECTIVE MEASURES TAKEN OR OTHER COMPLAINT RESOLUTION:___________________

____

____

DOES COMPLAINANT AGREE WITH PROPOSED RESOLUTION? ☐ YES ☐ NO

IF NOT, EXPLAIN:____

____

CORRECTIVE ACTION

IF CORRECTIVE ACTION NECESSARY, DATE COMPLETED:____

DATE FIRST LETTER SENT TO COMPLAINANT (COPY ATTACHED):_______________________________________

DATE FINAL LETTER SENT TO COMPLAINANT (COPY ATTACHED):_______________________________________

OTHER RELEVANT INFORMATION:____

____

____

"This information is certified to be correct."

PLANT MANAGER SIGNATURE:____ DATE:_______________

(ATTACH ADDITIONAL PAGES AND ALL SUPPORTING PHOTO/DOCUMENTATION, AS REQUIRED)

SONORAN ENERGY PROJECT (02-AFC-1C)
PRELIMINARY STAFF ASSESSMENT
PREPARATION TEAM

Executive Summary .... Mary Dyas

Introduction .... Mary Dyas

Project Description .... Mary Dyas

Environmental Assessment

Air Quality .... Tao Jiang Ph.D., P.E.

Biological Resources .... Andrea Martine

Cultural Resources .... Diana T. Dyste / Thomas Gates

Hazardous Materials Management .... Brett Fooks

Land Use .... Steven Kerr

Noise and Vibration .... Edward Brady

Public Health .... Obed Odoemelam, Ph.D.

Socioeconomics .... Ellen LeFevre

Soil and Water Resources .... Mike Conway, P.G.

Traffic and Transportation .... Michael C. Baron / James Adams

Transmission Line Safety and Nuisance .... Obed Odoemelam, Ph.D

Visual Resources .... Jeff Juarez

Waste Management .... Ellie Townsend-Hough

Worker Safety and Fire Protection .... Brett Fooks

Engineering Assessment

Facility Design .... Shahab Khoshmashrab

Geology and Paleontology .... Mike Conway, P.G.

Power Plant Efficiency .... Edward Brady

Power Plant Reliability .... Edward Brday

Transmission System Engineering .... Ajoy Guha / Mark Hesters

Alternatives .... Steve Kerr / David Vidiver

Compliance Conditions .... Mary Dyas

Project Assistant .... Cathy Hickman