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HUNTINGTON BEACH ENERGY PROJECT

Preliminary Staff Assessment for the Petition to Amend the Huntington Beach Energy Project Decision

CALIFORNIA
ENERGY COMMISSION
Edmund G. Brown, Jr, Governor

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John Heiser, AICP

INTRODUCTION

This Preliminary Staff Assessment (PSA) is a publication by California Energy Commission staff for the Huntington Beach Energy Project (HBEP) Petition to Amend (PTA).

On September 4, 2015, AES Huntington Beach Energy, LLC, submitted a petition to amend the final decision (12-AFC-02C). The requested amendment to the HBEP Final Decision (Decision) is the result of the selection by Southern California Edison (SCE) of the revised AES project in the 2013 Local Capacity Requirements Request for offers to provide 644-megawatt (MW) of nominal capacity, with different technology than that permitted in the HBEP Final Decision.

The PTA proposes to modify the previously approved 939- MW power plant to a new configuration that would total 844 MW. Construction would commence in two phases with the first phase consisting of a natural gas-fired, combined-cycle, air-cooled, 644-MW electrical generating facility. After the first phase combined-cycle power block is operational, phase two would begin with adding two 100-MW simple-cycle gas turbines (SCGT). No new offsite linear facilities are proposed as part of this project.

If the Amended HBEP is approved by the Energy Commission, construction and demolition activities at the project site are anticipated to take approximately 10 years, lasting through the fourth quarter of 2025. The PTA indicates a construction schedule for the various phases of activities with the combined-cycle, gas turbine (CCGT) phase I, power block 1, anticipated to begin in the second quarter of 2017 with commercial operation of power block 1 during the second quarter of 2020. Existing units 3 &4 would then be demolished. Construction of the SCGT phase 2, power block 2, is anticipated to begin during the first quarter of 2022 with commercial operation during the first quarter of 2024. Existing units 1 & 2 would then be demolished.

The project site is located on 30 acres in Huntington Beach, California at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (Highway 1) and Newland Street, and is the site of the existing Huntington Beach Generating Station. The site is privately owned land and is relatively flat with an approximate elevation of 10 to 14 feet above mean sea level. The project borders a manufactured home/recreational vehicle park on the west, a tank farm on the north, the Magnolia Marsh wetlands on the north and east, and the Pacific Ocean and Huntington Beach State Park on the south and southwest.

ENERGY COMMISSION AMENDMENT REVIEW PROCEDURES

Approval for a thermal power plant with a generating capacity of 50 MW or greater falls under the regulatory oversight of the Energy Commission (Pub. Resources Code § 25500, et seq.). As such, the Energy Commission is the lead 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 project's engineering design, evaluates its potential effects on the environment and on public health and safety, and considers environmental justice populations, and determines whether the project is in conformance with all applicable local, state, and federal laws, ordinances, regulations and standards (LORS). LORS compliance and determinations of key federal Clean Air Act and Clean Water Act requirements are made by staff's active coordination with, and incorporation of, other regulatory agencies and their findings (such as the South Coast Air Quality Management District and its Preliminary Determination of Compliance). The result of staff's research, collaboration and comprehensive process of discovery and analysis are recommendations for mitigation requirements to mitigate any significant adverse environmental effects resulting from the proposed HBEP project and the demolition activities removing the existing turbines and associated equipment.

Following publication of this PSA, there will be a 30-day comment period. Agencies, intervenors, and the public are invited to submit comments on staff's analyses of project impacts and the proposed conditions of certification designed to mitigate those significant impacts on the environment, public health, and the transmission system from the proposed construction and operation of the project and the demolition activities.

Staff will publish a Final Staff Assessment that will serve as staff's testimony in evidentiary hearings conducted by a Committee of two commissioners overseeing the proceeding. Following the issuance of the Presiding Member's Proposed Decision by the Committee, a public hearing for the purpose of approving, denying, or modifying the amendment proposal will be held at a regularly scheduled Energy Commission business meeting.

PUBLIC AND AGENCY COORDINATION AND OUTREACH EFFORTS

PUBLIC AND AGENCY NOTICE AND OUTREACH

On September 18, 2015, the Energy Commission staff sent a notice of receipt and a copy of the HBEP PTA to all local, state, and federal agencies that might be affected by the proposed project, and included information on how agencies that administer LORS that are applicable to the proposed project can comment and participate in the proceeding.

Additionally, on October 30, 2015, Energy Commission staff provided notices to property owners within 1,000 feet of the proposed site and within 500 feet of a linear facility (such as transmission lines, gas lines and water lines). These notices informed the public of the Commission's receipt and availability of the amended AFC, discussed the Energy Commission's siting certification process, provided information on how the public can comment and participate in the proceeding, as well as provided a brief description of the project, and a link to a Commission-maintained project website (http://www.energy.ca.gov/sitingcases/huntington_beach_energy/index.html).

Libraries

On November 5, 2015, the Energy Commission staff also sent copies of the Huntington Beach Energy Project AFC to the following libraries:

Huntington Beach Public Library
7111 Talbert Avenue
Huntington Beach, CA 92648

Orange County Public Library HQ
1501 E Street Andrew Place
Santa Ana, CA 92705

Costa Mesa/Donald Dungan Library
1855 Park Avenue
Costa Mesa, CA 92627

Costa Mesa/Mesa Verde Library
2969 Mesa Verde Drive
Costa Mesa, CA 92626

Mary Wilson Library
707 Electric Avenue
Seal Beach, CA 90740

Fountain Valley Library
17635 Los Alamos
Fountain Valley, CA 92708

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

Energy Commission's Public Adviser's Office

The Energy Commission's outreach program is also facilitated by the Public Adviser's Office (PAO). The PAO requested public service announcements at a variety of organizations, distributed notices informing the public of the Commission's receipt of the HBEP Amended AFC, and invited the public to attend the Public Site Visit, Environmental Scoping Meeting and Informational Hearing on December 8, 2015 in Huntington Beach, California.

Public Workshops

Staff from the Energy Commission conducted a public workshop in Huntington Beach, California to facilitate public, agency, and intervenor participation. The workshop allowed a transparent and comprehensive discussion of technical areas related to the proposed project. A Data Request and Response Workshop was held on December 8, 2015. During the workshop and scoping meeting, specific time for public participation was allocated, and public comments were taken. This workshop provided a public forum for the applicant, the intervenors, staff and participating agencies to interact regarding project issues.

Consultation with Local Native American Communities

Energy Commission staff sent written correspondence to the Native American Heritage Commission, as well as to a number of Native American tribes who have expressed an interest in being contacted about development projects in the HBEP area. This correspondence served as an invitation for tribes to consult on the project.

For the ease of the reader, this PSA provides a description of the environmental setting of the entire project. Specific details of the project are explained in the **PROJECT DESCRIPTION** and other technical sections of this PSA. A summary of the HBEP components is provided below:

- One CCGT, 644-MW power block consisting of two General Electric (GE) Frame 7FA.05s;
- Proposed stack height of 150 feet for the GE Frame 7FA.05 combustion-turbine generator units;
- Two unfired heat-recovery steam generators equipped with two emission control systems to control CO, NOx and VOC emissions;
- One steam turbine generator;
- One air-cooled condenser (ACC) and one closed-loop air-cooled heat exchanger;
- One natural gas-fired auxiliary boiler to support the power block;
- Related ancillary equipment;
- In phase two, two GE simple-cycle LMS-100 PB SCTGs with a nominal capacity of 200 MWs; and
- Proposed stack height of 80 feet for the LMS100 units.

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. Rather, the PSA is a precursor to the Final Staff Assessment (FSA) which will serve as staff's testimony during evidentiary hearings to be held by an assigned Committee of two Energy Commissioners (Commissioner Andrew McAllister the Presiding Member, and Commissioner Karen Douglas the Associate Member . During evidentiary hearings, the Committee will consider testimony, comment, and input provided and presented by staff, the applicant, intervenors, governmental agencies, and the public. The Committee will then engage in deliberation and review of the record before writing and submitting the Presiding Member's Proposed Decision for a 30-day public comment period and then to the full Energy Commission for consideration and action. Following a public hearing, most likely during a monthly Business Meeting, the full Commission will make a final decision on the HBEP proposal, expected in December of 2016.

PROJECT BACKGROUND

HBEP is proposed as a replacement project of the existing Huntington Beach Generating Station and an amendment of the Decision to replace the existing power block technology with more efficient and current turbine technology along with the supporting equipment and infrastructure.

The approved project (12-AFC-02) was licensed as a 939 MW power plant consisting of two independently operating, three-on-one, combined-cycle gas turbine power blocks. Each power block would have consisted of three Mitsubishi natural gas-fired combustion turbine generators, three supplemental-fired heat recovery steam generators, one steam turbine generator, an air-cooled condenser, and related ancillary equipment. No new offsite linear facilities are proposed as part of this project.

As with the Licensed HBEP, the Amended HBEP facility will be air-cooled, eliminating the need for large quantities of once-through cooling seawater. The minimal potable water necessary for HBEP's construction, operational process and sanitary purposes would be provided by the city of Huntington Beach, which has provided a will-serve letter indicating there is sufficient supply of potable water to accommodate the Amended HBEP. Alternative water sources, including potential use of reclaimed water to support the HBEP, were analyzed and determined to be infeasible. During operation, storm water and process wastewater would be discharged into a retention basin and then discharged to the ocean via the existing outfall. Discharge flows would substantially decrease compared to existing conditions due to decreased plant water use, and all discharges would meet ocean discharge standards. Sanitary wastewater would be conveyed to the Orange County Sanitation District through an existing sewer connection.

PROPOSED PROJECT LOCATION AND DESCRIPTION

HBEP footprint is located within the existing operating HBGS located in Huntington Beach, California at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (Highway 1) and Newland Street. The site is privately owned land and is relatively flat with an approximate elevation of 10 to 14 feet above mean sea level. The project borders a manufactured home/recreational vehicle park on the west, a tank farm on the north, the Magnolia Marsh wetlands on the north and east, and the Pacific Ocean and Huntington Beach State Park on the south and southwest.

PROJECT OBJECTIVES

The amended AFC describes the applicant's objectives for the HBEP proposal, which are summarized as follows:

- Provide efficient, reliable and predictable power supply by using combined-cycle, natural gas-fired combustion turbines to replace the once-through-cooling (OTC) generation;
- With the closure of San Onofre Nuclear Generating Station, proposed facility provides replacement generation for southern California customers;
- Eliminate use of ocean water for once-through-cooling;
- Be able to support the local capacity requirements of Southern California's Western Los Angeles Basin;
- Develop a 844 MW power generation plant that provides efficient operational flexibility with rapid-start and fast ramping capability to allow for efficient integration of renewable energy sources in the California electrical grid;
- Reuse existing electrical, water, wastewater, and natural gas infrastructures and land to minimize land resource and environmental justice impacts by developing on an existing brown field site;
- Site the project to serve the load area without constructing new transmission facilities; and
- Site the project on property that has industrial land use designation with consistent zoning.

PROJECT ALTERNATIVES

Project alternatives developed for the amended HBEP are fully discussed in the **ALTERNATIVES** section of this PSA, and include an evaluation of the following:

1. No Project Alternative: For the purposes of this analysis, the no project alternative is considered to be the construction and operation of the previously licensed HBEP in the 2014 Commission Decision.

2. Alternative Site Configurations: The 2014 Decision evaluated the potential to reconfigure the project elements on the HBGS site to avoid or lessen noise, visual, and coastal impacts. The Decision concluded reconfiguring the site layout would not significantly lessen or avoid any operational noise impacts. Regarding visual impacts, the Decision concluded moving the visually prominent structures within the HBGS site would not reduce their visibility from sensitive viewpoints to any great extent and would not significantly lessen or avoid visual impacts. Related to coastal resources, the Decision concluded impacts identified in a report by the California Coastal Commission on the licensed HBEP primarily relating to Land Use, Noise and Vibration, and Visual Resources, would not be significantly lessened or avoided by reconfiguration of the project site

3. Alternative Sites Evaluation: The 2014 Decision concluded the location of the licensed HBEP cannot vary substantially from the HBGS site and established a firm connection between the licensed HBEP project and the existing HBGS. The 2014 Decision concluded any alternative site would require conversion of some other area of similar acreage to a new electrical power generation facility.

4. Alternative Generation Technology: The 2014 Decision evaluated primarily whether alternative generation technologies would reduce air quality impacts of the licensed HBEP. The technologies evaluated included conventional boiler and steam turbine, simple-cycle combustion turbine, alternate equipment, renewable resources, and recycled water.

5. Clutches and Synchronous Condensers: Clutches were not proposed in this petition to amend, and therefore were not reviewed for impacts. However, recent Energy Commission project siting committees have asked whether and when clutches could be installed, and what that would mean for the project's impacts.

SUMMARY OF CONCLUSIONS

Staff reviewed alternatives previously analyzed for the licensed HBEP design and related facilities, alternative technologies, and the "no project" alternative. Alternatives previously found to be infeasible remain infeasible, and would not substantially reduce one or more significant effects of the amended HBEP. In addition, no new information shows alternatives which are considerably different from those analyzed in the previous staff assessment for the licensed HBEP that would substantially reduce one or more significant effects on the environment. Therefore, in accordance with CEQA Guidelines section 15162, staff concludes that no supplementation to the 2014 Commission Decision is necessary for Alternatives. The Committee may rely upon the environmental analysis and conclusions of the 2014 Decision with regards to Alternatives and does not need to re-analyze them.

Staff's conclusion is supported by the fact that the Decision for the licensed HBEP contains an acceptable analysis of a reasonable range of alternatives to the project and contains an adequate review of alternative project sites, alternative site configurations, alternative generation technology, and the "no project" alternative.

SUMMARY OF ENVIRONMENTAL CONSEQUENCES AND MITIGATION

Below is a summary of environmental consequences and mitigation proposed in this PSA. This section also provides a summary of outstanding information that will be analyzed in the FSA.

Executive Summary Table 1-2
Environmental and Engineering Assessment

Technical Area	Complies with LORS	Impacts Mitigated	Additional Information Required
Air Quality/Greenhouse gases	Yes	Yes	No
Biological Resources	Yes	Yes	No
Cultural Resources	Yes	Yes	No
Hazardous Materials	Yes	Yes	No
Land Use	Yes	Yes	No
Noise and Vibration	Yes	Yes	No
Public Health	Yes	Yes	No
Socioeconomics	Yes	Yes	No
Soil and Water Resources	Yes	Yes	No
Traffic & Transportation	Yes	Yes	No
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	Yes	Yes	No
Power Plant Reliability	N/A	N/A	No
Transmission System Engineering	Yes	Yes	No

AIR QUALITY/GREENHOUSE GASES:

Staff concludes that with the adoption of the attached conditions of certification, the Amended HBEP would not result in significant air quality related impacts during project operation, and that the Amended HBEP would comply with all applicable federal, state and South Coast Air Quality Management District (SCAQMD or District) air quality LORS.

The proposed modifications include changing the turbine technology in one combined-cycle power block from Mitsubishi Heavy Industries 501DA three-on-one turbines to GE 7FA.05 two-on-one turbines with a nominal capacity of 644-MW net with an auxiliary boiler. The other power block would be changed to two GE LMS-100PB simple-cycle turbines with a nominal combined capacity of 200 MW. In accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that supplementation to the 2014 Decision is necessary for Air Quality. These proposed project changes constitute a considerable change in fact and circumstance from the 2014 Decision requiring a complete re-analysis of the project and air quality impacts.

Staff concludes that operating period mitigation would be provided in the form of Regional Clean Air Incentives Market (RECLAIM) Trading Credits (RTCs) and emission reduction credits (ERCs) as required by District rules and that these measures would fully mitigate emissions of all nonattainment pollutants and their precursors at a minimum ratio of one-to-one. These mitigation measures reduce potential operational impacts of the proposed project to less than significant.

Staff includes the approved Conditions of Certification **AQ-SC1** through **AQ-SC5** to mitigate construction impacts. Compliance with these conditions is expected to greatly reduce or eliminate the potential for significant adverse air quality impacts during construction of the Amended HBEP. PM10 and PM2.5 impacts during the approximately 10-year project construction period would cause exceedances of health-based ambient air quality standards and thus these impacts would be significant unless mitigated. Staff recommends **AQ-SC6** to mitigate these potential impacts. The duration and complexity of construction that contributes to these potential impacts are due in part to the desire of the project owner and the California Independent System Operator to have continuity of generation and/or reactive power from the site. There would be concurrent construction/demolition, commissioning and operation activities throughout the construction period. For the licensed HBEP, Energy Commission approved Condition of Certification **AQ-SC6** to further mitigate the PM emissions by using a local street sweeping program during the construction period (CEC 2014bb). For the Amended HBEP, staff proposes to revise Condition of Certification **AQ-SC6** according to the revised construction emissions, which would be less than those for the licensed HBEP.

Global climate change and greenhouse gas emissions from the Amended HBEP are discussed and analyzed in **AIR QUALITY APPENDIX AIR-1**. The Amended HBEP would emit approximately 0.381 metric tonnes of carbon dioxide per megawatt hour ($MTCO_2$/MWh), which would comply with Greenhouse Gases Emission Performance Standard of 0.5 $MTCO_2$/MWh (Title 20, California Code of Regulations, section 2900 et seq.). The Amended HBEP would be subject to federal mandatory reporting of GHG emissions. The facility owner may have to provide additional reports and GHG reductions, depending on the future regulations formulated by the U.S. EPA or the ARB.

The proposed GE 7FA.05 combined-cycle turbines are 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 CO_2/MWh, gross) or (1,030 lb CO_2/ MWh, net) for new base load natural gas fueled turbines. The proposed GE LMS-100PB simple-cycle turbines are expected to comply with the limit of 120 lb CO_2 per million Btus (MMBtu) of natural gas heat input for new non-base load natural gas fueled turbines. Should the combined-cycle turbines operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. No specific GHG conditions of certification are proposed in the **APPENDIX AIR-1**, but **AQ-14** and **AQ-58** would ensure compliance with the new federal standards.

BIOLOGICAL RESOURCES

The proposed modifications in the amended HBEP would not result in new significant impacts on biological resources, substantial increases in the severity of previously identified significant impacts, or necessitate any material changes to the biological resource conditions of certification identified in the Decision for the approved HBEP (CEC 2014bb) to mitigate impacts or maintain compliance with applicable LORS related to biological resources. Therefore, in accordance with CEQA Guidelines section 15162, staff concludes that no supplementation to the Decision is necessary for biological resources.

Consistent with the Decision for the approved HBEP, with implementation of the previously approved conditions of certification (with minor, immaterial changes), the amended HBEP would not result in significant direct, indirect, or cumulative impacts to biological resources and would conform to all applicable LORS related to biological resources.

CULTURAL RESOURCES

Staff concludes that proposed amendment would not result in new significant environmental effects, or increase the severity of previously identified significant effects. No known, significant cultural resources (that is, historical resources, unique archaeological resources, or tribal cultural resources) have been identified in the amended HBEP project area of analysis. Similar to the licensed HBEP, construction of the project as amended could result in impacts on buried, as-yet-unidentified cultural resources. However, the amended project components appear consistent with the scale of excavation described for the licensed project. Staff therefore concludes that existing conditions of certification (Conditions) **CUL-1–8** for the HBEP are sufficient to reduce the severity of any inadvertent impacts on buried cultural resources to less than significant. Thus, in accordance with CEQA Guidelines section 15162, staff concludes that no supplementation to the Decision for the HBEP is necessary for Cultural Resources. Staff also finds that the amended project would conform to applicable LORS relevant to cultural resources.

EFFICIENCY

Similar to the conclusions in the 2014 Decision for the HBEP, the amended HBEP project would create no significant impacts related to power plant efficiency. Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Decision is necessary for Power Plant Efficiency. The Committee may rely upon the analysis and conclusions of the Decision with regards to Power Plant Efficiency and does not need to re-analyze them.

The thermal efficiency of the combined-cycle portion of the amended HBEP would compare quite favorably with the efficiency of the licensed combined-cycle HBEP. Furthermore, the efficiency of the simple-cycle units for the amended HBEP would be comparable to the efficiency of other modern simple-cycle units. The needed quantities of natural gas fuel for the amended project would not result in a significant impact on natural gas supplies and resources

FACILITY DESIGN

Similar to the conclusions in the Decision for the HBEP, the amended HBEP project would create no significant impacts related to facility design. Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Decision is necessary for Facility Design. The Committee may rely upon the analysis and conclusions of the Decision with regards to Facility Design and does not need to re-analyze them.

Staff concludes that the amended project would comply with applicable engineering LORS. The same Facility Design conditions of certification contained in the Decision, and presented below, would ensure compliance with these LORS.

GEOLOGY & PALEONTOLOGY

The PTA for the HBEP does not seek to substantially modify the existing Geology and Paleontology conditions of certification, but staff proposes an additional condition of certification to mitigate potential impacts to public health and safety from tsunami inundation. Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that supplementation to the 2014 HBEP Commission Decision is necessary for Geology and Paleontology. The Committee should re-analyze the conclusions of the 2014 Decision alongside this new information. This section augments the existing record to reflect current environmental conditions and policy considerations.

HAZARDOUS MATERIALS

The PTA for the HBEP proposes to modify the project and would not require substantive changes to the existing set of hazardous materials management conditions of certification. Consistent with the conclusions in the project's 2014 Decision, staff has determined that the potential impacts of the proposed PTA would be less than significant. Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2014 Decision is necessary for Hazardous Materials Management. The committee may rely upon the environmental analysis and conclusions of the 2014 Decision with regards to Hazardous Materials Management and does not need to re-analyze them.

Staff determined that by following the existing conditions of certification resulting from the 2014 Decision with minor edits to conditions **HAZ-4**, **HAZ-8**, and **HAZ-9**, hazardous materials storage and use at HBEP would comply with all applicable LORS and would not result in any unmitigated significant potential impacts to the public or environment.

LAND USE

Energy Commission staff concludes that the proposed amendment to the license for the HBEP would have no new land use impacts and the mitigation for the original project would still be applicable. This mitigation would not require any substantive changes beyond the minor update to condition of certification **LAND-1** to include the additional 1.4 acres that the project owner has acquired from SCE, increasing the size of the HBEP site from 28.6 acres as licensed to 30 acres as amended. Staff also concludes that the findings of fact from the 2014 Decision would still apply to the amended HBEP. Therefore, in accordance with CEQA Guidelines section 15162, staff concludes that no supplementation to the Decision is necessary for Land Use. The Committee may rely upon the environmental analysis and conclusions of the Decision with regards to land use and does not need to re-analyze them.

NOISE AND VIBRATION

Similar to the conclusions in the 2014 Decision (CEC 2014bb), the potential impacts from the changes to the HBEP (HBEP 2015a) as proposed in the PTA would be less than significant. Therefore, in accordance with the California Environmental Quality Act Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Decision is necessary for Noise and Vibration. The Committee may rely upon the environmental analysis and conclusions of the Decision with regards to Noise and Vibration and does not need to re-analyze them.

Conditions of certification **NOISE-1** through **NOISE-8** contained in the Decision would be sufficient to reduce impacts from the amended project to a less than significant level and to ensure the project would remain in compliance with applicable LORS relating to noise and vibration.

PUBLIC HEALTH

California Energy Commission staff has analyzed the potential human health risks associated with construction, demolition and operation of the HBEP (12-AFC-02). Given the scope of the changes proposed in the PTA, staff's analysis of potential health impacts of the HBEP was done as if HBEP was a new project, and based on a conservative health protective methodology that accounts for impacts to the most sensitive individuals in a given population. Staff concludes that there would be no significant health impacts from the HBEP's potential toxic air contaminant emissions. Staff also concludes that the proposed modification would not affect the HBEP's ability to comply with applicable health LORS.

Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation is necessary and the Committee can rely on the analysis and conclusions of the Decision with regards to Public Health and does not need to reanalyze them.

RELIABILITY

Similar to the conclusions in the 2014 Decision for the HBEP, the amended HBEP 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 other electric generation power plants, including the licensed HBEP. Also similar to the licensed project, 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 Decision is necessary for Power Plant Reliability. The Committee may rely upon the analysis and conclusions of the Decision with regards to Power Plant Reliability and does not need to re-analyze them.

SOCIOECONOMICS

Energy Commission staff concludes that the proposed amendment to the licensed HBEP would not cause significant direct, indirect, or cumulative adverse socioeconomic impacts on the project area's housing, schools, law enforcement services, and parks. Staff also concludes that the amended HBEP would not induce a substantial population growth or displacement of population, or induce substantial increases in demand for housing, parks, or law enforcement services. Conditions of certification **SOCIO-1** and **SOCIO-2** from the 2014 Decision would ensure project compliance with state and local LORS.

Staff also concludes that the findings of fact and the conclusions of law from the Decision would still apply to the amended HBEP. Therefore, in accordance with CEQA Guidelines Section 15162, staff concludes that no supplementation to the Decision is necessary for Socioeconomics. The Committee may rely upon the environmental analysis and conclusions of the Decision for Socioeconomics and does not need to re-analyze them.

SOIL AND WATER RESOURCES

The changes sought in the PTA to the HBEP would not result in any substantial modifications to the existing Soil & Water Resources conditions of certification. There are no new significant environmental effects or any substantial increase in the severity of previously identified significant adverse effects that would require major revisions of the 2014 Decision. Nor is there new information of substantial importance that could not have been known in the Decision regarding substantially more severe impacts. Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Decision is necessary for Soil & Water Resources. The Committee may rely on the conclusions of the Decision in analyzing the changes to the project's design, operation, and performance pursuant to Title 20, section 1769. This section augments the existing record to reflect current environmental conditions and policy considerations.

Staff and petitioner suggest a minor revision to the conditions of certification. **Soil & Water Table 1** summarizes the proposed change.

TRAFFIC & TRANSPORTATION

Staff reviewed potential traffic and transportation impacts previously analyzed for the licensed HBEP. Staff concludes that the amended HBEP would not result in new significant traffic and transportation effects or increase the severity of previously identified significant effects. In accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2014 Commission Decision is necessary for traffic and transportation. The Committee may rely upon the environmental analysis and conclusions of the 2014 Decision with regards to traffic and transportation and does not need to re-analyze them.

The amended HBEP would remain in compliance with applicable LORS related to traffic and transportation. Although the proposed amended HBEP would require additional roadway improvements compared to the licensed HBEP, existing condition of certification **TRANS-4** would ensure the project owner complies with the city of Huntington Beach's requirements for encroachments into public rights-of-way.

TRANSMISSION LINE SAFETY/NUISANCE

The PTA for the licensed HBEP proposes project modifications that would not change the Transmission Line Safety and Nuisance (TLSN) conditions of certification as already approved. These certification requirements were intended in the 2014 Decision to ensure that any transmission line safety and nuisance impacts would be less than significant. Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2014 Decision is necessary for TLSN. The Committee may rely upon the environmental analysis and conclusions of the 2014 Decision regarding TLSN and does not need to re-analyze them. Staff's assessment shows that the proposed design and operational plan would not affect the ability of the Amended HBEP to comply with LORS given that the previously-approved conditions of certification would be retained.

TRANSMISSION SYSTEM ENGINEERING

The proposed transmission facilities between the new generators at the HBEP and SCE Huntington Beach Switching Station including the step-up transformers, the 230 kV overhead transmission lines, and terminations, are acceptable and would comply with all applicable LORS. The HBEP interconnection with the transmission grid would not require additional downstream transmission facilities (other than those proposed by the applicant) that require CEQA review.

The HBEP generation output is less than the generation output of the project as approved in the 2014 Decision. The HBEP would not cause additional downstream transmission impacts other than those identified in the Queue QC5 Phase II Interconnection Study Report Dated December 3, 2013, from California Independent System Operator. The Study Report is still valid and no new study would be required.

Staff proposes no changes to Conditions of Certification TSE 1-5. The HBEP, as amended, would comply with LORS.

VISUAL RESOURCES

Staff reviewed potential visual resources impacts previously analyzed for the HBEP. Because the amended HBEP would change the types, sizes, and massing of power plant structures on the site, staff evaluated how those changes could affect views of the project site for the key observation points closest to the project site. Staff concludes that the amended HBEP would not result in new significant adverse impacts on visual resources or increase the severity of previously identified significant effects. The amended HBEP would not cause any inconsistencies with visual resources LORS identified in the 2014 Decision) (Energy Commission 2014a). The amended HBEP does not change the “Findings of Fact” or “Conclusions of Law” for visual resources that are contained in the Decision.

Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2014 Decision is necessary for Visual Resources. The Committee may rely upon the environmental analysis and conclusions of the Commission Decision with regards to Waste Management and does not need to re-analyze them.

WASTE MANAGEMENT

The PTA for the HBEP proposes to modify the project, resulting in changes to an existing Waste Management condition of certification **WASTE-5**. Similar to the conclusions in the 2014 Decision, the potential impacts of the proposed PTA would be less than significant if mitigated in accordance with the adopted conditions of certification. Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2014 Decision is necessary for Waste Management. The Committee may rely upon the environmental analysis and conclusions of the Commission Decision with regards to Waste Management and does not need to re-analyze them.

The City of Huntington Beach would be responsible for waste conservation programs within the city's limits. Therefore **WASTE-5** would be modified to have the project owner provide a Construction and Demolition Debris Waste Reduction and Recycling Plan to the CPM and the city of Huntington Beach.

As with the HBEP Decision, the amount of waste generated by the HBEP would not significantly impact nonhazardous or hazardous landfill capacity. As with the licensed HBEP, the amended HBEP would be consistent with the applicable waste management LORS if staff's approved conditions of certification, with the previously described modification, are implemented.

WORKER SAFETY AND FIRE PROTECTION

The PTA for the HBEP proposes to modify the project which will not necessitate modification to the existing set of Worker Safety and Fire Protection conditions of certification. Similar to the conclusions in the 2014 Decision, the potential impacts of the proposed PTA would be less than significant. Therefore, in accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Decision is necessary for Worker Safety and Fire Protection. The committee may rely upon the environmental analysis and conclusions of the Decision with regards to Worker Safety and Fire Protection and does not need to re-analyze them.

Staff determined that the LORS applicable to the project remain the same since the Decision. Staff further proposes a new condition of certification **WORKER SAFETY-7** that would clarify that conformance to the recommended practices of fire protection standard National Fire Protection Association 850 is required.

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" (Cal. Code Regs., tit. 14, § 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" (Cal. Code Regs., tit. 14, § 15130(a)(2)). 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" (Cal. Code Regs., tit. 14, § 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" (Cal. Code Regs., tit. 14, § 15130(b)).

DEFINITION OF THE CUMULATIVE PROJECT SCENARIO

Cumulative impacts analysis is intended to identify past, present, and probable future projects 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 on the Master Cumulative Project List below are required to undergo their own independent environmental reviews under CEQA. Staff developed the list by contacting planning staff with the city of Huntington Beach, Costa Mesa, New Port Beach, Fountain Valley, Seal beach, Cypress, Long Beach and surrounding jurisdictions in Orange County conducting a review of project information from other agencies, including the California Department of Transportation, and the CEQANet database to develop a list of past, present, and reasonably foreseeable projects.

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." (Cal. Code Regs., tit. 14, § 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." (Cal. Code Regs., tit. 14, § 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. All projects used in the cumulative impacts analyses for this PSA are listed in the cumulative projects table (**Executive Summary Table 2**), and locations are shown on **Executive Summary Figure 1**.

APPROACH TO CUMULATIVE IMPACT ANALYSIS

This PSA evaluates cumulative impacts within the analysis of each resource area, following three steps:

- Define the geographic scope of cumulative impact analysis for each discipline, based on the potential area within which impacts of the HBEP amendment could combine with those of other projects.
- Evaluate the effects of the HBEP amendment in combination with past and present (existing) projects within the area of geographic effect defined for each discipline.
- Evaluate the effects of the HBEP amendment with foreseeable future projects that occur within the area of geographic effect defined for each discipline.

Executive Summary - Table 2
HBEP Amended Cumulative Project List

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
1	Huntington Beach Generating Station Demolition (Demolition of Units 3 & 4)	Demo/removal of Units 3 & 4 from the existing Huntington Beach Generating Station.	Huntington Beach Generating Station, Huntington Beach	0.05	Demo estimated Q2 2020 to Q4 2021 (20 mo.)
2	Poseidon Desalination Plant	A 50 million gallon per day, seawater desalination facility located on 11-acre portion of the existing Huntington Beach Generating Station (HBGS) facility. Project would use existing HBGS seawater intake and outfall pipelines for operations.	21730 Newland St, Huntington Beach	0.22	Planning
3	Magnolia Oil Storage Tank and Transfer Facility Demolition and Removal	Demolition and removal of three empty above ground crude oil storage tanks and ancillary site improvements.	21845 Magnolia St, Huntington Beach	0.35	In Progress
4	Newland St Residential (Pacific Shores)	Develop and subdivide former industrial site to residential with 204 multi-family residential units and two-acre public park.	21471 Newland St, Huntington Beach	0.40	Completed

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
5	Remedial Action Plan for Ascon Landfill Site	Remedial Action Plan (RAP) includes partial removal of waste materials and construction of protective cap over remaining waste materials.	Magnolia St and Hamilton Ave, Huntington Beach	0.43	Plan Check
6	Hilton Waterfront Beach Resort Expansion	Nine-story tower with 156 new guestrooms, appurtenant facilities, 261 parking spaces, a loading dock and other back-of-house facilities.	21100 Pacific Coast Hwy, Huntington Beach	1.02	Plan Check
7	Brookhurst Street Bridge Preventative Maintenance Project	Repair and rehabilitate the Brookhurst Street Bridge in the city of Huntington Beach.	Brookhurst St Bridge, Huntington Beach	1.11	Plan Check
8	P2-92 Sludge Dewatering and Odor Control	Build new sludge and odor control facilities at existing Plant 2.	Santa Ana River Channel, Huntington Beach	1.17	Construction scheduled Spring 2016
9	Pacific City	516 condominiums; 8 story-250 room hotel, spa and health club; and 191,100 sq. ft. visitor-serving commercial with retail, office, restaurant, cultural, and entertainment	21002 Pacific Coast Hwy, Huntington Beach	1.26	Under Construction
10	Pierside Pavilion Expansion	Proposes to construct a connecting four-story, mixed-use, visitor serving/office building and storefront extension.	300 Pacific Coast Hwy, Huntington Beach	1.51	Plan Check
11	The Strand	Retail, restaurants, offices, and a 149-room hotel.	155 5th St, Huntington Beach	1.63	Completed
12	Beach Walk	173 multi-family apartment units within a 4-story building, a 5-level parking structure, public and private open space areas.	19891 & 19895 Beach Blvd, Huntington Beach	2.10	Completed

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
13	LeBard Park and Residential Project	9.7-acre surplus school site for public recreation and single-family residential uses.	20461 Craimer Ln, Huntington Beach	2.16	Approved
14	Truewind- Former Wardlow School Site	49 detached single-family residential units on an 8.35-acre site.	9191 Pioneer Dr, Huntington Beach	2.16	Under Construction
15	Brookhurst Street and Adams Avenue IIP	Widening of the Brookhurst St/Adams Ave intersection in all directions.	Brookhurst St and Adams Ave, Huntington Beach	2.38	Draft Environmental Impact Report (DEIR)
16	Lighthouse Project	89-unit (49 residential units, 40 live/work units), three-story mixed-use development. 332 parking garage, 2aces of common open space.	1620-1644 Whittier Ave, Costa Mesa	2.42	Initial Study (IS)/Mitigated Negative Declaration (MND)
17	Ebb Tide Residential Project	Demolition of 73 mobile home spaces, three fixed structures and related surface improvements and the development of 81 single-family detached condominium units.	Placentia Ave and 16th St, Newport Beach	2.96	MND
18	Fairwind- Former Lamb School Site	80 detached single-family residential units on a 11.65-acre site	10251 Yorktown Ave, Huntington Beach	2.96	Under Construction
19	Westside Gateway Project	Seeking approval to redevelop a 9-acre project site with a mix of 177 dwelling units (residential lofts and live/work). Redevelopment includes demolition of all existing buildings and parking areas.	671 W. 17th St, Costa mesa	3.20	Under Construction

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
20	Beach and Ellis - Elan Mixed Use	274 units (26 studio, 123 one-bedroom, 6 live-work, 119 two-bedroom units of which 27 are affordable units) also includes: 8,500 sq. ft. commercial, 17,540 sq. ft. public open space and 31,006 sq. ft. residential private open space.	18502, 18508-18552 Beach Blvd, Huntington Beach	3.37	Under Construction
21	Newport Beach City Hall Reuse Project- Now called the "Lido House Hotel"	Four story, 130-room hotel set on a 4.25-acre site that formerly housed the Newport Beach City Hall.	3300 Newport Blvd, Newport Beach	3.45	IS/ND
22	2277 Harbor Boulevard Project	Proposal involves demolishing existing 236-room motel and the construction of a four-story, 224-unit luxury apartment project.	2277 Harbor Boulevard, Costa Mesa	3.50	IS/MND
23	Mesa Verde East Project	Demolition of existing site improvements and construction of a 10-unit, 2-story, detached residential development.	Adams Avenue & Mesa Verde Dr. East, Costa Mesa	3.69	Notice of intent to adopt negative declaration
24	Oceana Apartments	Four story apartment building with 78 affordable housing units for income levels at 30 to 60 percent of Orange County median income on 2-acre site.	18151 Beach Blvd, Huntington Beach	3.75	Under Construction
25	Bolsa Chica Roadway Embankment Reconstruction Project	Install pedestrian safety cable rails and metal beam guardrails along State Route 1 in Huntington Beach.	SR 1 (Pacific Coast Hwy) from Warner Ave to Seapoint Ave, Huntington Beach	3.95	IS/ND
26	Huntington Beach Senior Center	One-story senior center on an undeveloped portion of Central Park. Approximately 227 parking spaces will be provided for visitors and City vehicles.	Central Park (5-acre area; SW of the intersection of Goldenwest St and Talbert Ave)	4.14	Under Construction

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
27	Hyundai Motor America Corporate Campus Project	Expand existing corporate headquarters with a 469,000-sq. ft. campus	10550 Talbert Ave, Fountain Valley	4.39	Completed
28	Vision 2020 Facilities Master Plan	1,238,542 sq. ft. of academic, administrative, residential, and parking facilities on Orange Coast College campus.	2701 Fairview Rd, Costa Mesa	4.41	Unknown
29	Well #6 Colored WTP	Construct WTP within the next two years.	Harbor Blvd at Gisler Ave,Costa Mesa	4.48	Unknown
30	Fountain Valley Civic Center Specific Plan	Build Ayres Hotel, 88 residential units (27 single-family, 61 townhomes), and 2,300 sq. ft. of retail space on 8.62-acres.	Brookhurst St and Slater Ave, Fountain Valley	4.64	Unknown
31	Costa Mesa High School Sports Complex	Construct sports complex with 997-seat bleachers, replacing existing track and field with synthetic field and rubber track, and provide various associated facilities.	2650 Fairview Rd, Costa Mesa	4.68	Unknown
32	Back Bay Landing Project	New reservoir foundation, install underground pipelines	East Coast Hwy at Bayside Dr, Newport Beach	4.76	Under review with Coastal Commission
34	Warner-Nichols Project	Demolish six buildings	Warner Ave at Nichols Ln, Huntington Beach	4.92	Adopted
35	Beach Blvd and Warner Ave Intersection Improvement Project	Construct westbound right turn lane on Warner Ave at intersection and associated improvements including new 5 ft. wide, 15 ft. long sidewalk along west side of A Lane.	Intersection of Beach Blvd and Warner Ave, on the north side of Warner Ave from Beach Blvd to the alley between A Lane and B Lane, including portions of the adjacent commercial properties to the north at 16990 Beach Blvd, 8021 Warner Ave, and 8071 Warner Ave.	4.92	Adopted

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
36	Beach Edinger Corridors Specific Plan	Removal Action Workplan includes excavation of Volatile Organic Compound (VOC) and lead-impacted soil areas within and around site building. Approximately 1,800 tons of soil to be generated from excavation of 3,000 sq. ft. area to 12 ft. below the ground surface. Excavation then proceeds approximately 4 ft. below water table. Groundwater to be pumped up to 24 hrs. to remove estimated 10,000 gallons of groundwater. Soil transported off-site to permitted facility. Soil confirmation sampling of excavation flood and sidewalls to verify soil exceeding cleanup objectives been satisfactory removed. Following completion of the remedial excavation and confirmation sampling, excavation backfilled with either native material taken from other areas of the property or from an approved borrow site. Excavated area returned to grade and suitable standards of completion. Installation of sub-slab methane-mitigation barrier and venting system to address naturally occurring methane in site area. Sub-slab system will be installed beneath the new multi-family residential building that will occupy the site and surrounding properties.	Edinger Ave to Atlanta Ave, Huntington Beach	5.16	Planning
37	Upper Newport Bay-East Bluff Drainage Repair Project	Drainage improvements and erosion repair within bluff on E side of Upper Newport Bay.	E of Back Bay Dr and W of Vista Del Oro, Newport Beach	5.37	Proposed

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
38	Yakult USA Manufacturing Facility	77,000 sq. ft. manufacturing facility on 8.8-acres.	17256 Newhope St, Fountain Valley	5.48	Completed
39	Parkside Estates	111 single-family residences; 23-acres preserved, restored and enhanced open space; 1.6-acre neighborhood park; public trails; and water quality treatment system.	W side Graham St, S of Warner Ave, along E Garden Grove Wintersburg Flood Channel 17221 (S of Greenleaf Ln), Huntington Beach	5.67	Planning
40	Ganahl Hardware Store and Lumber Yard	65,263 sq. ft. building materials store with administrative offices and 286 parking spaces.	Bristol St and Northbound Newport Blvd, Huntington Beach	5.74	Completed
41	Brightwater	347 single-family units and over 37-acres habitat restoration and trails.	Warner Ave and Los Patos Ave, Huntington Beach	5.77	Under Construction
42	Newport Executive Court Project	Project includes construction of two, 2-story medical office buildings and a 324-space surface parking lot on 4-acres.	Cross Streets: Birch St and Mesa Dr, Newport Beach	5.88	Plan Check
43	General Plan Update EIR (North Newport Center)	Increase the multi-family residential development allocation from 430 units to 524 units on 121-acres.	Newport Beach	5.89	Unknown
44	Monogram Apartments (Formerly Pedigo)	Four-story apartment building with 510 dwelling units and six-level, 862-space parking structure.	7262,7266,7280 Edinger Ave and 16001, 17091 Gothard St, Huntington Beach	5.96	Plan Check
45	The Boardwalk (Murdy Commons)	487 dwelling units and 14,500 sq. ft. of commercial area on a 12.5-acre site with 1/2 acre public park.	7441 Edinger Ave-Northeast corner of Edinger Ave and Gothard St (Former Levitz Furniture store site)	5.97	Under Construction. First two phases have opened for occupancy.
46	Edinger Walmart	100,865 sq. ft. vacant retail building within an existing commercial center.	SW corner of Goldenwest St and Edinger Ave, Huntington Beach	6.02	Completed

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
47	Airport Circle Residential Project	45-unit condominium subdivision with open space on 2.5-acre site. Site layout: 8 detached three-story buildings with 4 to 8 attached dwelling units.	16911 Airport Cir. Huntington Beach	6.04	Plan Check
48	The Village at Bella Terra	Costco Wholesale, with gasoline service station and mixed-use retail and residential project.467 multi-family residential units within four-story building.	7777 Edinger Ave, Huntington Beach	6.06	Completed
49	San Diego Freeway I-405 Improvement Project	One general-purpose lane in each direction on I-405 from Euclid St to the I-605 interchange, add tolled express lane in each direction of I-405 from SR-73 to SR-22 East.	I-405 between SR-73 & I-605, Costa Mesa, Seal Beach	6.06	Unknown
50	Huntington Beach Lofts	Five-story, 385-luxury residential units located above 10,000 sq. ft. of street level retail and commercial uses.	7302-7400 Center Ave, Huntington Beach	6.16	Under Construction
51	Vans Skate Park	Construction of a skate park.	7471 Center Ave, Huntington Beach	6.35	Completed
52	Wyndham Boutique Hotel/High-Rise Residential Project	Demolition of Wyndham Hotel parking garage and construction of a 100-unit condominium tower adjacent to a new 6.5-level parking garage with 1 subterranean level and 5.5 levels above ground.	3350 Ave of the Arts, Costa Mesa	6.53	Approved
53	Harmony Cove Marina Development	23-boat slip marina, eating and drinking establishment with outdoor dining area and alcoholic beverage sales, and ancillary uses to marina.	N side of Warner Ave, W of Weatherly Ln-Formerly Percy Dock	6.55	Proposed

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
54	OC-44 Pipeline Rehabilitation Project	Sip-line existing 42-inch pipeline with new 30-inch Ductile Iron Pipe (DIP). To accommodate these improvements, a pipe jacking operation would be conducted, requiring three access pits.	University Dr and La Vida, Newport Beach	6.61	Approved- Construction 2018-2020
55	Civic Center and Park Project	Construction of park, city hall building, and 450 parking spaces.	Avocado Ave and McArthur Blvd, Newport Beach	6.62	Unknown
56	Uptown Newport Village Specific Plan Project	Mixed-use project with 1,244 residential units, 11,500 sq. ft. retail, and a 2-acre park.	Jamboree Rd and Fairchild Rd, Newport Beach	6.92	Approved
57	Tennis Estates Tree Trimming and Management Plan	Tree Trimming and Management Plan for the Tennis Estates Homeowners Association property in the Coastal Zone.	16380 Wimbledon Ln, Huntington Beach	7.05	In Progress
58	Rofael Marina and Caretaker Facility	Construct marina on 6,179 sq. ft. property.	16926 Park Ave, Huntington Beach	7.12	In Progress. Requires Coastal Development Permit and a Conditional Use Permit.
59	Campus and Jamboree	1,600 residential units (5 to 6-story apartments), 17,000 sq. ft. plus primary retail in Irvine Technology Center, and up to 23,000 sq. ft. accessory retail and/or residential-serving amenities, 1-acre public park, and two 0.5-acre public plazas.	NW corner of Campus and Jamboree, Irvine	7.37	Phase 1 Under Construction (9/26/2015)
60	Mater Dei High School Parking Structure	Three-level parking structure	1202 W Edinger Ave, Santa Ana	7.80	Proposed, 3-5 years 2018 at earliest

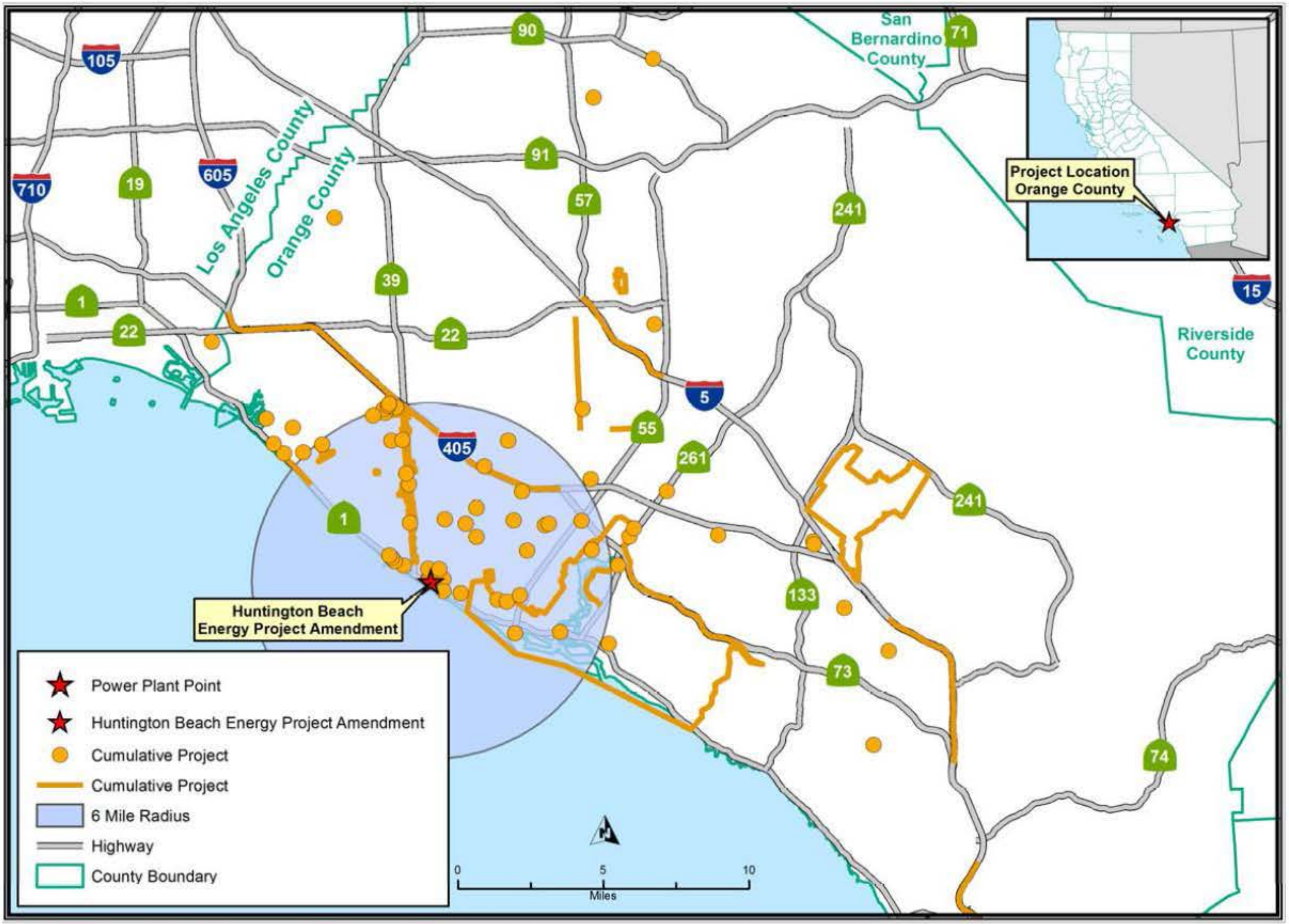
Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
61	Sunset/Huntington Harbour Maintenance Dredging and Waterline Installation Project	Maintenance dredging and waterline Installation.	Edinger Ave and Sunset Way, Huntington Beach	7.80	Unknown
62	Warner Avenue Widening	Widening to six lanes.	Warner Ave, Santa Ana	8.48	Approved. Construction in four phases. Phase 1 Jan. 2016 to Jan 2017.
63	2801 Kelvin	384-unit apartments.	2801 Kelvin Ave, Irvine	8.70	Under Construction. 18-month construction period
64	Bristol St. Widening	Widening to six lanes.	3.9-mile stretch of Bristol St from Memory Ln to Warner Ave, Santa Ana	8.79	Under Construction. Phase 1 complete out of four phases, Phase 2 out to bid with 11-month construction period. Phase 3 June 2015 to June 2016. Phase 4 currently unfunded.
65	Vista Verde	Build 55-unit project, which is proposing to add 3 additional units to the project	5144 Michelson Dr, Irvine	10.00	Unknown
66	Grand Avenue Widening	Widening to six lanes	Grand Ave, Santa Ana	10.15	Under Construction July 2015 to March 2016.
67	I-5 Central County Improvement Project	Add second carpool lane in each direction on I-5 between the SR-55 and the SR-57.	I-5 between SR-55 and SR-57, cities of Santa Ana, Tustin and Orange.	10.39	Approved. Construction Jan. 2016 to Jan 2017.

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
68	I-5, SR-73 to El Toro Road	Widen I-5 to accommodate general-purpose lanes in each direction. Reestablish existing auxiliary lanes. Extend second carpool lane from El Toro Rd. to Alicia Parkway in both directions and modify ramps as needed. Reconstruct Avery Parkway and La Paz Rd. interchanges. 2018 to 2022	I-5 between SR-73 to El Toro Rd, cities of Laguna Hills, Laguna Woods, Laguna Niguel, Mission Viejo, Lake Forest, and San Juan Capistrano.	10.67	Proposed
69	Alamitos Energy Center	Two natural gas turbine power blocks. Power Block 1:natural-gas-fired combustion turbine generators in combined-cycle configuration, two unfired heat recovery steam generators, one steam turbine generator, air-cooled condenser, auxiliary boiler, related ancillary equipment.. Power Block 2: four simple-cycle combustion turbine generators with fin-fan coolers and ancillary facilities. 21-acre site within larger 71.1-acre Alamitos Generation Station site.	690 N Studebaker Rd, Long Beach	10.74	Proposed
70	Sexlinger Farmhouse & Orchard Residential Development Project	24 single-family homes on 5-acres.	E Santa Clara Ave at Tustin Ave, Santa Ana	11.38	On Hold, CEQA Lawsuit-Possible Appeal
71	Santa Fe Depot Specific Plan	Potential infill development at as many as 11 locations.	Between Walnut and Palmyra Aves, Orange	12.13	Unknown
72	Irvine Center Drive and Alton, NWC.	766-unit apartments.	Northwest corner of Irvine Center Dr and Alton Pkwy, Irvine	12.84	Under Construction. Estimated 24-month construction
73	Great Park Neighborhoods (Heritage Fields)	Residential housing, parks, and sports fields/complex.	Former El Toro Marine Air Station, Irvine	13.12	Unknown

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
74	Pacifica and Spectrum NWC	573-unit apartments	SW corner of Alton Pkwy and Spectrum, Irvine	13.19	Under Construction. 24-month construction
75	Cypress Community College AST	Construct storage tank.	9200 Valley View St, Cypress	14.25	Unknown
76	Recycled Water Distribution System Expansion	Build tertiary treatment facilities and transmission pipeline.	Ridge Route Dr & Moulton Pkwy, Laguna Hills and Laguna Woods	14.66	Approved
77	Coastal Treatment Plant Export Sludge Force Main Replacement	Replacement of 16,600 ft. of two 4-inch iron pipelines, eastern side of Aliso Creek.	Aliso Viejo, Awma Rd at Alicia Pkwy, Laguna Niguel	15.61	Unknown
78	ND-12-02 Aliso Creek Pedestrian Bridge/Service Road	Replace pedestrian bridge with new build.	Laguna Woods	15.91	Unknown
79	Radha Raman Vedic Mandir	Church renovation and additional construction of facilities.	1022 N Bradford Ave, Placentia	17.54	Unknown
80	Robert Diemer Filtration Plant Improvements	New reservoir foundation, install underground pipelines	3972 Valley View, Yorba Linda	19.62	Completed
81	I-5 between Avenida Pico to San Juan Creek Road	Add carpool lane both directions on I-5 between Avenida Pico to San Juan Creek Road. Reconstruct interchange at Avenida Pico. Widen northbound Avenida Pico on-ramp to three lanes. Provide dual left-turn lanes to both northbound and southbound Avenida Pico on-ramps. Add sound walls where needed.	I-5 between Avenida Pico and San Juan Creek Rd, San Clemente, San Juan Capistrano and Dana Point.	21.14	Under Construction 2013 to 2017.

EXECUTIVE SUMMARY - FIGURE 1

Huntington Beach Energy Project Amendment - Cumulative Projects Map



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: California Energy Commission, Open Street Map

ENVIRONMENTAL JUSTICE

The California Resources Agency recognizes that environmental justice (EJ) communities are commonly identified as those where residents are predominantly minorities or live below the poverty level; 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 EJ analysis is composed of the following:

- Identification of areas potentially affected by various emissions or impacts from a proposed project;
- Providing notice in appropriate languages (when possible) of the proposed project and opportunities for participation in public workshops to EJ communities;
- 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
- 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 EJ 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 EJ in their decision-making process if their actions have an impact on the environment, environmental laws, or policies. Such actions that require EJ 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 Application for Certification for the HBEP amendment, Energy Commission staff used 2010 U.S. Census data to identify the minority populations and the most recent U.S. Census data from the American Community Survey (ACS) to identify below-poverty level populations within the six-mile radius of the HBEP[1]. The demographic screening is based on *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.

The 2010 U.S. Census data staff used to identify minority-based environmental justice populations for **Socioeconomics Figure 1** used in the 2014 Commission Decision is still current. As identified in the Commission Decision, there is no minority environmental justice population present in the project's six-mile radius. To determine whether a poverty-based environmental justice population is present, staff used the most currently available poverty data from the ACS, presented in **Socioeconomics Table 1.**

Based on 2010-2014 ACS census data, 10.02 percent of people within the six-mile radius of the HBEP are living below the poverty level. Since this is less than the 12.80 percent of people living below the poverty level in Orange County, the population within a six-mile radius of HBEP does not constitute an environmental justice population as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*.

Staff in the 11 technical disciplines of Air Quality, Hazardous Materials Management, Land Use, Noise and Vibration, Public Health, Socioeconomics, Soil and Water Resources, Traffic and Transportation, Transmission Line Safety and Nuisance, Visual Resources, and Waste Management are required to consider the impacts of the HBEP on the EJ population.

ADDITIONAL ENVIRONMENTAL JUSTICE POPULATION CONSIDERATIONS

Final Guidance for Incorporating Environmental Justice Concerns in EPA's Compliance Analyses (US EPA 1998) encourages outreach to community-based organizations and tribal governments to identify those minority groups who utilize or are dependent upon natural and cultural resources that could be potentially affected by the proposed action. The Public Advisor's Office is responsible for outreach to local communities affected by a project. Cultural Resources staff initiates consultations with tribal governments to discern whether a proposed energy facility may impact cultural resources and related Native American practices.

[1] Demographic screening data is presented in the **SOCIOECONOMICS** section.

CONCLUSION

The Air Quality staff's recommendation of implementing the conditions of certification, air quality conditions and practices described in the analysis would reduce potential adverse impacts to insignificant levels and ensure that the project's emissions are mitigated to less than significant. With the adoption of the Conditions of certification, the amended HBEP would comply with all LORS. Implementation of these conditions would reduce air quality impacts to less than significant for any population in the project's six-mile radius.

The Hazardous Materials Management, Land Use, Noise and Vibration, Public Health, Socioeconomics, Soil and Water Resources, Traffic and Transportation, Transmission Line Safety and Nuisance, Visual Resources, and Waste Management staff conclude that the amended HBEP, either as proposed or conditioned through conditions of certification, would result in less than significant impacts related to their technical areas and therefore have a less than significant impact to any population in the project's six-mile radius.

INTRODUCTION

John Heiser, AICP

PURPOSE OF THIS REPORT

This Preliminary Staff Assessment (PSA) is the California Energy Commission staff's independent analysis of the proposed Huntington Beach Energy Project (HBEP or project) Petition to Amend (PTA). This PSA is a staff document. It is neither a Committee document, nor a draft decision. The PSA describes the following:

- the proposed project;
- the existing environment;
- staff's analysis of whether the facilities can be constructed and operated safely and reliably in accordance with applicable laws, ordinances, regulations and standards (LORS);
- the environmental consequences of the project including potential public health and safety impacts;
- the potential cumulative impacts of the project in conjunction with other existing and known planned developments;
- mitigation measures proposed by the petitioner, staff, interested agencies, local organizations, and intervenors which may lessen or eliminate potential impacts;
- staff's proposed conditions of certification (CoCs) under which the project should be constructed and operated, if it is certified; and
- project alternatives.

The analyses contained in this PSA are based upon information from the: 1) Application for Certification – Petition to Amend (AFC-PTA), 2) responses to data requests, 3) supplementary information from local, state, and federal agencies, interested organizations and individuals, 4) existing documents and publications, 5) independent research, and 6) comments at public hearings and workshop(s). The PSA presents preliminary conclusions about potential environmental impacts and conformity with LORS, as well as proposed CoCs that apply to the design, construction, operation and closure of the facility. The analyses for most technical areas include discussions of proposed CoCs. The CoCs contain staff's recommended measures to mitigate the project's environmental impacts and to ensure conformance with LORS. Each proposed CoC is followed by a proposed means of "verification" to ensure the CoCs are implemented.

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

ORGANIZATION OF THE PRELIMINARY STAFF ASSESSMENT

The PSA contains the Executive Summary, Introduction, Project Description, and Project Alternatives. The next 20 chapters contain the environmental, engineering, public health and safety and alternatives analyses of the proposed project. These chapters 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.

Included in the 20 technical area assessments are discussions of:

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

ENERGY COMMISSION SITING PROCESS

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

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

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

The staff prepares a PSA that presents for the petitioner, 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 30-day 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 CoCs 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 oversee the review 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 and to rebut the testimony of other parties, thereby creating a hearing record on which a decision on the project can be based. The hearing before the Committee also allows all parties to argue their positions on disputed matters, if any, and it provides a forum for the Committee to receive comments from the public and other governmental agencies.

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

AGENCY COORDINATION

As noted above, 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). However, the Commission staff typically seeks comments from, and works closely with, other regulatory agencies that administer LORS that are applicable to proposed projects. The agencies associated with the HBEP amendment include the U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, U.S. Army Corps of Engineers, California Coastal Commission, State Water Resources Control Board/Regional Water Quality Control Board, California Department of Fish and Wildlife, Caltrans, the California Air Resources Board, the South Coast Air Quality Management District, the city of Huntington Beach and the Huntington Beach Fire Department.

OUTREACH

The Energy Commission's outreach program is primarily facilitated by the Public Adviser's Office (PAO). This is an ongoing process that to date has involved the following efforts:

LIBRARIES

On November 5, 2015, Energy Commission staff sent the HBEP amended AFC to libraries in Huntington Beach, Santa Ana, Costa Mesa, Fountain Valley, Seal Beach, Eureka, Sacramento, Fresno, San Francisco, Los Angeles and San Diego.

INITIAL OUTREACH EFFORTS

The PAO reviewed related information available from the petitioner and others and then conducted its own, extensive outreach efforts to identify certain local officials, as well as interested entities, within a five-mile radius around the proposed site for the amended HBEP. These entities include schools; churches; community, cultural and health-care facilities; day-care and senior-care centers, as well as business, environmental, governmental, and ethnic organizations. By means of e-mail and letters, the PAO notified these entities of the Informational Hearing and Site Visit for the project, held on December 8, 2015 at the Hilton Waterfront Beach Resort located in Huntington Beach California.

The PAO also identified and similarly notified local officials with jurisdiction in the project area. Notices directed the public to the website for more information.

Energy Commission regulations require staff to notice, at a minimum, 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). This was done for the project. 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 amended PSA.

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 their mission. The order requires the U.S. Environmental Protection Agency (U.S. EPA) and all other federal agencies (as well as state agencies receiving federal funds) to develop strategies to address this issue. The agencies are required to identify and address any disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and/or low-income populations.

For all siting cases, Energy Commission staff conducts an environmental justice screening analysis in accordance with the *Final Guidance for Incorporating Environmental Justice Concerns in EPA’s NEPA (National Environmental Policy Act) 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.

California Statute, Sections 71000-71400 of the Government Code defines *environmental justice* to mean “fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.” Staff’s specific activities, with respect to environmental justice for HBEP, are discussed in the Executive Summary.

PROJECT DESCRIPTION

John Heiser, AICP

INTRODUCTION

The Preliminary Staff Assessment (PSA) for the Huntington Beach Energy Project (HBEP) Petition to Amend (PTA) contains the analyses of potential environmental effects and engineering factors associated with the development and operation of the project in 20 different technical areas. The owner and applicant, an indirect wholly subsidiary of AES Southland, LLC, now known as AES Huntington Beach Energy, LLC, proposes to modify the approved license with a total 844 megawatts (MW). Construction would commence in two phases with the first phase consisting of a natural gas-fired, combined-cycle, air-cooled, 644-MW electrical generating facility. After the first phase combined-cycle power block is operational, phase 2 would begin with adding two 100-MW simple-cycle gas turbines (SCGT). No new offsite linear facilities are proposed as part of this project. Located on 30 acres (28.6 acres approved in the Decision, plus an additional 1.4 acres of paved area AES acquired from Southern California Edison (SCE). The HBEP footprint is located within the existing operating Huntington Beach Generating Station located in Huntington Beach, California at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (Highway 1) and Newland Street.

This section includes information and figures from the owner's Petition to Amend the California Energy Commission's 2014 Decision (Decision) and supplemental information filed in support of the AFC, which are part of the project docket and can be accessed by selecting Dockets for this Proceeding at the following web address for reference: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=12-AFC-02C

PROJECT SETTING, LOCATION AND SITE DESCRIPTION

On June 27, 2012, AES Southland, LLC submitted an Application for Certification (AFC) for the HBEP. On October 29, 2014, the Energy Commission approved the AFC for HBEP with the Final Decision (Decision). On September 4, 2015, AES Southland LLC submitted a PTA the Final Decision for HBEP (12-AFC-02).

HBEP, as amended (12-AFC-02C), would replace the existing operational Huntington Beach Generating Station (HBGS), and be constructed on 30 acres (28.6 acres approved in the Decision, plus an additional 1.4 acres of paved area AES acquired from SCE. The HBEP footprint is located within the existing operating HBGS located in Huntington Beach, California at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (Highway 1) and Newland Street. The site is privately owned land and is relatively flat with an approximate elevation of 10 to 14 feet above mean sea level. The project borders a manufactured home/recreational vehicle park on the west, a tank farm on the north, the Magnolia Marsh wetlands on the north and east, and the Pacific Ocean and Huntington Beach State Park on the south and southwest.

The amended project would total 844 megawatts (MW). Construction would commence in two phases with the first phase consisting of a natural gas-fired, combined-cycle, air-cooled, 644-MW electrical generating facility. After the first phase combined-cycle power block is operational, phase 2 would begin with adding two 100-MW simple-cycle gas turbines (SCGT). No new offsite linear facilities are proposed as part of this project.

The approved project (12-AFC-02) was licensed as a 939- MW power plant consisting of two independently operating, three-on-one, combined-cycle gas turbine power blocks. Each power block would have consisted of three Mitsubishi natural gas-fired combustion turbine generators, three supplemental-fired heat recovery steam generators, one steam turbine generator, an air-cooled condenser, and related ancillary equipment.

The Amendment to the HBEP Final Decision from the Energy Commission is the result of the selection by SCE of the revised AES project in the 2013 Local Capacity Requirements Request for offers to provide 644 MW of nominal capacity, with different technology than that permitted in the HBEP Final Decision.

Based on this selection by SCE, Amended HBEP is a modification to the licensed HBEP with the following equipment:

- One combined-cycle, gas turbine (CCGT), 644-MW power block consisting of two General Electric (GE) Frame 7FA.05s;
- Proposed stack height of 150 feet for the GE Frame 7FA.05 combustion-turbine generator units;
- Two unfired heat-recovery steam generators equipped with two emission control systems to control CO, NOx and VOC emissions;
- One steam turbine generator;
- One air-cooled condenser (ACC) and one closed-loop air-cooled heat exchanger;
- One natural gas-fired auxiliary boiler to support the power block;
- Related ancillary equipment;
- In phase two, two GE simple-cycle LMS-100 PB combustion turbine generators (SCTGs) with a nominal capacity of 200 MWs; and
- Proposed stack height of 80 feet for the LMS100 units.

PROJECT DESCRIPTION

As discussed above, the petitioner is proposing to modify the HBEP 12-AFC-02 Final Decision (now 12-AFC-02C) by replacing power block 1 as licensed, with a two-on-one CCGT configuration described above with a nominal summer capacity of 644 MWs (net).

Power Block 2 as licensed would be replaced with two GE LMS-100 PB SCGT units with a nominal capacity of 200 MWs. Each power block will have a set of electric-powered natural gas compressors.

The HBEP will be constructed on 30 acres within the footprint of the existing HBGS. This area includes the licensed 28.6-acre site plus an additional 1.4 acres of paved area previously evaluated as temporary construction parking that the petitioner has acquired from SCE.

As part of the amendment, a total of 22 acres of combined construction parking and construction laydown area is proposed at the Plains All-American site. The licensed HBEP included approximately 1.9 acres of construction parking on the Plains site.

The construction of Power Block 1 will require the removal of the existing Unit 5 peaker (former gas turbine generator), two former fuel oil tanks, associated fuel oil pipelines, asbestos, several support buildings and containment berms which demolition activities are scheduled to begin during the 1st quarter of 2016 to the 2nd quarter of 2017. This demolition activity was approved by the Energy Commission in the October 2014 decision. All of the above demolition activities are addressed in the PTA for review of potential project cumulative impacts.

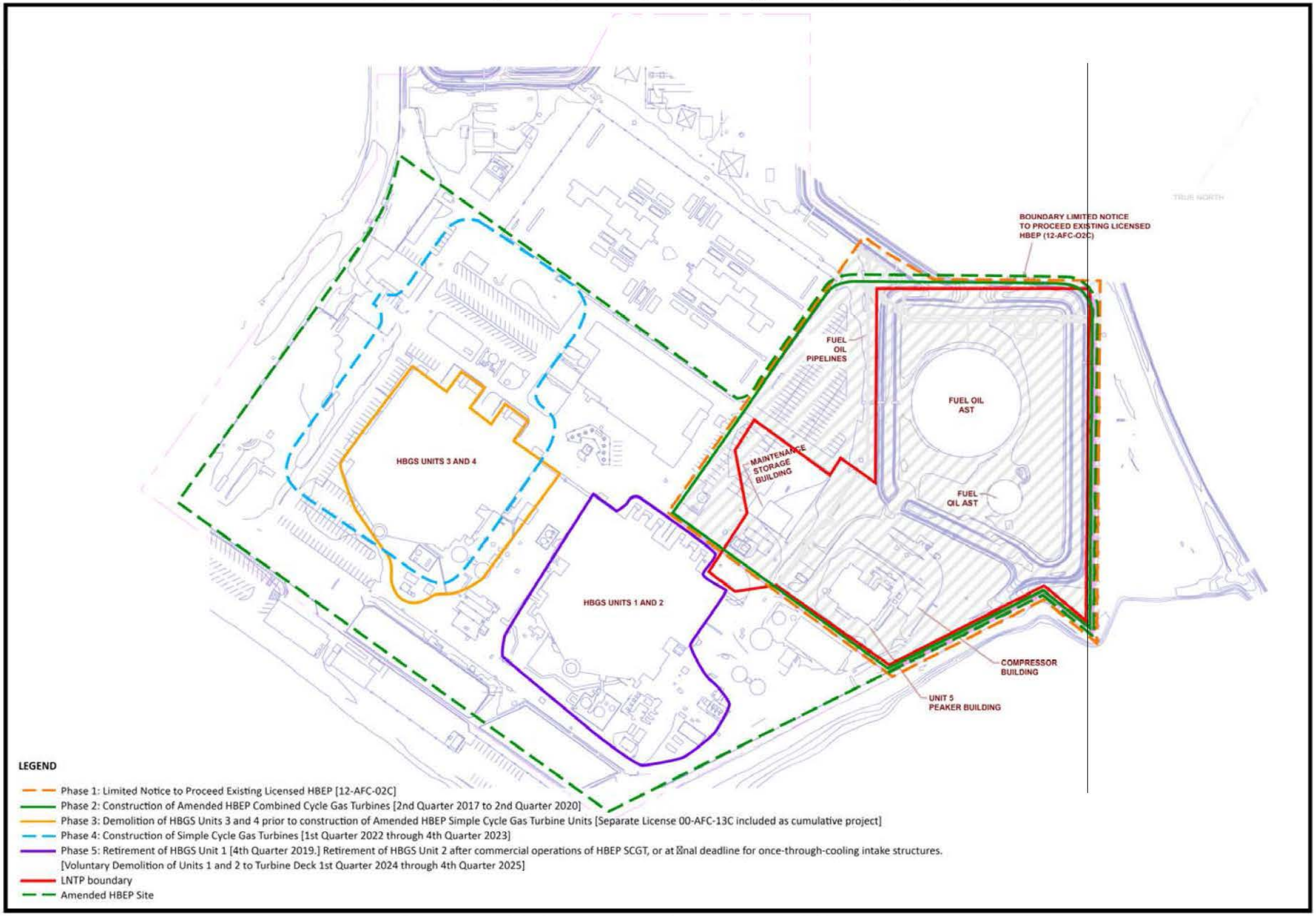
Removal/demolition of existing Huntington Beach Generating Station Units 3 and 4 will occur in advance of the construction of the Amended HBEP phase 2 SCGT power block. The demolition schedule for the removal of Units 3 and 4 are anticipated to begin during the 2nd quarter of 2020 through the 4th quarter of 2021. Existing Huntington Beach Generating Station Units 3 and 4 are licensed through the California Energy Commission (CEC; 00-AFC-13C). Demolition of these units is authorized under that license, will proceed during the amended HBEP certification process, and is not part of the amended (12-AFC-02C) HBEP project definition.

Existing Huntington Beach Generating Station Unit 1 will be retired in the fourth quarter of 2019 to provide interconnection capacity for the new CCGT units. Unit 2 will be retired either after commercial operation of the HBEP SCGT units or at the final compliance deadline for once-through-cooling intake structures as determined by the State Water Resources Control Board, after which demolition of Huntington Beach Generating Station Units 1 and 2 will commence. The Amendment indicates the demolition of Units 1 and 2 during the 1st quarter of 2024 through the 4th quarter of 2025.

The planned construction and demolition activities of the amended HBEP will occur on a schedule that allows continued operation of the existing HBGS power generation and synchronous condensers to maintain power delivery and grid reliability. The demolition work will require site preparation and grading activities. Figure 1 below Table 1 depicts the various demolition and construction phases on the HBGS site.

PROJECT DESCRIPTION - FIGURE 1

Executive Summary - Phases of Amended Huntington Beach Energy Project



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: CH2MHill

Project Description - Table 1
Demolition / Construction Activity Timeline

DEMOLITION / CONSTRUCTION ACTIVITY	TIMELINE
Demolish Unit 5 and fuel tanks	Q1 2016 - Q2 2017 16 months
Construction Power Block 1	Q2 2017 – Q2 2020 36 months
Commercial Operation Power Block 1	Q2 2020
Demolish Units 3, 4 (under separate approved License and not part of the current amended project)	Q2 2020 – Q4 2021 20 months
Construction Power Block 2	Q1 2022 – Q4 2023 24 months
Commercial Operation Power Block 2	Q1 2024
Demolish Units 1 and 2 to Turbine deck	Q1 2024 – Q4 2025 24 months

If the Amended HBEP is approved by the Energy Commission, construction and demolition activities at the project site are anticipated to take approximately 10 years, lasting through the fourth quarter of 2025. The amended application indicated a construction schedule for the various phases of activities with the CCGT phase I, power block 1, anticipated to begin in the second quarter of 2017 with commercial operation of power block 1 during the second quarter of 2020. Construction of the SCGT phase 2, power block 2, is anticipated to begin during the first quarter of 2022 with commercial operation during the first quarter of 2024.

Onsite parking and construction staging areas as approved under the Final Decision has been modified with a reduction of one parking area located along Pacific Coast Highway 1 between Beach Boulevard and Huntington Street.

The Final Decision required both onsite and offsite laydown and construction parking areas. Approximately 22 acres of construction laydown area and approximately 6 acres at the HBGS to be used for a combination of laydown and construction parking and 16 acres at the AES Alamitos Generating Station (AGS) used for construction laydown (component storage only with no assembly of components at AGS).

Approximately 300 onsite and offsite parking spaces were needed for both demolition workers and during construction. These parking spaces were identified at the following locations:

- Approximately 1.5 acres for 130 parking stalls located onsite, behind the Southern California Edison switchyard.
- Approximately 3 acres or approximately 300 parking spaces (existing paved/graveled parking) located adjacent to HBEP across Newland Street.
- Approximately 2.5 acres or approximately 215 existing paved parking stalls located at the corner of Pacific Coast Highway and Beach Boulevard; and
- The Plains All American site. Approximately 22 acres in size to be utilized for both construction parking and construction laydown areas. Parking spaces could range between 170 to 330 stalls depending on the construction laydown area required for each project construction and demolition phase.

Figure 2 “HBEP Construction Parking Areas” with both onsite and offsite locations. The amended parking areas and locations:

PROJECT DESCRIPTION - FIGURE 2

Amended Huntington Beach Energy Project - Construction / Laydown Parking Areas

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: CH2M - Figure 2.3-3 (Rev 1)

A new entrance to the Plains All American Tank Farm will be from a modified three way intersection at the existing Magnolia Street and Banning Avenue signalized intersection. The project owner is working with the city of Huntington Beach regarding improvements for the current three-way signalized intersection to a temporary four-way signalized intersection with a two lane entrance/exit at this modified intersection.

The PTA includes the use of a footbridge connecting the Plains All American site to the Amended HBEP site. The use of this footbridge would require the Project Owner to obtain appropriate easements from the landowner. Absent appropriate easements, construction worker access to the Amended HBEP construction site from the Plains Site would be via Pacific Coast Highway should the footbridge be unavailable; and construction workers will travel on shuttles from the Plains Site to the construction site via Pacific Coast Highway on the route identified in the PTA. (PTA, p. 2-14 to 2-15 (TN# 206087); Project Owner's Response to City of Huntington Beach Comments on PTA, Att. A (TN# 210262).

As with the Licensed HBEP, the Amended HBEP facility will be air-cooled, eliminating the need for large quantities of once-through cooling seawater. The minimal potable water necessary for HBEP's construction, operational process and sanitary purposes would be provided by the city of Huntington Beach, which has provided a will-serve letter indicating there is sufficient supply of potable water to accommodate the Amended HBEP. Alternative water sources, including potential use of reclaimed water to support the HBEP, were analyzed and determined to be infeasible. During operation, storm water and process wastewater would be discharged into a retention basin and then discharged to the ocean via the existing outfall. Discharge flows would substantially decrease compared to existing conditions due to decreased plant water use, and all discharges would meet ocean discharge standards. Sanitary wastewater would be conveyed to the Orange County Sanitation District through an existing sewer connection.

No offsite linear developments are proposed as part of this project. The amended HBEP would connect the 844 MW of electricity through two overhead 230-kilovolt (kV) generation ties connecting each power block to the existing onsite SCE Ellis switchyard. Natural gas is delivered to the HBGS via an existing SoCalGas16-inch diameter line to an existing gas metering station. As part of the HBEP project, a new gas metering station and new gas pressure control station would be constructed.

APPLICANT'S PROJECT PURPOSE AND OBJECTIVES

The amended AFC describes the applicant's objectives for the HBEP proposal, which are summarized as follows:

- Provide efficient, reliable and predictable power supply by using combined-cycle, natural gas-fired combustion turbines to replace the Once- Through Cooling (OTC) generation;
- With the closure of San Onofre Nuclear Generating Station, proposed facility provides replacement generation for southern California customers;
- Eliminate use of ocean water for once-through-cooling;

- Be able to support the local capacity requirements of Southern California's Western Los Angeles Basin;
- Develop a 844 MW power generation plant that provides efficient operational flexibility with rapid-start and fast ramping capability to allow for efficient integration of renewable energy sources in the California electrical grid;
- Reuse existing electrical, water, wastewater, and natural gas infrastructures and land to minimize land resource and environmental justice impacts by developing on an existing brown field site;
- Site the project to serve the load area without constructing new transmission facilities; and
- Site the project on property that has industrial land use designation with consistent zoning.

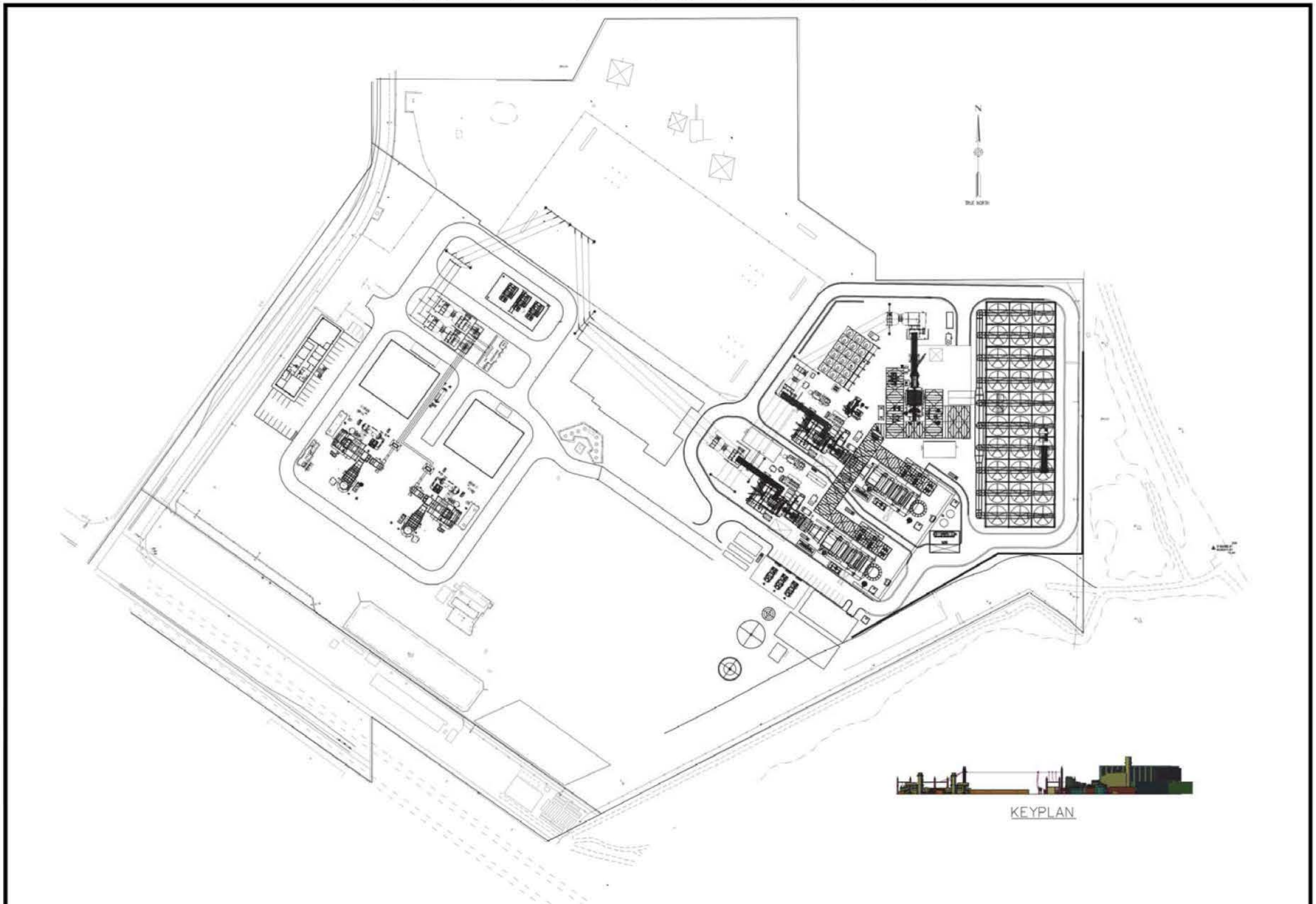
The HBEP would provide up to 844 MW of power generation capacity to the western Los Angeles Basin Local Reliability Area and will replace the retiring Huntington Beach Generating Station. The HBGS is scheduled to cease operation by December 31, 2020 in compliance with the California State Water Resources Control's Board's (SWRCB) *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.* This policy was adopted by the SWRCB on May 4, 2010*,* and regulates the use of seawater for power generation plants utilizing the OTC method.

PROJECT FEATURES

The main project features would consist of a 28.6-acre power plant site, which will require both onsite and offsite laydown and construction parking. Approximately 22 acres of construction laydown will be required, and a maximum of 300 parking sites. The power plant, transmission lines, SCE switchyard, and natural gas connection are located within the city of Huntington Beach within an area designated as Public, in which the Huntington Beach General Plan permits development of public utilities.

Project Description Figure 3, shows the general arrangement and layout of the proposed facility. The Visual Resources section of this PSA includes a number of visual simulations of the proposed project, before and after construction.

PROJECT DESCRIPTION - FIGURE 3
Huntington Beach Energy Project - General Arrangement/Site Plan



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: CH2MHill

The existing HBGS currently has five generating units. Units 1, 2, 3 and 4 are legacy boilers, using natural gas to heat the boilers to produce steam. Units 3 and 4 were converted to synchronous condensers in 2012. Unit 5 is a peaker (former gas turbine generator). Unit 5 demolition is scheduled to begin during the 1st quarter of 2016 to the 2nd quarter of 2017.

The demolition schedule of existing Units 3 and 4 will occur in advance of the construction of the Amended HBEP phase 2 SCGT power block. The demolition schedule for these Units is anticipated to begin during the 2nd quarter of 2020 through the 4th quarter of 2021 and are under a separate license through the California Energy Commission (CEC; 00-AFC-13C).

Existing Unit 1 will be retired in the fourth quarter of 2019 to provide interconnection capacity for the new CCGT units. Unit 2 will be retired either after commercial operation of the HBEP SCGT units or at the final compliance deadline for once-through-cooling intake structures as determined by the State Water Resources Control Board, after which demolition of Huntington Beach Generating Station Units 1 and 2 will commence. The Amendment indicates the demolition of Units 1 and 2 during the 1st quarter of 2024 through the 4th quarter of 2025.

Effective October 31, 2012, Units 3 and 4 ceased commercial operation, and the air emission credits transferred to the Walnut Creek Energy Park, a 500 MW generating facility located in City of Industry, California.

On September 7, 2012 the California ISO approved a must-run contract on Units 3 and 4 to convert to synchronous condensers to provide voltage support to southern Orange County and San Diego in response to the San Onofre Nuclear Generating Station units 2 and 3 being unavailable for the summer of 2013. A major amendment was approved by the Energy Commission on December 7, 2012, to convert Units 3 and 4 to synchronous condensers which provide voltage support. Unit 5, a 133 MW peak demand facility, was retired in 2002.

The existing HBGS has various ancillary facilities that will remain in use to support HBEP. These facilities include the administration/warehouse building, SoCalGas natural gas pipeline interconnection and metering station, City of Huntington Beach potable water connection and the City of Huntington Beach sanitary sewer system.

Natural gas is delivered via an existing SoCalGas16-inch diameter line to an existing gas metering station. As part of the HBEP project, a new gas metering station and new gas pressure control station will be constructed by the project owner.

The project will use potable water for construction and operational processes and sanitary uses. The water delivered to the HBEP site is supplied from an existing 8-inch pipeline from the City of Huntington Beach into a 442,500 gallon service water/fire water storage tank. This water will be used as plant service water, irrigation water, makeup water to the combustion turbine inlet air evaporative coolers, and raw feed to the steam cycle makeup water treatment system. The City of Huntington Beach has provided a will-serve letter indicating there is sufficient supply of potable water to accommodate the HBEP. Alternative water sources, including potential use of reclaimed water, to support the HBEP were analyzed and determined to be infeasible.

Makeup water for the HBEP power blocks steam cycle will have contaminants removed by passing the service water through a reverse osmosis system followed by a continuous electrodeionization process.

Sanitary wastewater generated by the HBEP will be discharged to the City of Huntington Beach existing 4-inch sewer main that services the existing HBGS. HBEP process wastewater and site storm water will be collected in an onsite retention basin then discharged to the Pacific Ocean via an existing outfall which services the existing HBGS.

The 442,500 gallon service water/fire water storage tank will provide approximately 35 hours of operational storage and 2 hours of fire protection storage in the event of a disruption in water supply. The existing fire water distribution system, including two emergency diesel-fired fire water pumps, storage tanks and piping, will remain in service as part of the fire protection system, but will be modified to meet all LORS for the HBEP and to accommodate the newly constructed facilities.

The construction laydown areas consist of 6 acres at the HBGS and 16 acres at the AGS in Long Beach, which will be used for component storage only; no assembly of components will take place at the AGS site. During construction, the large components will be hauled from the construction laydown area at the AGS site to the HBEP site as they are ready for installation.

Construction and demolition parking will be provided by a combination of onsite and offsite parking. A maximum of 300 parking spaces will be required during construction and demolition activities. Approximately 1.5 acres (130 parking spaces) will be provided onsite, 3 acres (300 parking spaces) adjacent to HBEP across Newland Street, 2.5 acres (215 parking spaces) at the corner of the Pacific Coast Highway (PCH) and Beach Boulevard, 225 parking spaces at the City of Huntington Beach shore parking, and 1.9 acres (170 parking spaces) at the Plains All American Tank Farm on Magnolia Street.

Two 230- kV transmission interconnections will connect HBEP power blocks 1 and 2 to the existing onsite SCE Ellis switchyard.

NOTEWORTHY PUBLIC BENEFITS

The California Independent System Operator (California ISO) has recognized the importance of the existing HBGS location in providing energy and contingency reserve for the Western Los Angeles Basin Local Reliability Area and northern San Diego County. Specifically, this location serves Orange County by providing essential electrical service to the existing SCE Ellis substation through a dedicated 230- kV transmission line connection. If approved by the Energy Commission, the HBEP will ensure the long-term viability of this existing critical generating location and will provide essential electrical service to the residents of Orange County and Huntington Beach. HBEP's quick-start peaking electric generation capacity will meet peak demand and resource adequacy requirements as identified by AB 380 (Resource Adequacy) and the California ISO.

The proposed HBEP will be air cooled, eliminate the use of OTC and the use of seawater currently being used at the HBGS, which is scheduled to retire by December 31, 2020. This will eliminate the use of ocean water at the power plant site and will eliminate the potential impacts to marine life through impingement and entrainment in an OTC system. In addition, the proposed HBEP will result in a substantial reduction in fresh water usage, using 20% of the fresh water used by the existing HBGS.

The HBEP will be located entirely within the footprint of the existing HBGS site, which will result in avoiding the need to construct new linear facilities, including gas and water supply lines, discharge lines and transmission interconnections. Siting the HBEP on the HBGS site is consistent with existing zoning regulations, and will result in reducing potential offsite environmental impacts, the cost of construction, and ensures no new site is converted to industrial use.

The design of the proposed HBEP is a smaller footprint and lower profile than the existing HBGS, which will be an improvement to the aesthetic quality of the project. Removal of an assemblage of structures, tanks, and cooling tower and replacement with project elements that are shorter and set back further to the north of the PCH will reduce some of the existing visual conditions. HBEP will utilize an existing power generation site with a General Plan Land Use designation of Public and a zoning designation of Public-Semipublic., consistent zoning, and electrical, water, wastewater, and natural gas infrastructure in place. Retiring the OTC system would minimize potential offsite environmental impacts, and the project would eliminate the need for a new site to be converted to Public-Semipublic use. In addition, the HBEP will replace an older, dirtier and less efficient power generation plant with a cleaner, more efficient power generation plant.

Environmental Assessment

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
AIR QUALITY
Wenjun Qian, Ph.D., P.E.

SUMMARY OF CONCLUSIONS

Staff concludes that with the adoption of the attached conditions of certification, the Amended Huntington Beach Energy Project (HBEP) would not result in significant air quality related impacts during project operation, and that the Amended HBEP would comply with all applicable federal, state and South Coast Air Quality Management District (SCAQMD) air quality laws, ordinances, regulations, and standards (LORS).

The proposed modifications include changing the turbine technology in one combined-cycle power block from Mitsubishi Heavy Industries 501DA three-on-one turbines to GE 7FA.05 two-on-one turbines with a nominal capacity of 644 megawatts (MW) net with an auxiliary boiler. The other power block would be changed to two GE LMS-100PB simple-cycle turbines with a nominal combined capacity of 200 MW. In accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that supplementation to the Energy Commission Final Decision is necessary for Air Quality. These proposed project changes constitute a considerable change in fact and circumstance from the 2014 Decision requiring a complete re-analysis of the project and air quality impacts.

Staff concludes that operating period mitigation would be provided in the form of Regional Clean Air Incentives Market (RECLAIM) Trading Credits (RTCs) and emission reduction credits (ERCs) as required by SCAQMD rules and that these measures would fully mitigate emissions of all nonattainment pollutants and their precursors at a minimum ratio of one-to-one. These mitigation measures reduce potential operational impacts of the proposed project to less than significant.

Staff includes the approved conditions of certification **AQ-SC1** through **AQ-SC5** to mitigate construction impacts. Compliance with these conditions is expected to greatly reduce or eliminate the potential for significant adverse air quality impacts during construction of the Amended HBEP. PM10 and PM2.5 impacts during the approximately 10-year project construction period would cause exceedances of health-based ambient air quality standards and thus these impacts would be significant unless mitigated. Staff recommends **AQ-SC6** to mitigate these potential impacts. The duration and complexity of construction that contributes to these potential impacts are due in part to the desire of the project owner and the California Independent System Operator to have continuity of generation and/or reactive power from the site. There would be concurrent construction/demolition, commissioning and operation activities throughout the construction period. For the licensed HBEP, California Energy Commission (Energy Commission) approved condition of certification **AQ-SC6** to further mitigate the PM emissions by using a local street sweeping program during the construction period (CEC 2014bb). For the Amended HBEP, staff proposes to revise condition of certification **AQ-SC6** according to the revised construction emissions, which would be less than those for the licensed HBEP.

Global climate change and greenhouse gas emissions from the Amended HBEP are discussed and analyzed in **Air Quality Appendix AIR-1**. The Amended HBEP would emit approximately 0.381 metric tonnes of carbon dioxide per megawatt hour ($MTCO_2$/MWh), which would comply with Greenhouse Gases Emission Performance Standard of 0.5 $MTCO_2$/MWh (Title 20, California Code of Regulations, section 2900 et seq.). The Amended HBEP would be subject to federal mandatory reporting of GHG emissions. The facility owner may have to provide additional reports and GHG reductions, depending on the future regulations formulated by the U.S. EPA or the ARB.

The proposed GE 7FA.05 combined-cycle turbines are 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 CO_2/MWh, gross) or (1,030 lb CO_2/ MWh, net) for new base load natural gas fueled turbines. The proposed GE LMS-100PB simple-cycle turbines are expected to comply with the limit of 120 lb CO_2 per million Btus (MMBtu) of natural gas heat input for new non-base load natural gas fueled turbines. Should the combined-cycle turbines operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. No specific GHG conditions of certification are proposed in the **Appendix AIR-1**, but **AQ-14** and **AQ-58** would ensure compliance with the new federal standards.

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants from the demolition of the existing Huntington Beach Generating Station (HBGS) units and the construction and operation of the Amended HBEP project.

The Amended HBEP would be a natural-gas-fired, combined-cycle and simple-cycle, air-cooled electrical generating facility located on the site of the existing HBGS in Huntington Beach, California. The combined-cycle power block would consist of a two-on-one combined-cycle unit with two GE Frame 7FA.05 gas turbines, two unfired heat recovery steam generators (HRSGs), one steam turbine generator, one air-cooled condenser, one natural-gas-fired auxiliary boiler, and related ancillary equipment. The simple-cycle power block would include two GE LMS-100PB simple-cycle turbines and their separate ancillary equipment. The existing two emergency diesel fire water pumps installed at the Huntington Beach Generating Station will remain in service for the Amended HBEP under SCAQMD permits.

As with the licensed HBEP, construction of the Amended HBEP would require removal of the existing HBGS Unit 5 (for the combined-cycle power block) and Units 3 and 4 (for the simple-cycle power block). Removal/demolition of existing HBGS Units 1 and 2 is not specifically required, but will be completed voluntarily by the project owner.

Criteria air pollutants are defined as air contaminants for which the state and/or federal government has established an ambient air quality standard to protect public health. The criteria pollutants analyzed are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), inhalable particulate matter (PM10), and fine particulate matter (PM2.5). In addition, emissions of nitrogen oxides (NOx, consisting primarily of nitric oxide [NO] and NO_2), sulfur oxides (SOx) and volatile organic compounds (VOC) are also analyzed. NOx and VOC readily react in the atmosphere as precursors to ozone. NOx and SOx also readily react in the atmosphere to form particulate matter, and are contributors to acid rain. Global climate change and greenhouse gas (GHG) emissions from the Amended HBEP are discussed and analyzed in the context of cumulative impacts (**Air Quality Appendix AIR-1**).

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

- Whether the Amended HBEP is likely to conform with applicable federal, state, and SCAQMD air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1742 (d));
- Whether the Amended HBEP 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 1744.5); and
- Whether the mitigation measures proposed for the amended project are adequate to lessen the potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

SUMMARY OF THE DECISION

On October 29, 2014, the Energy Commission approved the HBEP as a 939 MW (nominal output) combined cycle power plant with two power blocks. Each power block would consist of three Mitsubishi Heavy Industries 501DA gas turbine generators coupled with one steam turbine, in a combined cycle configuration. The Final Commission Decision (CEC 2014bb) of HBEP concluded that with the implementation of mitigation measures described in the record and contained in the conditions of certification, HBEP would conform with all applicable laws, ordinances, regulations, and standards relating to air quality, and would not result in significant direct, indirect, or cumulative air quality impacts in conformance with CEQA requirements.

The original decision included 8 staff conditions and 43 conditions proposed by the SCAQMD.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The following federal, state, and local LORS and policies pertain to the control of criteria pollutant emissions and the mitigation of air quality impacts. Staff's analysis describes or evaluates compliance of the Amended HBEP with these requirements, as in **Air Quality Table 1**. The major updates of the LORS for the Amended HBEP from those identified previously for the licensed HBEP would be:

- The licensed HBEP was subject to Title 40 CFR Part 60, Subpart Da Standards of Performance for Electric Utility Steam Generating Units because of the licensed fired HRSGs. The Amended HBEP would have unfired HRSGs, thus would not be subject to Title 40 CFR Part 60, Subpart Da.
- The currently proposed auxiliary boiler would be subject to Title 40 CFR Part 60, Subpart Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, SCAQMD Rule 404 – Particulate Matter Concentration, and SCAQMD Rule 1146 – Emissions of Oxides of Nitrogen from Boilers. The licensed HBEP did not include an auxiliary boiler and thus was not subject to these rules/regulations.
- On August 3, 2015, U.S. EPA finalized a rule under Clean Air Act section 111(b) that would limit carbon dioxide emissions from new, modified and reconstructed stationary turbines. The Amended HBEP would be subject to this new rule. The licensed HBEP was approved before the rule was finalized. More details are discussed in **Air Quality Appendix AIR-1**.

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

Applicable LORS	Description
Federal	**U.S. Environmental Protection Agency**
Title 40 CFR Part 51 (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of specified stationary sources. NSR applies to sources of designated nonattainment pollutants. This requirement is addressed through SCAQMD Regulation XIII.
Title 40 CFR Part 52 (Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of pollutants that occur at ambient concentrations that attain the National Ambient Air Quality Standards (NAAQS). The emissions of CO and NOx of the Amended HBEP would exceed the 100 tons per year (tpy) threshold per pollutant, thus the Amended HBEP would be subject to PSD analysis requirements for CO and NOx. The Amended HBEP would also be a new major stationary source of GHG (exceeding 100,000 tons per year) which requires a PSD permit for GHGs. The PSD program was initially within the jurisdiction of the U.S. EPA. On January 9, 2013, SCAQMD became the agency responsible for the issuance of GHG PSD permits for sources within the SCAQMD.

Applicable LORS	Description
Title 40 CFR Part 60, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)	Applies to steam generating units with design heat input rates between 10 and 100 MMBtu/hr that were installed after June 9, 1989. The proposed 71 MMBtu/hr auxiliary boiler would be subject to this regulation.
Title 40 CFR Part 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)	New Source Performance Standard (NSPS) for Steam Generators. For the fired HRSGs which are greater than the 250 MMBtu/hr, the emission standards are NOx 0.2 lbs/ MMBtu, PM 0.015 lbs/ MMBtu, and SO_2 0.2 lbs/ MMBtu.
Title 40 CFR Part 64 (Compliance Assurance Monitoring [CAM])	The CAM regulation applies to emission units at major stationary sources required to obtain a Title V permit, which use control equipment to achieve a specified emission limit and which have emissions that are at least 100 percent of the major source thresholds on a pre-control basis. The rule is intended to provide “reasonable assurance” that the control systems are operating properly to maintain compliance with the emission limits.
Title 40 CFR Part 72	Acid Rain Program. Requires reductions in NOx and SO_2 emissions, implemented through the Title V program.
State	**California Air Resources Board and Energy Commission**
California Health & Safety Code (H&SC) §41700 (Nuisance Regulation)	Prohibits discharge of such quantities of air contaminants that cause injury, detriment, nuisance, or annoyance.
H&SC §40910-40930	Permitting of source needs to be consistent with approved clean air plan.
California Public Resources Code §25523(a); 2300-2309 (CEC & ARB Memorandum of Understanding)	Requires that Energy Commission decision on an application for certification include requirements to assure protection of environmental quality. The Petition to Amend (PTA) is required to include information concerning air quality protection.
HSC Sections 21080, 39619.8,40440.14 (AB1318)	Requires the executive officer of the SCAQMD, upon making a specified finding, to transfer emission reduction credits for certain pollutants from the SCAQMD’s internal emission credit accounts to eligible electrical generating facilities.
Local	**South Coast Air Quality Management District**
Regulation II – Permits	This regulation sets forth the regulatory framework of the application for issuance of construction and operation permits for new, altered and existing equipment.
Regulation IV – Prohibitions	This regulation sets forth the restrictions for visible emissions, odor nuisance, fugitive dust, various air emissions, and fuel contaminants. This regulation also specifies additional performance standards for stationary gas turbines and other internal combustion engines.
Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	This rule applies to boilers, steam generators, and process heaters of equal to or greater than 5 million Btu per hour rated heat input capacity used in all industrial, institutional, and commercial operations with the exception of: (1) boilers used by electric utilities to generate electricity; and (2) boilers and process heaters with a rated heat input capacity greater than 40 million Btu per hour that are used in petroleum refineries; (3) sulfur plant reaction boilers; and (4) RECLAIM facilities (NOx emissions only).

Applicable LORS	Description
Regulation XIII: New Source Review for Non-RECLAIM Pollutants	Establishes the pre-construction review requirements for new, modified or relocated facilities to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards and that future economic growth in the SCAQMD is not unnecessarily restricted. However, this regulation does not apply to NOx or SOx emissions from certain sources, which are addressed by Regulation XX (RECLAIM).
Regulation XVII: Prevention of Significant Deterioration	This regulation sets forth the preconstruction requirement for stationary sources to ensure that the air quality in clean air areas does not significantly deteriorate while maintaining a margin for future industrial growth.
Regulation XX: Regional Clean Air Incentives Market (RECLAIM)	RECLAIM is designed to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx through controls, equipment modifications, reformulated products, operational changes, shutdowns, other reasonable mitigation measures or the purchase of excess emission reductions.
Regulation XXX: Title V Permits	The Title V federal program is the air pollution control permit system required by the federal Clean Air Act as amended in 1990. Regulation XXX defines the permit application and issuance as well as compliance requirements associated with the program. Any new or modified major source which qualifies as a Title V facility must obtain a Title V permit prior to construction, operation or modification of that source. Regulation XXX also integrates the Title V permit with the RECLAIM program such that a project cannot proceed without both.
Regulation XXXI: Acid Rain Permits	Title IV of the federal Clean Air Act provides for the issuance of acid rain permits for qualifying facilities. Regulation XXXI integrates the Title V program with the RECLAIM program. Regulation XXXI requires a subject facility to obtain emission allowances for SOx emissions as well as monitoring SOx, NOx, and carbon dioxide (CO_2) emissions from the facility.

COMPLIANCE WITH LORS

The Preliminary Determination of Compliance (PDOC) for Amended HBEP was docketed on June 8, 2016 (SCAQMD 2016b). Compliance with all SCAQMD Rules and Regulations was demonstrated to the SCAQMD's satisfaction in the PDOC, and the draft permit conditions are presented in the Conditions of Certification located near the end of this section. At the time of this analysis, SCAQMD's Final Determination of Compliance (FDOC) is not available. Therefore the conditions of certification are subject to change upon the release of FDOC.

FEDERAL

40 CFR 51, Nonattainment New Source Review. The PDOC includes conditions that would implement the federal nonattainment New Source Review (NSR) permit for the Amended HBEP.

40 CFR 52, Prevention of Significant Deterioration. The Amended HBEP project is subject to permit requirements under the PSD program, which is administered by the SCAQMD. The facility owner submitted the PSD application to the SCAQMD in September 2015.

40 CFR 60 Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This performance standard applies to steam generators rated between 10 and 100 MMBtu/hr constructed after June 9, 1989. However, the emission limits are only applicable to coal or oil fired units. Since the auxiliary boiler would be fired on natural gas exclusively, only records of the amount of fuel combusted on a monthly basis are required.

40 CFR 60 Subpart KKKK, NSPS for Stationary Gas Turbines. The turbines are subject to Subpart KKKK because their heat input is greater than 10.7 gigajoules per hour (gigajoules/hr) or 10 MMBtu per hour (MMBtu/hr) at peak load, based on the higher heating value of the fuel fired. Actual unit rating is 2,273 MMBtu/hr (2,398.0 gigajoules/hr) for the combined-cycle turbines and 885 MMBtu/hr (933.7 gigajoules/hr) for the simple-cycle turbines. The standards applicable for a natural gas turbine greater than 850 MMBtu/hr are: NOx 15 parts per million (ppm) at 15 percent O_2 (0.43 lbs/MWh), SOx: 0.90 lbs/MWh discharge into the atmosphere, or the fuel contains total potential sulfur emissions of 0.060 lbs/MMBtu heat input. In addition, this regulation requires that the fuel consumption and water to fuel ratio be monitored and recorded on a continuous basis, or alternatively, that a NOx and O_2 CEMS be installed. For the SOx requirement, either a fuel meter to measure input, or a watt-meter to measure output is required, depending on which limit is selected. Also, daily monitoring of the sulfur content of the fuel is required if the fuel limit is selected. However, if the operator can provide supplier data showing the sulfur content of the fuel is less than 20 grains/100 cf (for natural gas), then daily fuel monitoring is not required. An initial performance test is required for both NOx and SO_2. For units with a NOx CEMS, a minimum of 9 RATA reference method runs is required at an operating load of +/- 25 percent to 100 percent of load. For SO_2, either a fuel sample methodology or a stack measurement can be used, depending on the chosen limit. Annual performance tests are also required for NOx and SO_2. Compliance with the requirements of this rule is expected.

40 CFR Part 64, Compliance Assurance Monitoring (CAM). The CAM regulation applies to emission units at major stationary sources required to obtain a Title V permit, which use control equipment to achieve a specified emission limit and which have emissions that are at least 100 percent of the major source thresholds on a pre-control basis. The facility is a major source. The combined-cycle turbines' pre-control emissions would be greater than the major source thresholds for NOx, CO, and VOC. The combined-cycle turbines would be subject to an emission limit for each of these pollutants, and would use control systems to meet these limits. The simple-cycle turbines' pre-control emissions would be greater than the major source threshold for NOx and CO. The simple-cycle turbines would be subject to an emission limit for each of these pollutants, and would use control systems to meet these limits. The auxiliary boiler pre-control emissions would not trigger the thresholds for any pollutant.

NOx emissions from the proposed turbines would be controlled with the selective catalytic reduction system. As a NOx Major Source under RECLAIM, the turbines are required to have CEMS under Rule 2012. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM requirements under 64.2(b)(vi).

CO emissions from the proposed turbines would be controlled with the oxidation catalyst. The turbines would be required to use a CO Continuous Emission Monitoring System (CEMS) under Rule 218. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM requirements under 64.2(b)(vi).

VOC emissions would also be controlled with the oxidation catalysts. The oxidation catalysts are effective at operating temperatures above certain temperatures. The facility is required to maintain a temperature gauge in the exhaust of the combined-cycle turbines, which will measure the exhaust temperature on a continuous basis and record the readings on an hourly basis. The exhaust temperature is required to be at least 570°F for the oxidation catalysts of the combined-cycle turbines (with exceptions for start ups and shutdowns [**AQ-34** or SCAQMD condition D12.10]). This will ensure that the oxidation catalyst is operating properly. Compliance is expected.

40 CFR Part 72, Acid Rain Provisions. The Amended HBEP would be subject to the requirements of the federal acid rain program, because the turbines would be rated at greater than 25 MW. The acid rain program is similar to RECLAIM in that facilities are required to cover SO_2 emissions with “SO_2 allowances” that are similar in concept to RTCs. The Huntington Beach facility was given initial allowance allocations based on the past operation of their boilers. The project owner can either use those allocations, or if insufficient, must purchase additional allocations to cover the operation of the Amended HBEP. The project owner is also required to monitor SO_2 emissions through use of fuel gas meters and gas constituent analyses, or, if fired with pipeline quality natural gas, as in the case of the Amended HBEP, a default emission factor of 0.0006 lbs/MMBtu is allowed. SO_2 mass emissions are to be recorded every hour. NOx and O_2 must be monitored with CEMS in accordance with the specifications of Part 75. Under this program, NOx and SOx emissions will be reported directly to the U.S. EPA. Part 75 requires that the CEMS be installed and certified within 90 days of initial startup. Compliance is expected.

STATE

The project owner has demonstrated that the Amended HBEP would comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury. Conditions required in the SCAQMD’s PDOC (SCAQMD 2016b) and the Energy Commission staff’s Conditions of Certification enable staff’s affirmative finding.

LOCAL

The project owner provided an air quality permit application to the SCAQMD and the SCAQMD has issued a PDOC (SCAQMD 2016b), which states that the Amended HBEP is expected to comply with all applicable SCAQMD rules and regulations. The SCAQMD will also issue a final determination of compliance (FDOC) after considering comments submitted during the comment period.

The SCAQMD rules and regulations specify the emissions control and offset requirements for new sources such as the Amended HBEP. Best Available Control Technology would be implemented, and RTCs for NOx and SOx emissions are required by SCAQMD rules and regulations based on the permitted emission levels for the Amended HBEP. Compliance with the SCAQMD's new source requirements would ensure that the Amended HBEP would be consistent with the strategies and future emissions anticipated under the SCAQMD's air quality attainment and maintenance plans.

As part of the Energy Commission's licensing process, in lieu of issuing a construction permit to the project owner for the Amended HBEP, the SCAQMD has prepared and presented to the Energy Commission the PDOC, and will issue the FDOC after a public comment period. The DOCs evaluate whether and under what conditions the Amended HBEP would comply with the SCAQMD's applicable rules and regulations, as described below.

Compliance with specific SCAQMD rules and regulations is discussed below via excerpts from the PDOC (SCAQMD 2016b) with staff's edits if necessary. For a more detailed discussion of the compliance of the Amended HBEP, please refer to the PDOC (SCAQMD 2016a).

Regulation II – Permits

RULE 212 – Standards for Approving Permits. The Amended HBEP is subject to Rule 212 public notice requirements because the daily maximum VOC, CO, NOx, and PM10 emissions from the Amended HBEP would all exceed the emissions thresholds specified in subdivision (g) of this rule. The SCAQMD has prepared a public notice which contains sufficient information to fully describe the project. In accordance with subdivision (d) of this rule, the project owner will be required to distribute the public notice to each address within ¼ mile radius of the project.

RULE 218 – Continuous Emission Monitoring System (CEMS). In order to ensure the equipment meets the CO BACT limit as specified in the permit, a CO CEMS will be required by permit condition. The CO CEMS must be certified in accordance with Rule 218. The rule requires submittal of an "Application for CEMS" for approval. Once approved, CEMS data must be recorded and records of the data must be maintained on site for at least 2 years. Additionally, every 6 months a summary of the CEMS data must be submitted to SCAQMD. Any CEMS breakdowns must also be reported. Compliance with this rule is expected. The auxiliary boiler will not be required to have a CO CEMS. NOx CEMS requirement is described below under Rule 2012.

Regulation IV – Prohibitions

RULE 401 – Visible Emissions. This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. Visible emissions are not expected during normal operation from the turbines, the auxiliary boiler, oil/water separators, or ammonia tanks.

RULE 402 – Nuisance. This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The turbines, the auxiliary boiler, oil/water separators, and ammonia tanks are not expected to create nuisance problems under normal operating conditions.

RULE 403 – Fugitive Dust. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The project owner will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. In addition, the project owner will need to implement all Best Available Control Measures listed in Table 1 of the rule. The installation and operation of the turbines and associated equipment is expected to comply with this rule.

RULE 404 – Particulate Matter Concentration. This rule applies to the auxiliary boiler. Turbines are exempt under paragraph (c) of the rule. The rule limits the PM concentration based on the stack flow. At maximum firing rate, the SCAQMD estimated the auxiliary boiler stack flow to be 12,059 cubic feet per minute (cfm). Therefore, the corresponding maximum allowable PM concentration is 0.073 grains per cubic foot (gr/scf). The SCAQMD estimated the PM concentration for the auxiliary boiler to be 0.0049 gr/scf. Therefore, compliance with this rule is expected.

RULE 407 – Liquid and Gaseous Air Contaminants. This rule limits CO emissions to 2000 ppmv. The CO emissions would be controlled by an oxidation catalyst to 2.0 ppmvd and 4.0 ppmvd at 15 percent O_2 for the GE 7FA.05 combined-cycle turbines and the GE LMS-100PB simple-cycle turbines respectively. The CO emissions from the auxiliary boiler would be maintained at 50 ppmvd at 3 percent O_2. Therefore, compliance with this rule is expected.

RULE 409 – Combustion Contaminants. This rule restricts the discharge of contaminants from the combustion of fuel to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12 percent CO_2, averaged over 15 minutes. The GE 7FA.05 combined-cycle turbines would have a grain loading of 0.002 gr/scf. The GE LMS-100PB simple-cycle turbines would have a grain loading of 0.004 gr/scf. The auxiliary boiler would have a grain loading of 0.014 gr/scf. Compliance with this rule is expected and will be verified through the initial performance test.

RULE 431.1 – Sulfur Content of Gaseous Fuels. The natural gas supplied to the Amended HBEP is expected to comply with the 16 ppmv sulfur limit (calculated as H_2S) specified in this rule. Commercial grade natural gas has an average sulfur content of about 4 ppm. The long term (annual) SOx emissions from the Amended HBEP are based on 4 ppm or about 0.25 grains per 100 cubic feet concentration (gr/100 cf). The short term (hourly, daily, and monthly) SOx emissions from the Amended HBEP are based on 12 ppm or about 0.75 gr/100 cf. The project owner will also comply with reporting and record keeping requirements as outlined in subdivision (e) of this rule.

RULE 475 – Electric Power Generating Equipment. This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meets a limit for combustion contaminants of 11 pounds per hour (lbs/hr) or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from each GE 7FA.05 turbine are estimated at 8.5 lbs/hr, and 0.0026 gr/scf at maximum firing load. Mass PM10 emissions from each GE LMS-100PB turbine are estimated at 6.24 lbs/hr, and 0.0049 gr/scf at maximum firing load. Therefore, compliance is expected. Compliance will be verified through the initial performance test as well as ongoing periodic testing.

RULE 1146 – NOx from Boilers. This rule applies to boilers over 5 MMBtu/hr. Emission limits are 9 ppm NOx for gas firing, and 400 ppm CO. The emissions of the auxiliary boiler would be maintained at 5 ppmvd of NOx and 50 ppmvd of CO at 3 percent O_2. Under the rule, the unit must be tested periodically using a portable analyzer method every 750 operating hours, or monthly, whichever occurs later. If 3 consecutive tests show compliance without adjustment to the oxygen sensor set points, then the periodic tests are only required every 2,000 hours or quarterly. Furthermore, for boilers greater than 10 MMBtu/hr, a stack test using the reference methods is required every 3 years. Since the facility is subject to NOx RECLAIM, only the CO limits are applicable to the auxiliary boiler, and the periodic monitoring and stack testing is only required for CO. Compliance is expected.

Regulation XIII – New Source Review (NSR)

The new emission sources are subject to NSR, including Best Available Control Technology (BACT), modeling, and offsets. Also, the Amended HBEP is considered a major modification to an existing major source. Therefore, the additional requirements for major sources are applicable.

Best Available Control Technology (BACT)

BACT is required for all criteria pollutants and ammonia. For major sources, BACT is determined at the time the permit is issued, and is the Lowest Achievable Emission Rate (LAER), which has been Achieved in Practice. SCAQMD has determined that BACT for combined-cycle gas turbines is: NOx 2.0 ppmvd @ 15 percent O_2, one hour average; CO 2.0 ppmvd @ 15 percent O_2, one hour average; VOC 2.0 ppmvd @ 15 percent O_2, one hour average; PM10 natural gas fuel; SOx natural gas fuel with fuel sulfur content of no more than one grain/100 scf (about 16 ppm); NH_3 5.0 ppmvd @ 15 percent O_2, one hour average. SCAQMD has determined that BACT for simple-cycle turbines is: NOx 2.5 ppmvd @ 15 percent O_2, one hour average; CO 4.0 ppmvd @ 15 percent O_2, one hour average; VOC 2.0 ppmvd @ 15 percent O_2, one hour average; PM10 natural gas fuel; SOx natural gas fuel with fuel sulfur content of no more than one grain/100 scf (about 16 ppm); NH_3 5.0 ppmvd @ 15 percent O_2, one hour average. SCAQMD has determined that the BACT for the auxiliary boiler is: NOx 5.0 ppmvd, @ 3 percent O_2, one hour average; CO 100 ppmvd @ 3 percent O_2; PM10 natural gas fuel; SOx natural gas fuel; NH_3 5.0 ppmvd @ 3 percent O_2. Compliance is verified in the DOC.

Modeling

The project owner performed dispersion modeling for NO_2, CO, SO_2, and PM. Modeling evaluations were performed using the American Meteorological Society/Environmental Protection Agency Regulatory Model known as AERMOD (version 15181) and representative meteorological data from the John Wayne Airport meteorological station. Modeling analysis was performed for startups/shutdowns, normal operations, and commissioning of the turbines and the auxiliary boiler.

The SCAQMD's compliance determination for NO_2, CO, and SO_2 is a comparison of the project impact plus the background concentration to show that the sum does not exceed the ambient air quality standard. For PM10, the project impact should not exceed the Significant Increment. The results of the modeling analysis show that the Amended HBEP will not cause an exceedance, or make significantly worse an existing violation, of any state or national ambient air quality standard.

Offsets

The project owner is requesting that the Amended HBEP be evaluated under the Rule 1304(a)(2) – Electric Utility Steam Boiler Replacement exemption. This provision applies to the replacement of a utility steam boiler with combined cycle gas turbine(s), advanced gas turbines (including intercooled turbines) or renewables, and allows an exemption from the criteria pollutant modeling required under Rule 1303(b)(1), and from offsets for non-RECLAIM pollutants required under Rule 1303(b)(2) in such cases. The exemption applies on a MW to MW basis. Its purpose is to facilitate the removal of older, less efficient boiler/steam turbine technology with newer, cleaner gas turbine technology at the utilities, in conjunction with Rule 1135. Since the advent of RECLAIM, the exemption was expanded to include modifications being conducted in order to comply with Regulation XX rules. Rule 2005 does not provide a similar exemption for NOx.

In order to qualify for the Rule 1304(a)(2) exemption, the project owner is proposing to shut down HBGS Units 1 and 2 and Redondo Beach Generating Station (RBGS) Unit 7. The capacity of each of the HBGS Units 1 and 2 is 215 MW gross. The capacity of RBGS Unit 7 is 480 MW gross. The total capacity of the units being shutdown would be 910 MW gross. The total power generating capacity from the proposed new units would be 895.5 MW gross. The capacity of the units being shutdown is sufficient to cover the capacity of the new units, therefore, the new units qualify for the offset and modeling exemption.

Note that the new turbines' emission increases for PM10 and VOC will be accounted for through SCAQMD's internal offset 'bank', under the provisions of Rule 1304.1. Offsets for CO are not required, since CO is in attainment. NOx and SOx emissions are covered under RECLAIM.

The emissions from the auxiliary boiler and oil/water separators do not fall under the utility boiler replacement exemption. The project owner is required to provide offsets for non-RECLAIM pollutants VOC and PM10 for the auxiliary boiler and oil/water separators in the form of ERCs (offsets for CO emissions are not required). For the auxiliary boiler, the project owner is required to provide offsets for 4 lbs/day of VOC and 5 lbs/day of PM10. For the oil/water separators, the project owner is required to provide offsets for 1 lb/day of VOC.

Under Rule 2005, RTCs to cover the expected emissions of NOx are required to be held for the first compliance year. Additionally, since the NOx potential to emit (PTE) after the commissioning year is less than the facility's initial allocation (1,276,547 lbs/yr [SCAQMD 2016b]), the facility is not required to hold NOx RTCs for subsequent years. But the SCAQMD will make sure the facility has enough NOx RTCs for its actual emissions. The Huntington Beach facility is also in the SOx RECLAIM program. Therefore, SOx RTCs are required to be held to cover the first year of operation. Additionally, because the facility opted into SOx RECLAIM after 1994, there is no initial allocation. For this reason, SOx RTCs are required to be held for each compliance year after the first year of operation [paragraph (f)(1)].

Other requirements of RULE 1303:

Sensitive Zone Requirements. For this project, ERCs may be obtained from Zone 1 only.

Facility Compliance. The existing facility is currently in compliance with all applicable rules and regulations of the SCAQMD.

Alternative Analysis**.** The project is subject to the California Energy Commission licensing procedure. Under this procedure, a full analysis of the proposal is conducted, including project alternatives. Please refer the Alternative section of staff assessment for details.

Protection of Visibility**.** Net Increase in emissions from the proposed project exceed the 15 tons per year PM10 and 40 tons per year NOx thresholds, but the site is not within the specified distance of any Class I areas. However, a visibility analysis was conducted under the PSD regulation.

Statewide Compliance**.** The project owner has submitted a statement certifying that all AES's stationary sources are currently in compliance with applicable state and federal environmental regulations.

RULE 1304.1 – Electrical Generating Facility Fee for Use of Offset Exemption. The Amended HBEP would utilize the offset exemption of Rule 1304(a)(2) for PM10 and VOC, and is therefore subject to a fee under this rule. The facility has opted to pay an annual fee. The facility would be required to demonstrate compliance with the specific requirements of this rule prior to issuance of Permits to Construct for the Amended HBEP.

RULE 1325 – Federal PM2.5 New Source Review. Rule 1325 is the NSR rule for PM2.5 and its precursors, NOx and SO_2. This rule applies to new major polluting facilities, major modifications to existing major polluting facilities, and any modification to an existing facility that would constitute a major polluting facility in and of itself. A major polluting facility is defined as a facility located in a federal non-attainment area for PM2.5 which has actual emissions, or a potential to emit of greater than 100 tons per year, of either PM2.5 or its precursors. Note that on December 22, 2015, the U.S. EPA re-classified the South Coast basin as serious non-attainment for PM2.5. This effectively reduces the major source threshold from 100 tons per year to 70 tons per year. However, the reclassification does not take effect until August 14, 2017, or earlier if SCAQMD adopts the revised threshold by amending this rule prior to that date.

A major modification is defined as any physical change or change in the method of operation at a major source which results in a significant PM2.5 emission increase and a significant net emissions increase. If subject to this subpart, the facility is required to comply with the following requirements: 1) use lowest achievable emissions rate (LAER), 2) offset PM2.5 emissions at the applicable offset ratio, 3) certification of compliance with emission limits for all major sources under common control, and 4) conduct an alternatives analysis of the project. The existing facility is not a major source for PM2.5 and SO_2, but is a major source for NOx, which is a PM2.5 precursor. The Amended HBEP is considered a major modification to an existing major source for NO_2 and is subject to NSR under this rule for NOx only. The Amended HBEP is also considered a major modification for NOx under SCAQMD Rule 2005 and Regulation XVII (PSD), and as such, all of the requirements listed above are addressed under those rules. The total PM2.5 potential to emit of 69.6 tons/year from the Amended HBEP would not result in an emissions increase above the 100 tons/year threshold (or 70 tons/year after August 14, 2017 or earlier if the SCAQMD adopts the revised threshold by amending this rule prior to that date). Therefore, the Amended HBEP will continue to be a non-major polluting facility for PM2.5 and would not be subject to these requirements.

Regulation XVII – Prevention of Significant Deterioration (PSD)

The South Coast Basin where the project would be located is in attainment for NO_2, SO_2, CO, and PM10 emissions. Additionally, beginning on January 2, 2011, Greenhouse Gases (GHGs) are a regulated pollutant under the PSD major source permitting program. Therefore each of these pollutants must be evaluated under PSD requirements for this project.

The project owner performed a top-down BACT analysis for all criteria pollutants. The results of the BACT analysis are shown above under **Regulation XIII – New Source Review (NSR)**.

The project owner performed modeling which indicated that the maximum 1-hour CO, 8-hour CO, annual NO_2, 24-hour PM10, and annual PM10 impacts from operations of the Amended HBEP would be below the corresponding U.S. EPA Class II Significant Impact Levels (SILs). Therefore, additional analysis of 1-hour CO, 8-hour CO, annual NO_2, 24-hour PM10, and annual PM10 impacts is not required.

For 1-hour NO_2 impacts, it was determined that the peak impact level from the Amended HBEP exceeds the significance impact level of 7.52 micrograms per cubic meter ($\mu g/m^3$). Therefore, a cumulative NO_2 impact assessment is necessary. For the cumulative impact assessment, HBGS Units 1 and 2, Orange County Sanitation District's Huntington Beach and Fountain Valley facilities, Beta Offshore, as well as emissions from shipping lane activities off the coast were selected to be included based on their facility emissions and distance to the project. Seasonal, by hour-of-day background concentrations from the Costa Mesa monitoring station were used in the modeling. The 5-year average of 98^{th} percentile daily maximum 1-hour NO_2 impact from the project and the cumulative sources plus background would be 144 $\mu g/m^3$ (or 148 $\mu g/m^3$ for the worst year), which is less than the federal 1-hour standard of 188 $\mu g/m^3$. Therefore, no additional PSD analysis is necessary.

Visibility Analysis

The SCAQMD determined that modeling of visibility and deposition impacts to Class I areas is not necessary. Currently, there are no thresholds for visibility impacts on Class II areas. Using the criteria and thresholds for visibility impacts on Class I areas, the project owner found that the color contrast (ΔE) for Crystal Cove and Huntington Beach State Parks exceeded the thresholds using the Level I VISCREEN analysis. Therefore, the project owner performed a Level 2 VISCREEN analysis for these 2 areas. Using the Level 2 VISCREEN analysis, the project's impacts for both contrast and ΔE are less than the thresholds for Crystal Cove State Park but exceed the thresholds for Huntington Beach State Park. However, it should be noted that U.S. EPA requires, for informational purposes only, a visibility analysis of Class II areas using the Class I visibility thresholds and the VISCREEN model. This does not necessarily mean that permitting actions or project mitigation are required for any significant Class II visibility impacts that are found.

Soil and Vegetation Analysis

The project owner found that the project impacts do not exceed the secondary NAAQS and concluded that there will be no significant impacts to soil and vegetation. The modeling was reviewed by SCAQMD modeling staff and deemed acceptable. The application documents and modeling files were forwarded to the Federal Land Managers (US Forest Service and National Park Service) on January 6, 2016 to provide these agencies the opportunity to review and comment on the potential impacts of the proposed project on Class I areas. SCAQMD will not issue a final permit to AES until the land managers have issued their determinations.

Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

RULE 2011 – SOx RECLAIM, Monitoring Recording and Recordkeeping Requirements. The turbines and the auxiliary boiler will be classified as process units under SOx RECLAIM. As such they are required to measure and record fuel use and calculate mass SOx emissions using the emission factor on the permit, and electronically report emissions on a quarterly basis.

RULE 2012 – NOx RECLAIM, Monitoring Recording and Recordkeeping Requirements. The turbines and the auxiliary boiler will be classified as major NOx sources under NOx RECLAIM. As such, they are required to measure and record NOx concentrations and calculate mass NOx emissions with a Continuous Emission Monitoring System (CEMS). The CEMS would include in-stack NOx and O_2 analyzers, a fuel meter, and a data recording and handling system. NOx emissions are to be reported to SCAQMD on a daily basis. The CEMS system would be required to be installed within 90 days of start up. Compliance is expected.

Regulation XXX – Title V

The existing Huntington Beach facility is currently subject to Title V requirements, and is operating under a valid Title V permit issued on April 29, 2016. The addition of the combined cycle/simple cycle plant and auxiliary equipment would be considered a significant revision to the existing Title V permit. AES has submitted a Title V revision application A/N 578087. As a significant revision, the permit is subject to a 30-day public notice and a 45-day U.S. EPA review and comment period. On June 8, 2016, the Energy Commission docketed the SCAQMD's public notice of intent to issue Permits to Construct and to revise the Title V permit for the facility (SCAQMD 2016a). Public comment period is expected to conclude on July 9, 2016.

ENVIRONMENTAL IMPACT ANALYSIS

SETTING

Meteorological Conditions

The meteorological conditions would be the same as previously analyzed for the licensed HBEP. The climate of the South Coast Air Basin (basin) is strongly influenced by local terrain and geography. The basin is a coastal plain with connecting broad valleys and low hills, bounded by the Pacific Ocean on the west, and relatively high mountains forming the north, south, and east perimeters. The climate is mild, tempered by cool sea breezes and is dominated by the semi-permanent high pressure of the eastern Pacific.

Across the 6,600-square-mile basin, there is little variation in the annual average temperature of 62°F. However, the eastern portion of the basin (generally described as the Inland Empire area), experiences greater variability in annual minimum and maximum temperatures as this area is farther from the coast and the moderating effect on climate from the ocean is weaker. All portions of the basin have recorded temperatures well above 100°F. January is usually the coldest month, while the months of July and August are usually the hottest. The majority of the rainfall in the basin falls during the period from November through April. Annual rainfall values range from approximately 9 inches per year in Riverside, to 14 inches per year in downtown Los Angeles. Monthly and annual rainfall totals can vary considerably from year to year. Cloud cover, in the form of fog or low stratus, is often caused by persistent low inversions and the cool coastal ocean water. Downtown Los Angeles experiences sunshine approximately 73 percent of the time during daylight hours, while the inland areas experience a slightly higher amount of sunshine, and the coastal areas a slightly lower value (WRCC 2016).

Wind and sunlight affect dispersion of onsite air pollutant emissions and the transport of air pollution to and from the site. Wind roses and wind frequency distribution data collected at John Wayne Airport station were provided by the project owner (HBEP 2015a). The most predominant annual wind direction at this monitoring site is from the southwest. The annual calm wind is about 2.8 percent and the annual average speed is 2.44 meters/second (m/s).

Along with the wind flow, atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability reflects the amount of atmospheric turbulence and mixing. In general, the less stable an atmosphere, the greater the turbulence, which results in more mixing and better dispersion. The mixing height, measured from the ground upward, is the height of the atmospheric layer in which convection and mechanical turbulence promote mixing. Good ventilation results from a high mixing height and at least moderate wind speeds within the mixing layer. In general, mixing is more limited at night and in the winter in the basin when there is a higher potential for lower level inversion layers being present along with low speed surface winds.

Ambient Air Quality Standards

The United States Environmental Protection Agency (U.S. EPA) and the California Air Resource Board (ARB) have both established allowable maximum ambient concentrations of criteria air pollutants. These are based upon public health impacts and are called ambient air quality standards. The California Ambient Air Quality Standards (CAAQS), established by ARB, are typically lower (more stringent) than the federally established NAAQS.

Primary ambient air quality standards are designed to protect people who are most susceptible to respiratory distress such as asthmatics, the elderly, very young children, people already weakened by other disease or illness, and people engaged in strenuous work or exercise. Secondary ambient air quality standards are also set to protect public welfare, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

Current state and federal ambient air quality standards are listed in **Air Quality Table 2**. The averaging time for the various ambient air quality standards (the duration over which all measurements taken are averaged) ranges from one hour to one year. The standards are read as a concentration, in parts per million (ppm), parts per billion (ppb), or as a weighted mass of material per unit volume of air, in milligrams (mg or 10^{-3} g) or micrograms (µg or 10^{-6} g) of pollutant in a cubic meter (m^3) of ambient air, drawn over the applicable averaging period.

The only standard that has changed since the HBEP was approved is the NAAQS for ground-level ozone. On October 1, 2015, U.S. EPA strengthened the NAAQS for ground-level ozone from 0.075 parts per million (ppm) to 0.070 ppm, which became effective on December 28, 2015.

Existing Ambient Air Quality

The U.S. EPA, ARB, and the local air district classify an area as attainment, unclassified, or nonattainment, depending on whether or not the monitored ambient air quality data show compliance, insufficient data is available, or non-compliance with the ambient air quality standards, respectively. The Amended HBEP project site would be located within the South Coast Air Basin (SCAB) and within the SCAQMD. The federal and state attainment status of criteria pollutants in the SCAB are summarized in **Air Quality Table 3**. After the Final Staff Assessment (FSA) of the licensed HBEP (CEC 2014d) was published, ARB re-designated the SCAB from nonattainment to attainment for the state NO_2 standards, which became effective on July 1, 2014.

As with the licensed HBEP, meteorological data from the John Wayne Airport station was used for air quality modeling to determine the impacts of the Amended HBEP. Although the operating monitoring station closest to the proposed site is North Coastal Orange County station (also called the Costa Mesa station), the data from the John Wayne Airport station is more appropriate because of the following factors: 1) surface characteristics at John Wayne Airport are more similar to the project site, 2) John Wayne Airport data is more current, 3) John Wayne Airport has fewer missing data points and 4) the Costa Mesa data provides inconsistent results because the calm winds percentage varies from 0 percent to 38 percent depending on data processing methods. As with the licensed HBEP, background concentrations of O_3, NO_2, SO_2, and CO were determined using North Coastal Orange County monitoring station data, located about 3.5 miles northeast from the project site – PM10 and PM2.5 are not currently measured at this site. Ambient concentrations of PM10 and PM2.5 are collected from North Long Beach station, approximately 17 miles to the northwest of the project site.

Air Quality Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.070 ppm (137 μg/m^3)[a]	0.070 ppm (137 μg/m^3)
	1 Hour	—	0.09 ppm (180 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual	53 ppb (100 μg/m^3)	0.030 ppm (57 μg/m^3)
	1 Hour	100 ppb (188 μg/m^3)[b]	0.18 ppm (339 μg/m^3)
Sulfur Dioxide (SO_2)	24 Hour	—	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1300 μg/m^3)	—
	1 Hour	75 ppb (196 μg/m^3)[c]	0.25 ppm (655 μg/m^3)
Respirable Particulate Matter (PM10)	Annual	—	20 μg/m^3
	24 Hour	150 μg/m^3	50 μg/m^3
Fine Particulate Matter (PM2.5)	Annual	12.0 μg/m^3	12 μg/m^3
	24 Hour	35 μg/m^3 [b]	—
Sulfates (SO_4)	24 Hour	—	25 μg/m^3

Pollutant	Averaging Time	Federal Standard	California Standard
Lead	30 Day Average	—	1.5 μg/m^3
	Rolling 3-Month Average	0.15 μg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.01 ppm (26 μg/m^3)
Visibility Reducing Particulates	8 Hour	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.

Source: ARB 2016a, U.S. EPA 2016a
Note: [a] Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years. Final rule signed October 1, 2015, and effective December 28, 2015.
[b] 98th percentile of daily maximum value, averaged over 3 years
[c] 99th percentile of daily maximum value, averaged over 3 years

Air Quality Table 3
Attainment Status of South Coast Air Basin (SCAB)

Pollutants	Attainment Status	
	Federal Classification	**State Classification**
Ozone (1-hr)	No Federal Standard	**Nonattainment**
Ozone (8-hr)	**Nonattainment**	**Nonattainment**
CO	Attainment	Attainment
NO_2	Unclassified/Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Attainment	**Nonattainment**
PM2.5	**Nonattainment**	**Nonattainment**

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

Nonattainment Criteria Pollutants

The Final Commission Decision of the licensed HBEP project (CEC 2014bb) included ambient monitoring data from 2007 to 2012. For this amendment analysis, staff has updated the ambient monitoring data tables since more recent data became available. **Air Quality Table 4** summarizes the existing ambient monitoring data for nonattainment criteria pollutants (ozone and particulate matter) collected from 2009 to 2014 by ARB and SCAQMD from monitoring stations near the project site. Data in this table that are marked in **bold** indicate that the most-stringent current standard was exceeded during that period. Note that an exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.

Air Quality Table 4

Nonattainment Criteria Pollutants Concentrations, 2009-2014 (ppm or $\mu g/m^3$)

Pollutant	Averaging Time	2009	2010	2011	2012	2013	2014
Ozone (ppm)	1 hour	0.087	**0.097**	**0.093**	**0.09**	**0.095**	**0.096**
Ozone (ppm)	8 hour	**0.075**	**0.076**	**0.077**	**0.076**	**0.083**	**0.079**
PM10 ($\mu g/m^3$)	24 hour	**62**	44	43	45	37	NA
PM10 ($\mu g/m^3$)	Annual	**30.5**	**22**	**24.2**	**23.3**	**23.2**	NA
PM2.5 ($\mu g/m^3$)	24 hour	34.2	28.3	27.8	26.4	26.1	NA
PM2.5 ($\mu g/m^3$)	Annual	**13**	10.5	11	10.4	11.34	NA

Source: ARB 2016c, SCAQMD 2016, U.S. EPA 2016c.

NO_2 was listed as nonattainment pollutant in the Final Commission Decision for the licensed HBEP. Since the SCAB is now designated as unclassified/attainment for federal and state NO_2 standards, staff has moved the NO_2 data and corresponding discussions to the Attainment Criteria Pollutants section.

Ozone

Ozone is not directly emitted from stationary or mobile sources. It is a secondary pollutant formed through complex chemical reactions between nitrogen oxides (NOx) and volatile organic compounds (VOC). Ozone formation is highest in the summer and fall when abundant sunshine and high temperatures trigger the necessary photochemical reactions, and lowest in the winter. The days with the highest ozone concentrations in this region commonly occur between May and October. The SCAQMD is classified as a nonattainment area with respect to both state and national ambient air quality standards for ozone.

Respirable Particulate Matter (PM10)

PM10 is a mixture of small solid particles and liquid droplets with a size less than or equal to 10 microns diameter. PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx and VOC from turbines, and ammonia from NOx control equipment, given the right meteorological conditions, can form particulate matter in the form of nitrates (NO_3), sulfates (SO_4), and organic particles. These pollutants are known as secondary particulates, because they are not directly emitted but are formed through complex chemical reactions in the atmosphere.

PM nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. The nitrate ion concentrations during the wintertime are a significant portion of the total PM10, and an even higher contributor to particulate matter of less than 2.5 microns (PM2.5), described more fully below. The nitrate ion is only a portion of the PM nitrate, which can be in the form of ammonium nitrate (ammonium plus nitrate ions) or sodium nitrate.

As shown in **Air Quality Table 4**, the federal 24-hour PM10 standard of 150 μg/m^3 was not exceeded at the stations near the project site from 2009 through 2014. However, the CAAQS 24-hour PM10 standard of 50 μg/m^3 was exceeded in 2009. The maximum 24-hour concentration recorded during the analysis period was 62 μg/m^3 in 2009. The maximum annual concentration was 30.5 μg/m^3 in 2009. The SCAB is characterized as attainment for federal PM10 standard but nonattainment for state PM10 standard.

Fine Particulate Matter (PM2.5)

PM2.5 refers to particles and droplets with a diameter less than or equal to 2.5 microns. PM 2.5 is believed to pose a greater health risk than PM10 because it can lodge deeply into the lungs due to the small size. PM2.5 includes nitrates, sulfates, organic carbon and elemental carbon, which mainly result from combustion and atmospheric reactions. Almost all combustion-related particles, including those from wood smoke and cooking, are smaller than 2.5 microns. Nitrate and sulfate particles are formed through complex chemical reactions in the atmosphere. Particulate nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. The nitrate ion concentrations during the winter make up a large portion of the total PM2.5.

Air Quality Table 4 summarizes the ambient PM2.5 data collected from the North Long Beach station. The national 24-hour average NAAQS is met if the 3-year average of the 98th percentile concentration is 35 μg/m^3 or lower. This threshold was not exceeded from 2009 through 2014. The annual arithmetic mean of 13 μg/m^3 in 2009 exceeded the state and federal standard of 12 μg/m^3. For purpose of state and federal air quality planning and permitting, the SCAB is nonattainment with both federal and state PM2.5 standard.

<u>Attainment Criteria Pollutants</u>

Nitrogen Dioxide (NO_2)

Nitrogen oxides (NOx) include nitric oxide (NO) and nitrogen dioxide (NO_2). Approximately 75 to 90 percent of the NOx emitted from combustion sources is NO. NO is oxidized in the atmosphere to NO_2 by oxygen and ozone. High ambient concentrations of NO_2 usually occur during the fall when atmospheric conditions tend to trap ground-level emissions but lack significant photochemical activity due to less sunlight. In the summer, the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions (atmospheric unstable conditions) generally disperse pollutants and also engage NO in reactions with VOCs to form ozone. The formation of NO_2 in the presence of ozone is according to the following reaction:

$$NO + O_3 \rightarrow NO_2 + O_2$$

Urban areas typically have high daytime ozone concentrations that drop substantially at night as the above reaction takes place, and ozone scavenges the available NO. If ozone is unavailable to oxidize the NO, less NO_2 will form because the reaction is “ozone-limited.” This reaction explains why, in urban areas, ground-level ozone concentrations drop at night, while aloft and in downwind rural areas (without sources of fresh NO emissions), nighttime ozone concentrations can remain relatively high.

The U.S. EPA implemented a new 1-hour NO_2 standard of 0.1 ppm, which became effective on April 12, 2010. The new standard is expressed as a 3-year average of the 98^{th} percentile of the daily maximum 1-hour concentration (i.e., the 8^{th} highest of daily highest 1-hour concentrations). **Air Quality Table 5** shows the maximum 1-hour, federal 1-hour, and annual NO_2 concentrations at the Costa Mesa station. The SCAQMD is currently designated as unclassified for federal NO_2 standards and attainment for the state NO_2 standards (effective since July 1, 2014).

Carbon Monoxide

Carbon monoxide (CO) is a product of incomplete combustion due to the insufficiency of oxygen content at the point of combustion. Mobile sources are the main sources of CO emissions. Ambient concentrations of CO are highly dependent on motor vehicle activity. CO is a local pollutant, with high concentrations usually found near the emission sources. The highest CO concentrations occur during rush hour traffic in the mornings and afternoons. Ambient CO concentrations attain the air quality standards due to two statewide programs: 1) the 1992 wintertime oxygenated gasoline program, and 2) Phase I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to reduced CO emissions. **Air Quality Table 5** shows the maximum 1-hour and 8-hour CO concentrations at the Costa Mesa/North Coastal Orange County station. These values are well below respective ambient air quality standards.

Air Quality Table 5
Attainment Criteria Pollutants Concentrations, 2009-2014 (ppm)

Pollutant	Averaging Time	2009	2010	2011	2012	2013	2014
NO_2	1 hour	0.07	0.07	0.06	0.074	0.0757	0.0606
NO_2	Federal 1 hour	0.057	0.056	0.053	0.05	0.0532	0.0547
NO_2	Annual	0.013	0.011	0.01	0.01	0.0116	0.011
CO	1 hour	3	2	3	2.1	2.4	3
CO	8 hours	2.2	2.1	2.2	1.7	2	1.9
SO_2	State 1 hour	0.01	0.01	0.008	0.006	0.0042	0.0088
SO_2	Federal 1 hour (99^{th} percentile)	0.004	0.002	0.005	0.002	0.0033	0.004
SO_2	24 hour	0.004	0.002	0.001	0.001	0.0012	0.0014

Source: ARB 2016c, SCAQMD 2016, U.S. EPA 2016c.

Sulfur Dioxide

Sulfur dioxide is typically emitted as a result of the combustion of fuels containing sulfur. This proposed project would use natural gas, which contains very little sulfur and consequently has very low SO_2 emissions when burned. By contrast, fuels with high sulfur content, such as coal, emit very large amounts of SO_2 when burned. Sources of SO_2 emissions come from every economic sector and include a wide variety of fuels in gaseous, liquid and solid forms. The whole state is designated attainment for all state and federal SO_2 ambient air quality standards. See **Air Quality Table 5** for maximum 1-hour, federal 1-hour, and 24-hour SO_2 concentrations at the Costa Mesa station.

Summary of Existing Ambient Air Quality

In summary, staff recommends using the background ambient air quality concentrations in **Air Quality Table 6** as the baseline for the modeling and impacts analysis. The highest criteria pollutant concentrations from the last three years of available data collected at the monitoring stations are used to determine the recommended background values. Concentrations in excess of their ambient air quality standard are shown in **bold**.

The pollutant modeling analysis was limited to the pollutants listed in **Air Quality Table 6**. Therefore recommended background concentrations were not determined for the other criteria pollutants (ozone, lead, visibility, etc.).

Compared to the staff recommended background concentrations shown in the Final Commission Decision of the licensed HBEP (CEC 2014bb), the annual PM2.5, state 1-hour NO_2, and annual NO_2 background concentrations have increased a little bit but are all below the corresponding standards, with the annual PM2.5 background concentrations getting closer to the limiting standard. Background concentrations for other pollutants and other averaging periods have either decreased or stayed the same as those shown in the Final Commission Decision of the licensed HBEP (CEC 2014bb).

Air Quality Table 6
Staff-Recommended Background Concentrations ($\mu g/m^3$)

Pollutant	Averaging Time	Background	Limiting Standard	Percent of Standard
PM10	24 hour	45	50	90
	Annual	**24.2**	20	**121**
PM2.5	24 hour	27.8	35	79
	Annual	11.34	12	95
CO	1 hour	3,450	23,000	15
	8 hour	2,222	10,000	22
NO_2	State 1 hour	142.6	339	42
	Federal 1 hour	102.8	188	55
	Annual	22.0	57	39
SO_2	1 hour	23.1	655	4
	Federal 1 hour	10.5	196	5
	24 hour	3.7	105	4

Source: ARB 2016c, SCAQMD 2016, U.S. EPA 2016c and independent staff analysis.
Note: An exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.

PROJECT DESCRIPTION AND PROPOSED EMISSIONS

The Amended HBEP would be a natural-gas-fired, combined-cycle and simple-cycle, air-cooled electrical generating facility. The combined-cycle power block would consist of a two-on-one combined-cycle unit with two GE Frame 7FA.05 gas turbines, two unfired HRSGs, one steam turbine generator, one air-cooled condenser, one natural-gas-fired auxiliary boiler, and related ancillary equipment. The simple-cycle power block would include two GE LMS-100PB simple-cycle turbines and their separate ancillary equipment. The existing two emergency diesel fire water pumps installed at the Huntington Beach Generating Station will remain in service for the Amended HBEP under SCAQMD permits.

Separate emissions estimates for the Amended HBEP during the construction/ demolition, initial commissioning, and operation are each described next.

PROPOSED CONSTRUCTION EMISSIONS

Construction of the Amended HBEP is expected to take about 120 months, which includes demolition of existing structures and construction of the new electrical generating components. Construction of the licensed HBEP was expected to take less time (about 90 months), which was based on estimation of more overlaps of demolition, construction, commissioning, and operation activities throughout the construction period. Construction of the Amended HBEP would require removal of the existing HBGS Unit 5 (for the combined-cycle power block) and Units 3 and 4 (for the simple-cycle power block). Upon the commercial operation of the Amended HBEP simple-cycle power block, existing HBGS Units 1 and 2 would be decommissioned and demolished to their turbine deck.

As with the licensed HBEP, demolition of existing Units 3 and 4 is not part of the Amended HBEP project definition because it is part of the Huntington Beach Modernization Project and demolition of Units 3 and 4 were approved as part of that project. However, demolition of these two units is included as part of the cumulative impact assessment for the Amended HBEP. Demolition of existing Unit 5 includes removal of the non-operational Unit 5 peaker and two former fuel oil tanks. Removal/demolition of existing HBGS Units 1 and 2 is not specifically required for Amended HBEP but would be completed voluntarily by the project owner. Construction of the combined-cycle power block and the simple-cycle power block is expected to take approximately 35 and 20 months respectively (HBEP 2015h).

Amended HBEP may require the use of an additional 20 acres beyond the 1.9 acres identified in the Final Commission Decision for the licensed HBEP at the former Plains All American Tank Farm site located adjacent to the HBEP site for construction laydown and construction worker parking. Therefore, staff’s analysis includes a total of 22 acres of the former Plains All American Tank Farm site for construction laydown and construction worker parking.

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 bulldozing during construction of the Amended HBEP; and 3) fugitive dust from demolition activities such as the removal of the stacks and loading waste haul trucks with the generated debris. Construction emissions are estimated based on the work schedule of 10 hours per day, 23 days per month (HBEP 2015a).

Estimates for the highest daily, monthly, and total annual emissions (onsite and offsite combined) over the 120-month construction period are shown in **Air Quality Table 7**. The maximum daily construction/demolition emissions would occur during month 30 for VOC, CO, NOx, and SO_2, and during month 32 for PM10 and PM2.5. The maximum annual construction/demolition emissions would occur between months 26 and 37 for VOC, CO, SO_2, PM10, and PM2.5, and between months 25 and 36 for NOx. Construction of the combined-cycle power block would occur during months 18 through 52 and would contribute to the maximum daily, monthly, and annual construction emissions.

Air Quality Table 7 also shows maximum construction emissions approved for the licensed HBEP for comparison purposes. Except for the VOC emissions, the maximum construction emissions (onsite and offsite combined) estimated for the Amended HBEP would be higher than those estimated for the licensed HBEP because of higher offsite emissions estimated from offsite delivery and material hauling trucks.

Proposed Initial Commissioning Emissions

New electrical generation facilities must go through initial commissioning phases before becoming commercially available to generate electricity. The commissioning period begins when the turbines are prepared for first fire and ends upon successful completion of initial performance testing. During this period, initial firing causes greater NOx and CO emissions than those that occur during normal operations because of the need to tune the combustor, conduct numerous startups and shutdowns, operate under low loads, and conduct testing before emission control systems are functioning or fine-tuned for optimum performance. Gas turbine suppliers can have different commissioning period requirements.

Air Quality Table 7
Estimated Maximum Construction Emissions

Construction Activity	NOx	VOC	PM10	PM2.5	CO	SOx
Amended HBEP						
Maximum Daily Construction Emissions (lbs/day)	189.0	8.8	29.1	10.0	116.0	0.78
Maximum Monthly Construction Emissions (lbs/month)	4,345.9	202.3	670.3	229.9	2,667.2	18.0
Peak Annual Construction Emissions (tons/year)	20.1	0.98	3.3	1.1	14.9	0.087
Licensed HBEP						
Maximum Daily Construction Emissions (lbs/day)	79.5	12.7	17.0	7.54	88.1	0.20
Maximum Monthly Construction Emissions (lbs/month)	1,829	291	396	173.32	2,026	4.56
Peak Annual Construction Emissions (tons/year)	8.6	1.3	1.88	0.72	9.1	0.02

Source: CEC 2014bb, HBEP 2015a, HBEP 2015h, and independent staff analysis.
Note: Maximum emissions include contributions from onsite and offsite construction equipment and vehicles. The PM10 and PM2.5 emissions include exhaust and fugitive dust emissions.

The project owner expects the total duration of the combined-cycle power block and simple-cycle power block commissioning periods to be up to 1,992 hours (996 hours per turbine) and 560 hours (280 hours per turbine) respectively. The project owner expects the duration of the auxiliary boiler commissioning would take 5 days and would require up to 6 fired hours per day. **Air Quality Table 8** presents the project owner's anticipated maximum commissioning emissions of criteria pollutants for the turbines and the auxiliary boiler. Maximum hourly emissions for NOx, CO and VOC would occur in combustion turbine generator (CTG) testing phases (full speed, no load). Although NOx, CO and VOC emissions exceed operating condition emissions during commissioning, emission rates for PM and SOx during initial commissioning are not expected to be higher than normal operating emissions. This is because PM and SOx emissions are proportional to fuel use. The project owner expects the auxiliary boiler commissioning emissions to be the same as the auxiliary boiler cold startup emissions (HBEP 2016n).

Air Quality Table 8 also presents the estimated commissioning emissions of the licensed HBEP for comparison purposes. The maximum hourly NOx and SOx emissions during commissioning of each GE Frame 7FA.05 turbine would be higher than those estimated for the commissioning of each Mitsubishi Heavy Industries 501DA turbine of the licensed HBEP. The maximum hourly emissions of VOC, PM10/PM2.5, and CO during commissioning of each GE Frame 7FA.05 turbine would be lower than those estimated for the commissioning of each Mitsubishi Heavy Industries 501DA turbine of the licensed HBEP. The emissions of the simple-cycle turbines during commissioning would be less than those for the Mitsubishi Heavy Industries 501DA turbines of the licensed HBEP.

Air Quality Table 8
Maximum Initial Commissioning Emissions

Commissioning Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Amended HBEP					
Each GE Frame 7FA.05 turbine (lb/hr)	130	270	8.5	1,900	4.86
Total commissioning emissions for the two GE Frame 7FA.05 turbines (tons)	27.6	14.7	8.5	101.3	4.8
Each GE LMS-100PB turbine (lb/hr)	40.1	5.1	6.24	244.0	1.64
Total commissioning emissions for the two GE LMS-100PB turbines (tons)	5.7	0.8	1.7	25.4	0.46
Auxiliary boiler (lb/hr)	1.49	0.37	0.51	1.53	0.14
Total commissioning emissions for the auxiliary boiler (tons)	0.02	0.01	0.007	0.02	0.002
Licensed HBEP					
Each CTG (lb/hr)	109.7	383.8	9.5	3,169	2.78
Each CTG (tons/commissioning period)	4.1	7	1.5	56	0.53

Source: CEC 2014d, HBEP 2016n, SCAQMD 2016b, and independent staff analysis

Proposed Operation Emissions

Air Quality Tables 9 through **11** summarize the maximum (worst-case) criteria pollutant hourly, daily and annual emissions associated with Amended HBEP's normal and routine operation. Emissions for the combustion turbines and the auxiliary boiler are based upon:

- NOx emissions would be controlled to 2.0 parts per million by volume, dry basis (ppmvd), corrected to 15 percent oxygen for each GE 7FA.05 turbine, 2.5 ppmvd for each GE LMS-100PB turbine, and 5.0 ppmvd corrected to 3 percent oxygen for the auxiliary boiler;
- VOC emissions would be controlled to 2.0 ppmvd for the turbines with the use of good combustion practices and an oxidation catalyst;
- CO emissions would be controlled to 2.0 ppmvd corrected to 15 percent oxygen for each GE 7FA.05 turbine, 4.0 ppmvd corrected to 15 percent oxygen for each GE LMS-100PB turbine, and 50 ppmvd corrected to 3 percent oxygen for the auxiliary boiler;
- PM10/PM2.5 emissions would be limited to 8.5 lbs/hr for each GE 7FA.05 turbine and 6.24 lbs/hr for each GE LMS-100PB turbine;
- SOx emissions would be based on sulfur content of 0.75 gr/100 cf for short term (hourly, daily, monthly) emissions and 0.25 gr/100 cf for long term (annual) emissions;

- Maximum annual operating emissions from each GE 7FA.05 turbine would be based on 6,100 hours of full load operation, plus 80 cold startups, 88 warm startups, 332 hot startups, and 500 shutdowns; and
- Maximum annual operating emissions from each GE LMS-100PB turbine would be based on 1,750 hours of full load operation, plus 350 startups, and 350 shutdowns.

Air Quality Tables 9 lists the maximum hourly emissions from the proposed turbines and auxiliary boiler. Emissions for NOx, CO, and VOC during startup and shutdown events would normally have higher emissions than during normal operation. The worst case hourly NOx, CO, and VOC emissions from the GE 7FA.05 turbines would be during cold startups. **Air Quality Tables 9** also lists the maximum hourly emissions from each Mitsubishi Heavy Industries 501DA turbine of the licensed HBEP. The worst case hourly emissions of each GE 7FA.05 turbine would be higher than those approved for each Mitsubishi Heavy Industries 501DA turbine of the licensed HBEP, except for PM emissions. The PM BACT level has reduced to 8.5 lbs/hr for the proposed combined-cycle turbines, compared to 9.5 lbs/hr for the approved combined-cycle turbines of the licensed HBEP.

For the GE LMS-100PB turbines, there could be an hour when both a startup and shutdown occur. For such hours, there would be 30 minutes of elevated emissions due to the startup, 17 minutes of normal operation, and 13 minutes of elevated emissions due to 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. The worst case hourly emissions of each GE LMS-100PB turbine would be lower than those approved for each Mitsubishi Heavy Industries 501DA turbine of the licensed HBEP.

The worst case hourly NOx and VOC emissions of the auxiliary boiler would be during cold startups. The worst case hourly CO, PM10/PM2.5 and SOx emissions of the auxiliary boiler would be during full-load operation.

Air Quality Table 9
Maximum Hourly Emissions Rates during Routine Operation
(pounds per hour [lbs/hr])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Amended HBEP					
Each GE 7FA.05	61	36	8.5	325	4.6
Each GE LMS-100PB	22	6.5	6.24	45.7	1.8
Auxiliary boiler	1.49	0.37	0.51	2.83	0.14
Oil Water Separators [a]	--	0.022	--	--	--
Licensed HBEP					
Each CTG	25.5	31.8	9.5	115.3	2.78

Source: CEC 2014d, HBEP 2016n, SCAQMD 2016b, and independent staff analysis
Note: [a] Staff calculated the hourly VOC emissions of the oil water separators based on the annual emissions from PDOC (SCAQMD 2016b) averaged over 8,760 hours per year.

Air Quality Table 10 lists maximum daily emissions of the Amended HBEP. The daily emissions are calculated as monthly emissions divided by 30. The monthly emissions of each GE 7FA.05 turbine are based on the assumption of 31 days of operation including 15 cold startups, 12 warm startups, 35 hot startups, and 62 shutdowns per month (startups and shutdowns are defined and limited in **AQ-22** and **AQ-23**). The monthly emissions of each GE LMS-100PB turbine are based on the assumption of 31 days of operation including 62 startups and 62 shutdowns per month (startups and shutdowns are defined and limited in **AQ-25** and **AQ-26**). The monthly emissions of the auxiliary boiler are based on the assumption of 2 cold startups, 4 warm startups, 4 hot startups (startups and shutdowns are defined and limited in **AQ-28**), and 15,793 MMBtu of fuel consumption for normal operations per month.

Air Quality Table 10 also lists the maximum daily facility total emissions for the licensed HBEP for comparison purposes. The maximum daily facility total emissions of the Amended HBEP would be lower than those approved for the licensed HBEP.

Air Quality Table 10
Maximum Daily Emissions during Routine Operation (pounds per day [lb/day])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Amended HBEP					
Total of two GE 7FA.05 turbines	911	507	422	1,763	228
Total of two GE LMS-100PB turbines	464	131	310	548[a]	89.2
Auxiliary boiler	3.8	2.9	4.0	21.7	1.1
Oil Water Separators	--	0.54	--	--	--
Facility Total	1,378.8	642.3	735.1	2,332.5	318.5
Licensed HEBP					
Maximum Facility Total (Six Turbines) of Three Scenarios	2,035	1,744	798	3,208	321

Source: CEC 2014d, HBEP 2016n, SCAQMD 2016b, and independent staff analysis
Note: [a] Staff corrected the SCAQMD's CO emissions calculations for the GE LMS-100PB turbines based on the project owner provided emission rate of 28.09 lbs/event during shutdowns, instead of the 28.9 lbs/event used by the SCAQMD. But the difference is relatively insignificant (less than 1 percent).

Air Quality Table 11 lists maximum potential annual emissions from the Amended HBEP project, based on project owner and SCAQMD calculations reviewed by staff. The operating profile of each GE 7FA.05 turbine includes 6,100 hours of full load operation, 80 cold startups, 88 warm startups, 332 hot startups, and 500 shutdowns per year (startups and shutdowns are defined and limited in **AQ-22** and **AQ-23**). The operating profile of each GE LMS-100PB turbine includes 1,750 hours of full load operation, 350 startups, and 350 shutdowns per year (startups and shutdowns are defined and limited in **AQ-25** and **AQ-26**). The maximum annual emissions of the auxiliary boiler are based on 24 cold startups, 48 warm startups, 48 hot startups (startups and shutdowns are defined and limited in **AQ-28**), and 182,703 MMBtu of fuel consumption for normal operations per year. **Air Quality Table 11** shows that the facility total annual emissions of the Amended HBEP would be lower than those approved for the licensed HBEP.

AIR Quality Table 11
Maximum Annual Emissions during Routine Operation
(tons per year [tpy])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Amended HBEP					
Total of two GE 7FA.05 turbines	120	64.8	56.4	212	10.0
Total of two GE LMS-100PB turbines	21.3	6.1	12.5	29.0[a]	1.2
Auxiliary boiler	0.7	0.5	0.7	3.8	0.2
Oil Water Separators	--	0.10	--	--	--
Facility Total	141.4	71.4	69.6	245.1	11.4
Licensed HBEP					
Facility Total (Six Turbines)	251.0	167.7	99.3	282.8	15.3

Source: CEC 2014d, HBEP 2016n, SCAQMD 2016b, and independent staff analysis
Note: [a] Staff corrected the SCAQMD's CO emissions calculations for the GE LMS-100PB turbines based on the project owner provided emission rate of 28.09 lbs/event during shutdowns, instead of the 28.9 lbs/event used by the SCAQMD. But the difference is relatively insignificant (less than 1 percent).

Ammonia Emissions

Ammonia (NH_3) is injected into the flue gas stream as part of the selective catalytic reduction (SCR) system that controls NOx emissions. In the presence of the catalyst, the ammonia and NOx react to form harmless elemental nitrogen and water vapor. However, not all of the ammonia reacts with the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered from the stacks. These ammonia emissions are known as ammonia slip.

As with the licensed HBEP, SCAQMD requires a maximum ammonia slip rate of 5 ppmvd at 15 percent oxygen for the proposed turbines and 5 ppmvd at 3 percent oxygen for the auxiliary boiler (SCAQMD 2016b). The project owner expects the ammonia slip rate from the SCRs of the GE 7FA.05 turbines, the GE LMS-100PB turbines, and the auxiliary boiler would not exceed the 5 ppmvd limit. Energy Commission staff notes that control systems can be operated and maintained to routinely achieve less than 5 ppmvd, as established in the Guidance for Power Plant Siting (ARB 1999). Staff recommends that the Energy Commission impose a 5 ppmvd emissions limit in condition of certification **AQ-15**.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff characterizes air quality impacts as follows: all project emissions of nonattainment criteria pollutants and their precursors (NOx, VOC, PM10, PM2.5, and SOx) are considered significant and must be mitigated. For relatively short-term construction activities that essentially cease before operation of the power plant, our assessment is qualitative and mitigation consists of controlling construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible. For operating emissions, mitigation includes both BACT and ERCs or other valid emission reductions to mitigate emissions of nonattainment criteria pollutants and their precursors.

The ambient air quality standards used by staff as the basis for characterizing project impacts are health-based standards established by the ARB and U.S. EPA. They are set at levels that contain a margin of safety to adequately protect the health of all people, including those most sensitive to adverse air quality impacts such as the elderly, persons with existing illnesses, children, and infants.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Ambient air quality impacts occur when project emissions cause the ambient concentration of a pollutant to increase. Project-related emissions are the actual mass of emitted pollutants, which are dispersed in the atmosphere before reaching the ground. Analysis begins with quantifying the emissions, and then uses an atmospheric dispersion model to determine the probable change in ground-level concentrations due to the project.

Dispersion models complete the complex, repeated calculations that consider emissions in the context of various ambient meteorological conditions, local terrain, and nearby structures that affect air flow. As with the licensed HBEP, the surface meteorological data used as an input to the dispersion model included five years of meteorological data from John Wayne Airport monitoring station. For the licensed HBEP, staff used meteorological data from 2008 to 2012. For the Amended HBEP, staff used more recent meteorological data from 2010 to 2014.

The project owner conducted the air dispersion modeling based on guidance presented in the *Guideline on Air Quality Models* (U.S. EPA 2005) using the American Meteorological Society/Environmental Protection Agency Regulatory Model known as AERMOD (version 15181). The U.S. EPA designates AERMOD as a “preferred” model for refined modeling in all types of terrain. Except for the combined-cycle commissioning state 1-hour NO_2 impact analysis, the short-term NO_2 impacts (1-hour averaging period) were determined using the Ambient Ratio Method (ARM) with ambient NO_2/NOx ratio of 0.8. The combined-cycle commissioning state 1-hour NO_2 impact analysis is based on Plume Volume Molar Ratio Method (PVMRM) with a default in-stack NO_2/NOx ratio of 0.5 recommended by U.S. EPA.

Project-related modeled concentrations were then added to highest background concentrations to arrive at the total impact of the project even if they are not likely to occur at the same time. The total impact is then compared with the ambient air quality standards for each pollutant to determine whether the project’s emissions would either cause a new violation of the ambient air quality standards or contribute to an existing violation.

The federal 1-hour NO_2 standard is statistically based (i.e., the three year average of the 98th percentile values cannot exceed the applicable limit). In order to demonstrate compliance with the federal 1-hour NO_2 standard following U.S. EPA guidance, the modeled impacts from the project were added to 98^{th} percentile seasonal hour-of-day background NO_2 concentrations obtained from 2010 to 2012. The resulting impacts were then evaluated following U.S. EPA guidance to demonstrate compliance with the statistical standard.

Construction Impacts and Mitigation

This section discusses the project's direct construction ambient air quality impacts assessed by the project owner and, as necessary, independently assessed by Energy Commission staff. The ambient air quality impacts are modeled using AERMOD.

Air Quality Table 12 summarizes the results of the modeling analysis for construction activities for Amended HBEP. The total impact is the sum of the existing background condition plus the maximum impact predicted by the modeling analysis for project activity. The values in **bold** in the Total Impact and Background columns represent the values that either equal or exceed the relevant ambient air quality standard.

Air Quality Table 12
Amended HBEP, Construction-Phase Maximum Impacts (µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	11.1	45	**56.1**	**50**	**112**
	Annual	3.0	**24.2**	**27.2**	**20**	**136**
PM2.5	24 hour [a]	4.3	27.8	32.1	35	92
	Annual	0.8	11.34	**12.2**	**12**	**102**
CO	1 hour	177.4	3,450	3,627.4	23,000	16
	8 hour	140.0	2,222	2,362.0	10,000	24
NO_2 [b]	State 1 hour	27.0	142.6	169.6	339	50
	Federal 1 hour [c]	--	--	121.1	188	64
	Annual	2.05	22	24.0	57	42
SO_2	State 1 hour	0.30	23.1	23.4	655	4
	Federal 1 hour [d]	0.30	10.5	10.8	196	6
	24 hour	0.059	3.7	3.8	105	4

Source: HBEP 2015a, HBEP 2015h, and independent staff analysis
Notes:
[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year average of 98th percentile background concentrations.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.
[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year average of 99th percentile background concentrations.

Air Quality Table 12 shows that PM10 and PM2.5 emissions from construction would cause new exceedances or contribute to existing violations of PM10 and PM2.5 ambient air quality standards except of the 24-hour PM2.5 standard. Therefore, staff believes that particulate matter emissions from construction would cause a significant impact over the construction period. Those emissions can and should be mitigated to a level of insignificance. Significant secondary impacts would also occur for PM10, PM2.5, and ozone because construction-phase emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would also contribute to existing violations of these standards.

As shown in **Air Quality Table 12**, background ambient air quality levels exceeded the most restrictive annual PM10 standard of 20 $\mu g/m^3$ while the 24-hour PM10 and both the annual and 24-hour PM2.5 ambient background levels were close to their respective standards. **Air Quality Table 12** shows that the Amended HBEP would cause the annual PM2.5 standard and the 24-hour PM10 standard to become exceeded and contribute to the existing violation of the annual PM10 standard. The worst-case PM impacts would be due to fugitive emissions. Modeling analysis shows that the worst-case PM impacts would occur on the northeast corner of the fence line. However, the areas of possible exceedance of the 24-hour PM10 standard and annual PM2.5 standard would remain near the project boundary (within 230 ft and 53 ft of the northeast corner of the fence line respectively), which are mostly industrialized areas where the public has no access.

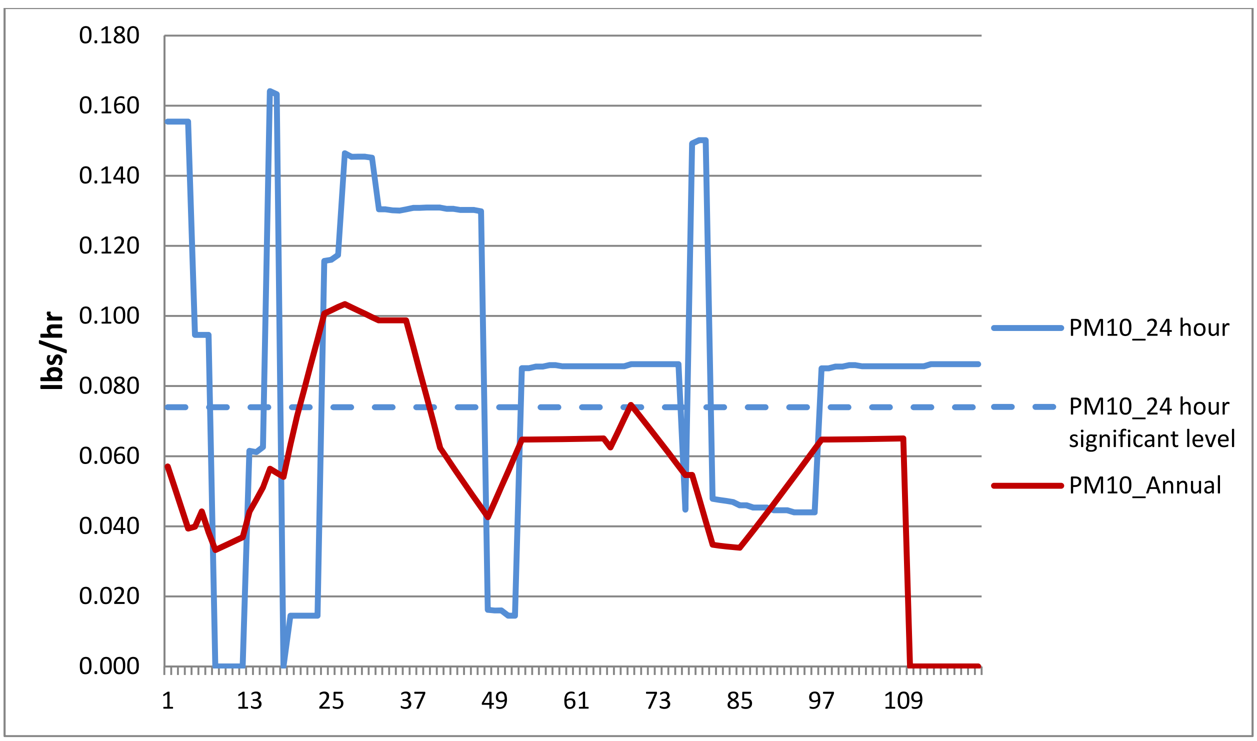
To determine worst-case impacts for both 24-hour and annual averages, the modeling assumes that the maximum emission rates occur during the entire 120-month construction period. However, maximum emissions are only expected to occur over a relatively short portion of the 120-month construction period. In order to estimate typical construction impacts for PM10 and PM2.5, staff calculated the emission rates for each month of construction to show monthly variations, since modeled impacts are proportional to the emission rates. **Air Quality Figure 1a** shows expected PM10 emissions rates for each month of the 120-month construction period. **Air Quality Figure 1b** shows expected PM2.5 emissions rates over the same period. The dotted line in each figure represents the emission rate above which the modeled impacts would exceed the corresponding air quality standard, called the "significant level" in the legend.

Since the annual PM10 background concentration is already above the standard, PM10 emissions from the project would not cause a new exceedance but would contribute to existing violations of this standard. Therefore, no significant level for annual PM10 is identified in that figure. As shown in **Air Quality Figure 1a**, 24-hour PM10 emission rates would be above the significant level during about 70 percent of the entire construction period (84 months out of 120 months). Therefore, PM10 emissions could cause exceedances of the 24-hour standard and thus create significant impacts. Staff proposes condition of certification **AQ-SC6** to mitigate these impacts to the extent possible.

However, emission rate above the significant level for 84 months (70 percent of the construction period) does not mean the 24-hour standard would be exceeded for the whole 84 months. Staff's impacts analysis is extremely conservative, since the maximum impacts are evaluated under a combination of worst-case emission rates, the most extreme meteorological conditions, and worst-case background values, which are unlikely to all occur simultaneously.

For the licensed HBEP, 24-hour PM10 emission rates would be above the significant level during 54 months out of the 90-month construction period (based on staff's analysis of emissions for the licensed HBEP), instead of ¾ of the construction period shown in the FSA for the licensed HBEP (CEC 2014d). The Amended HBEP could cause exceedances of the 24-hour PM10 standard for a longer time period than the licensed HBEP. However, the monthly onsite PM emission rates estimated for the Amended HBEP would be lower than those estimated for the licensed HBEP. For the Amended HBEP, the modeling analysis conservatively assumed the worst-case emission rate of 0.164 lb/hr would occur continuously over the whole construction period. The modeling analysis for the licensed HBEP used the worst-case emission rate of 0.52 lb/hr.

Air Quality Figure 1a
Amended HBEP, Worst Case Estimated Construction-Phase PM10 Emission Rates (lbs/hr)

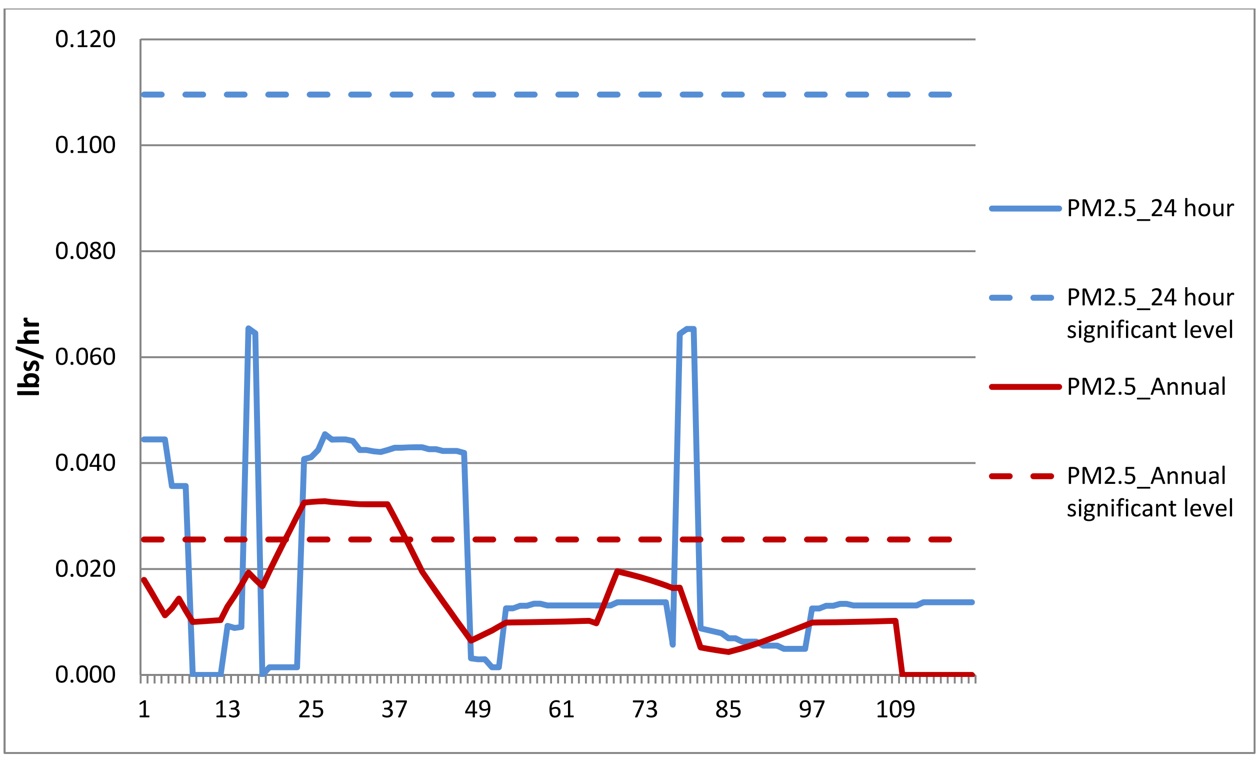


Source: HBEP 2015c, HBEP 2015h, with independent staff analysis.
Note: Worst case emission rates for the 24-hour case are calculated from the worst daily emissions of the month divided by 24 hours/day. Worst case emission rates for the annual case are calculated from the rolling maximum yearly emissions divided by 8,760 hours/year.

The anticipated PM2.5 emission rates are shown in **Air Quality Figure 1b**. Since the total 24-hour PM2.5 impacts would be below the standard, 24-hour PM2.5 emission rates would be below the significant level during the entire construction period. The annual PM2.5 emission rates, when added to relatively high annual background levels at the site, would lead to impacts that would be above the annual standard during months 22 to 49 (**Air Quality Figure 1b** shows annual PM2.5 emission rates above the significant level during months 22 to 38, but the annual emission rate plotted for month 38 represents emissions from month 38 to month 49). PM2.5 emissions would create significant impacts during a total of 28 months identified above. Staff proposes condition of certification **AQ-SC6** to mitigate these impacts to the extent possible.

For the licensed HBEP, the annual PM2.5 emissions rates would be above the significant level for 46 months out of 90-month construction period (accounting for the fact that the annual emissions shown for a certain month represents emissions for a whole year starting from that month), instead of two years shown in the FSA for the licensed HBEP (CEC 2014d). The Amended HBEP would cause exceedances of the annual PM2.5 for a shorter time period than the licensed HBEP. In addition, the annual onsite construction PM2.5 emissions of the Amended HBEP would be lower than those estimated for the licensed HBEP. The worst-case annual PM2.5 emissions converted to hourly emissions would be 0.033 lb/hr for the Amended HBEP (shown in **Air Quality Figure 1b**) and 0.13 lb/hr for the licensed HBEP.

Air Quality Figure 1b
Amended HBEP, Worst Case Estimated Construction-Phase PM2.5 Emission Rates (lbs/hr)



Source: HBEP 2015c, HBEP 2015h, with independent staff analysis.
Note: Worst case emission rates for the 24-hour case are calculated from the worst daily emissions of the month divided by 24 hours/day. Worst case emission rates for the annual case are calculated from the rolling maximum yearly emissions divided by 8,760 hours/year.

As shown in **Air Quality Table 12**, 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 standard. Compliance with the new federal 1-hour NO_2 standard, which is averaged over three years, is also evaluated because the construction is expected to last 120 months. The direct impacts of CO and SO_2 would also not be significant because construction of the Amended HBEP would neither cause nor contribute to an exceedance of these standards.

Construction Mitigation

The project owner proposes the following mitigation measures to reduce the exhaust emissions from the diesel heavy equipment and fugitive dust emissions during the construction phase of the Amended HBEP:

- Watering unpaved roads and disturbed areas
- Limiting onsite vehicle speeds to 10 mph and post the speed limit
- Frequent watering 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 2 weeks
- Using ultra-low sulfur diesel fuel (15 ppm sulfur) in all diesel-fueled equipment
- Use of Tier 4 construction equipment where 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
- Using electric motors for construction equipment to the extent feasible.

Since the modeling results in **Air Quality Table 12** show that PM10 and PM2.5 impacts during the 10-year project construction period would cause exceedances of health-based ambient air quality standards and because staff determined that these impacts would be significant, staff recommends that additional mitigation measures need to be employed to further reduced construction period emissions and potential impacts. For the licensed HBEP, the project owner proposed to sweep roadways in the project vicinity during the construction period with SCAQMD-certified street sweepers. The project owner assumed that only the Pacific Coast Highway (PCH) would be swept and estimated the number of miles where sweeping would be required to mitigate the construction impacts. This mileage was calculated from the amount of emissions reduction required to get PM impacts below the corresponding ambient air quality standard, the control efficiency achieved by sweeping once per month, fugitive dust emission factors for paved roads, and daily vehicle traffic volume on the PCH.

For the licensed HBEP, staff used the above approach to calculate the amount of PM construction emissions reduction required and sweeping miles needed. The emissions reduction required was 8.26 lbs/day for PM10 and 0.79 lbs/day for PM2.5 for the licensed HBEP. The corresponding sweeping miles to achieve these emissions reduction were 3.34 miles for PM10 and 1.28 miles for PM2.5. Therefore the project owner proposed to sweep the PCH 3.5 miles once per month for the duration of the construction period of the licensed HBEP.

For the Amended HBEP, the project owner estimated the PM10 emissions reduction required to be 0.33 tons/year (tpy), which corresponds to 0.81 miles to sweep (HBEP 2015a). However, the project owner's calculation was based on the PM background data measured at Mission Viejo monitoring station. For the licensed HBEP, staff used North Long Beach station as the most representative PM background monitoring station. Staff believes that the North Long Beach monitoring station is more representative of the coastal region that the Amended HBEP would be located. Therefore, for the Amended HBEP, staff performed an independent analysis of the amount of construction emissions reduction required and sweeping miles based on the PM background data measured at North Long Beach monitoring station.

Air Quality Table 12 shows that the construction emissions of the Amended HBEP would cause exceedances of the 24-hour PM10 and annual PM2.5 standards. The amount of PM10 emission reduction required would be based on the estimated maximum daily emission rate resulting in a 24-hour modeled impact that, when combined with the background concentration of 45 $\mu g/m^3$, would be less than the most restrictive 24-hour PM10 standard of 50 $\mu g/m^3$. The amount of PM2.5 emission reduction required would be based on the estimated maximum annual emission rate resulting in an annual modeled impact that, when combined with the background concentration of 11.34 $\mu g/m^3$, would be less than the most restrictive annual PM2.5 standard of 12 $\mu g/m^3$. For example, the 24-hour PM10 impact of the project needs to be less than 5 (=50-45) $\mu g/m^3$ to make sure the total impacts would be less than the 24-hour PM10 standard of 50 $\mu g/m^3$. The worst-case PM10 daily emission rate used in the model is 3.94 lbs/day (0.164 lb/hr) and the worst-case modeled 24-hour PM10 project impact is 11.1 $\mu g/m^3$. Since the worst-case impacts are proportional to the emission rates, the PM10 daily emission rate needs to be reduced to 1.77 lbs/day (=3.94*5/11.1) to get the project impact below 5 $\mu g/m^3$. Therefore, the required emissions reduction for PM10 would be 2.17 lbs/day (=3.94-1.77). Staff uses the same approach to calculate the required construction emissions reduction for PM2.5.

For the Amended HBEP, staff estimated that the required construction emissions reduction would be 2.17 lbs/day for PM10 and 0.17 lbs/day for PM2.5, which would be less than those required for the licensed HBEP. The corresponding sweeping miles to achieve these emission reductions would be 0.98 miles for PM10 and 0.31 miles for PM2.5, which would also be less than those required for the licensed HBEP. The effect of this additional mitigation would be to further reduce project impacts during construction.

Adequacy of Proposed Mitigation

Staff generally concurs with the project owner's proposed mitigation measures, which mirror many of the staff's mitigation recommendations from previous siting cases. However, staff incorporates additional off-road equipment mitigation measures in staff-proposed conditions beyond those proposed by the project owner to implement all current staff recommendations used for other power plant projects.

Staff also agrees that the street sweeping program is an effective way to further mitigate the PM impacts during the extended construction period. To implement this measure, staff proposes that the Energy Commission requires the project owner to develop and provide a street sweeping mitigation plan prior to initiating construction that details the sweeping program and provide the records of the operation of the sweeping program in Monthly Compliance Reports. While time does not allow the details of this plan to be developed at this time, staff believes the plan can rely on performance standards to achieve the needed emission reductions. For example, the plan would lay out how the project owner would obtain agreements from Caltrans or cities so they could safely sweep the PCH or other proposed roads in the vicinity of the project.

Staff Proposed Mitigation

Additional measures recommended by staff would reduce construction-phase impacts by further limiting construction emissions of particulate matter and combustion contaminants. Staff believes that the variable nature of construction activities warrants a qualitative approach to evaluation of the effectiveness of this additional mitigation. Construction emissions and the effectiveness of mitigation varies widely depending on variable levels of activity, the timing of specific work taking place, the specific equipment, soil conditions, weather conditions, and other factors, making precise 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 period emissions. Staff has determined that the use of oxidizing soot filters is a viable emissions control technology for all heavy diesel-powered construction equipment that does not use an ARB-certified low emission diesel engine. In addition, staff proposes that prior to the beginning of construction the project owner should provide an Air Quality Construction Mitigation Plan (AQCMP) that specifically identifies all mitigation measures used to limit air quality impacts during construction.

Staff includes the approved conditions of certification **AQ-SC1** through **AQ-SC5** to implement these requirements. These conditions update the project owner's proposed mitigation measures to be consistent with the conditions of certification adopted in similar prior Energy Commission licensing cases. Compliance with these conditions is expected to mitigate air quality impacts to be less than significant during construction of the Amended HBEP.

For the Amended HBEP, staff proposes to revise condition of certification **AQ-SC6** to require the project owner to reduce the construction emissions by 2.17 lbs/day for PM10 and 0.17 lbs/day for PM2.5, which would be less than those required for the licensed HBEP (8.26 lbs/day for PM10 and 0.79 lbs/day for PM2.5).

However, since the streets to be swept are offsite, staff believes that an off-site offset ratio of 1.2:1, which is typically used by SCAQMD, is more appropriate to be used to determine the total emissions to mitigate. Staff is concerned that the sweeping of the PCH may not be practical due to the high traffic volumes and safety concerns. The local city streets in the project vicinity may be more suitable for the street sweeping program. In addition, if the street sweeping is already routinely performed on the nearby roads, some alternative approaches may be needed, such as using new, or more efficient or lower-emitting street sweepers. The plan should also include, but not limited to, the approval of sweeping from the control agency who is in charge of the roads, the timing of sweeping to avoid other impacts (traffic, noise, etc), the specifics of the type of street sweeper to be used, the traffic control and other logistics necessary during the street sweeping, and water use requirements that may affect this mitigation if a wet sweeper is used, especially in a severe drought. The project owner proposed to use the PCH for street sweeping, and they also listed additional roads that could be used and the associated traffic volumes. These may prove to be a more effective option because they are closer to the construction zone. The project owner should address all issues identified above in a construction period street sweeping PM mitigation plan required by **AQ-SC6**. Staff believes that the significant PM impacts during the construction can be reduced to less than significant by this street sweeping program.

Operation Impacts and Mitigation

The following section discusses ambient air quality impacts that were estimated by the project owner and subsequently evaluated by Energy Commission staff. The project owner performed a number of direct impact modeling analyses for routine operations, including fumigation modeling and modeling for impacts during commissioning activities.

Routine Operation Impacts

A refined dispersion modeling analysis was performed by the project owner 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, and 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 9** to **11**. The predicted maximum concentrations of criteria pollutants are summarized in **Air Quality Table 13**. The values shown in **bold** means they exceed ambient air quality standards.

Air Quality Table 13 shows that with the worst-case modeled 24-hour PM10 impact of 5.1 $\mu g/m^3$ and maximum background at 45 $\mu g/m^3$, the total 24-hour PM10 impact would be 50.1 $\mu g/m^3$, which is a little above the 24-hour PM10 CAAQ of 50 $\mu g/m^3$. However, the worst-case modeling conservatively assumed that each of the GE 7FA.05 turbines would operate at 44 percent load for 24 hours per day (with operation of the GE LMS-100PB turbines and the auxiliary boiler), which is an unlikely scenario. For the PSD impacts analysis, the project owner performed a refined modeling analysis assuming one GE 7FA.05 would operate 24 hours per day at 44 percent load and the other would operate 20 hours per day at 44 percent load and 4 hours per day at 75 percent load.

The maximum modeled 24-hour PM10 impact in this scenario would be 4.97 μg/m^3 from the project owner's refined analysis. Combining the maximum background at 45 μg/m^3, the total 24-hour PM10 impact would be 49.97 μg/m^3, which would be less than the 24-hour PM10 CAAQ of 50 μg/m^3.

In addition, by combining the worst-case modeled impacts with the maximum background, it is conservatively assumed that they would occur at the same time. Staff performed additional independent analysis by pairing 1) worst-case modeled impacts (assuming both GE 7FA.05 turbines at 44 percent load for 24 hours per day for worst-case analysis) with background measured on the same day, and 2) the maximum background with modeled impacts on that day. The worst-case 24-hour PM10 impact of 5.1 μg/m^3 was modeled to occur on June 8, 2012. Staff downloaded the background 24-hour PM10 monitored at North Long Beach station from ARB's website (ARB 2016c). Staff found that the background 24-hour PM10 measured on June 8, 2012 was 33 μg/m^3. With the worst-case modeled 24-hour PM10 impact of 5.1 μg/m^3, the total impact would be 38.1 μg/m^3, which would not exceed the 24-hour PM10 CAAQ of 50 μg/m^3. Therefore, the Amended HBEP would not cause exceedance of the 24-hour PM10 CAAQ of 50 μg/m^3 on the day when the worst-case project impact is modeled. The second highest modeled 24-hour PM10 impact would be less than 5 μg/m^3, thus the Amended HBEP would not cause exceedance of the 24-hour PM10 CAAQ of 50 μg/m^3 if the second highest modeled impact is combined with the maximum background at 45 μg/m^3. The maximum background 24-hour PM10 of 45 μg/m^3 was monitored to occur on January 4, 2012. The highest modeled 24-hour PM10 impacts on that day would be 0.4 μg/m^3. The total 24-hour PM10 impact would be 45.4 μg/m^3 on that day. Therefore, the Amended HBEP would not cause exceedance of the 24-hour PM10 CAAQ of 50 μg/m^3 when the maximum background 24-hour PM10 was monitored.

Air Quality Table 13
Amended HBEP, Routine Operation Maximum Impacts (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	5.1 (4.97) [e]	45	**50.1** (49.97) [e]	**50**	**100.2** (99.9) [e]
	Annual	0.64	**24.2**	**24.8**	**20**	**124**
PM2.5	24 hour [a]	5.1	27.8	32.9	35	94
	Annual	0.64	11.34	11.98	12	99.8
CO	1 hour	630.6	3,450	4,080.6	23,000	18
	8 hour	149	2,222	2,371	10,000	24
NO_2 [b]	State 1 hour	94.5	142.6	237.1	339	70
	Federal 1 hour [c]	--	--	126.0	188	67
	Annual	0.59	22	22.6	57	40

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
SO_2	State 1 hour	5.8	23.1	28.9	655	4
	Federal 1 hour [d]	5.8	10.5	16.3	196	8
	24 hour	1.7	3.7	5.4	105	5

Source: HBEP 2015h, HBEP 2016n, and independent staff analysis

Notes:

[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year average of 98^{th} percentile background concentrations.

[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.

[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98^{th} percentile daily modeled concentration paired with the 3-year average of 98^{th} percentile seasonal hour-of-day background concentrations.

[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year average of 99^{th} percentile background concentrations.

[e] Worst-case modeling assumed each GE 7FA.05 turbine operating at 44 percent load for 24 hours per day, which is an unlikely scenario. A more refined analysis (results shown in parentheses) assumed that one GE 7FA.05 turbine would operate at 44 percent load for 24 hours per day and the other would operate 20 hours per day at 44 percent load and 4 hours per day at 75 percent load. Staff performed additional analysis and concludes that the Amended HBEP is not likely to cause exceedance of the 24-hour PM10 standard. See more details in the text.

The 24-hour PM10 and PM2.5 impact from the Amended HBEP would exceed the CEQA significant increase level of 2.5 $\mu g/m^3$ defined by SCAQMD's CEQA guidance. This value is defined in SCAQMD Rule 1303 Table A-2. However, as an Energy Commission jurisdictional project using SCAQMD Rule 1304, the Amended HBEP turbines are exempted from Rule 1303, as well as any findings about, or comparisons to, the Significant Change in Air Quality Concentrations in Rule 1303 Table A-2. The SCAQMD PM10 and PM2.5 localized CEQA thresholds for general use should only be applied to the auxiliary boiler portion of the project. The auxiliary boiler on its own would not exceed SCAQMD PM10 and PM2.5 localized CEQA thresholds. Therefore, staff believes that the Amended HBEP would not have a significant 24-hour PM10 impact.

Air Quality Table 13 shows that the Amended HBEP would contribute to existing violations of annual PM10 ambient air quality standard. The impacts of PM2.5 are close to the most stringent standards due to the existing high background concentrations, but are not expected to create new violations.

The direct impacts of NO_2, in conjunction with worst-case background conditions, would not create a new violation of the current federal or state NO_2 ambient air quality standard, including the new federal 1-hour NO_2 standard. The direct impacts of CO and SO_2 would also not be significant because routine operation of the project would neither cause nor contribute to a violation of these standards. Mitigation for emissions of PM10, PM2.5, SOx, NOx, and VOC would be appropriate for reducing impacts to PM10, PM2.5, and ozone.

Secondary Pollutant Impacts

The gaseous emissions of NOx, SOx, VOC, and ammonia from the Amended HBEP are precursor pollutants that can contribute to the formation of secondary pollutants (ozone, PM10, and PM2.5). 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 secondary pollutant ozone or particulate nitrate or sulfate formation from a single project or source. However, because of the known relationships of NOx and VOC to form ozone and of NOx, SOx, and ammonia emissions to form secondary PM10 and PM2.5, it can be said that unmitigated emissions of these pollutants would contribute to higher ozone and PM10/PM2.5 levels in the region. Mitigating SOx and NOx emissions would both avoid significant secondary PM10/PM2.5 impacts and reduce secondary pollutant impacts to a less than significant level.

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 the SCAQMD's requirement on the ammonia slip rate (SCAQMD 2016b), staff recommends an ammonia slip limit of 5 ppmvd in condition of certification **AQ-15**.

Fumigation Impacts

There is the potential that higher short-term concentrations of pollutants may occur during fumigation conditions. Inversion breakup fumigation occurs when a plume is emitted into a stable layer of air and that layer is then mixed to the ground in a short period of time through convective heating and microscale turbulence. Shoreline fumigation occurs when a plume is emitted into a stable layer of air and is then mixed to the surface as a result of advection of the air mass to less stable surroundings. Under both conditions, an exhaust plume may be drawn to the ground with little diffusion, causing high ground-level pollutant concentrations.

Fumigation conditions are generally short-term in nature and impacts are only compared to short-term standards (less than or equal to 8 hours [SCAQMD 2016b]). The project owner analyzed the air quality impacts during startup/shutdown hours (for CO and NOx) and normal operating hours (for PM) under fumigation conditions using the U.S. EPA recommended AERSCREEN (version 15181) model (HBEP 2015h).

Staff noticed that the plume heights from the GE 7FA.05 turbines and the auxiliary boiler would be below the Thermal Internal Boundary Layer (TIBL) at the coast, thus the AERSCREEN model did not calculate the shoreline fumigation impacts for the GE 7FA.05 turbines and the auxiliary boiler. But AERSCREEN was able to calculate the inversion breakup fumigation impacts from the GE 7FA.05 turbines and the auxiliary boiler. AERSCREEN calculates both shoreline fumigation impacts and inversion breakup fumigation impacts for the GE LMS-100PB turbines.

The project owner's fumigation analysis did not adjust the fumigation impacts for averaging periods longer than 1-hour. However, fumigation conditions are generally short-term in nature. U.S. EPA's guidance on screening procedures (U.S. EPA 1992) suggested that the effect of fumigation on averaging periods longer than 1-hour should be adjusted assuming that the fumigation impacts persist for 90 minutes. Staff performed an independent analysis assuming the fumigation impacts would persist for 90 minutes.

Air Quality Table 14
Amended HBEP, Worst-case Fumigation Impacts (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
CO	1 hour	639.4	3,450	4,089.4	23,000	18
	8 hour	128.8	2,222	2,350.8	10,000	24
NO_2 [a]	State 1 hour	125.8	142.6	268.4	339	79
SO_2	State 1 hour	12.8	23.1	35.9	655	5

Source: HBEP 2015h, HBEP 2016n, and independent staff analysis
Note:
[a] The maximum 1-hour NO_2 concentrations include ambient NO_2 ratios of 0.80.

Staff also noticed that the fumigation impacts from the GE 7FA.05 turbines, the GE LMS-100PB turbines, and the auxiliary boiler would not overlap with each other. The worst-case fumigation impacts would be from the GE 7FA.05 turbines. However, staff conservatively assumed that the worst-case fumigation impacts from the GE 7FA.05 turbines, the GE LMS-100PB turbines, and the auxiliary boiler would overlap with each other. **Air Quality Table 14** shows the worst-case fumigation impacts from staff's conservative analysis. The worst-case short-term fumigation impacts would be a little higher than those in routine operations shown in **Air Quality Table 13**, except for the 8 hour CO impacts. The worst-case fumigation impacts from the Amended HBEP combined with the worst-case background concentrations would not exceed the ambient air quality standards. Since the fumigation does not occur on a regular basis, the statistically based federal 1-hour NO_2 and 1-hour SO_2 standards are not applicable in this case.

Commissioning Phase Impacts

Commissioning phase impacts would occur over a short-term period needed to complete the commissioning. The project owner expects the total duration of the combined-cycle power block and simple-cycle power block commissioning periods to be up to 1,992 hours (996 hours per turbine) and 560 hours (280 hours per turbine) respectively. The project owner expects the duration of the auxiliary boiler commissioning would take 5 days and would require up to 6 fired hours per day. The commissioning emissions estimates are based on partial load operations before the emission control systems become operational, and are shown in **Air Quality Table 8**.

The combined-cycle power block would be built and commissioned first. The project owner assumes that both the GE 7FA.05 turbines would be commissioned simultaneously at the highest unabated emissions expected during commissioning. The project owner also assumed that the auxiliary boiler would operate with steady-state emissions during commissioning of the combined-cycle turbines. Since the existing HBGS Unit 2 would continue operating until December 2020, its operation could overlap with the commissioning of the combined-cycle power block. The project owner included the operation of the existing HBGS Unit 2 in the combined-cycle power block commissioning impacts analysis (HBEP 2016c).

The federal 1-hour NO_2 standard is expressed as a 3-year average of the 98th percentile of the daily maximum 1-hour concentration. Since this is a statistically based standard, it is not applicable to the short-duration commissioning phase. Staff does not expect it to have significant impact due to the very limited commissioning period compared to the 3-year averaging time used for the standard. Impacts due to PM10, PM2.5, and SO_2 during commissioning would occur under similar exhaust conditions as those for startup while in routine operation because these emissions are proportional to fuel use. As a result, staff expects that the SO_2, PM10, and PM2.5 impacts from commissioning activities would be the same as those from normal operation, as shown in **Air Quality Table 13**.

Air Quality Table 15 shows that the commissioning phase emissions of the GE 7FA.05 combined-cycle turbines (with simultaneous operation of HBGS Unit 2) would not cause new exceedances of any state or federal ambient air quality standard. The project owner also modeled the impacts due to the commissioning of the simple-cycle power block. The simple-cycle power block would be commissioned after the combined-cycle power block is already in operation. The project owner assumed that the two GE LMS-100PB simple-cycle turbines would undergo commissioning simultaneously with the highest unabated emissions shown in **Air Quality Table 8**. The project owner also assumed that both the GE 7FA.05 combined-cycle turbines and the auxiliary boiler would operate with steady-state emissions during commissioning of the simple-cycle turbines.

Air Quality Table 16 shows that the commissioning phase emissions of the GE LMS-100PB simple-cycle turbines would not cause new exceedances of any state or federal ambient air quality standard.

Air Quality Table 15
Amended HBEP, GE 7FA.05 Commissioning Phase Maximum Impacts ($\mu g/m^3$)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
CO	1 hour	4,372	3,450	7,822	23,000	34
	8 hour	3,018	2,222	5,240	10,000	52
NO_2	1 hour (state) [a]	170	142.6	313	339	92
	Annual [b]	0.72	22	23	57	40

Source: HBEP 2016c, HBEP 2016n, and independent staff analysis
Notes:
[a] The maximum 1-hour NO_2 impact is based on AERMOD PVMRM output with an in-stack NO_2/NOx ratio of 0.5 and an out-of-stack NO_2/NOx ratio of 0.9.
[b] The maximum annual NO_2 concentrations include ambient NO_2 ratio of 0.75.

Air Quality Table 16
Amended HBEP, GE LMS-100PB Commissioning Phase Maximum Impacts ($\mu g/m^3$)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
CO	1 hour	527	3,450	3,977	23,000	17
	8 hour	131	2,222	2,353	10,000	24
NO_2 [a]	1 hour (state)	79.1	142.6	222	339	65
	Annual	0.51	22	23	57	39

Source: HBEP 2015h, HBEP 2016n, and independent staff analysis
Note:
[a] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.

Mitigation for Routine Operation

Project Owner's Proposed Mitigation

The Amended HBEP includes a combination of BACT and emission reduction credits to mitigate air quality impacts. The equipment description, equipment operation, and emission control devices are provided in Project Description and Proposed Emissions (above).

Emission Controls

The project owner proposes the use of dry low NOx combustors with selective catalytic reduction (SCR) to control NOx emissions to 2.0 ppmvd (1-hour average) for the GE 7FA.05 combined-cycle turbines and 2.5 ppmvd (1-hour average) for the GE LMS-100PB simple-cycle turbines. The project owner proposes the use of low NOx burners with flue gas recirculation and SCR to control NOx emissions of the auxiliary boiler to 5.0 ppmvd corrected to 3 percent oxygen. The BACT for CO emissions is best combustion design and the installation of an oxidation catalyst system to reduce CO to 2.0 ppmvd for the GE 7FA.05 combined-cycle turbines and 4.0 ppmvd (1-hour average) for the GE LMS-100PB simple-cycle turbines. The project owner proposes to use flue gas recirculation and good combustion design to control CO emissions of the auxiliary boiler to 50 ppmvd.

The BACT for VOC emissions is best combustion design and the installation of an oxidation catalyst system to control VOC emissions to 2.0 ppmvd (1-hour average) for the GE 7FA.05 turbines and the GE LMS-100PB turbines. The use of clean burning natural gas and good combustion design for VOC control is BACT for the auxiliary boiler. Using best combustion practices, pipeline-quality natural gas, and inlet air filtration to limit PM10/PM2.5 emissions to 8.5 lbs/hr for the GE 7FA.05 turbines, 6.24 lbs/hr for the GE LMS-100PB turbines, and 0.51 lb/hr for the auxiliary boiler are consistent with BACT at other similar sources. Operating exclusively on low sulfur pipeline-quality natural gas with a maximum fuel sulfur content of 0.75 grains/100 scf is the BACT for SOx.

Emission Offsets

SCAQMD Rule 1303(b)(2) requires that all increases in emissions be offset unless exempt from offset requirements pursuant to SCAQMD Rule 1304, as described below.

SCAQMD Rule 1304(a)(2) – Electric Utility Steam Boiler Replacement states that if electric utility steam boilers are replaced by combined cycle gas turbine(s), advanced gas turbines (including intercooled turbines), or renewables, the project would be exempt from emission offset requirements for non-RECLAIM pollutants unless there is a basin-wide electricity generation capacity increase on a per-utility basis. If there is an increase in basin-wide capacity, only the increased capacity must be offset via traditional offset rules and regulations. The language of this exemption allows for exemptions from offset and modeling normally required if the in-basin megawatt capacity of the utility receiving the facility's energy does not increase. The purpose was to facilitate the removal of older and less efficient boiler/steam turbine technology with cleaner gas turbine technology at the utilities. Since the advent of RECLAIM, the exemption was expanded to include modifications conducted for compliance with Regulation XX rules.

The SCAQMD's PDOC shows the total power generating capacity from the proposed turbines would be 895.5 MW gross. The Amended HBEP output would be limited by conditions of certification **AQ-56** (SCAQMD condition E448.1) and **AQ-57** (SCAQMD condition E448.2). In order to qualify for the exemption, the project owner is proposing to shut down HBGS Units 1 and 2 and RBGS Unit 7. The capacity of each of the HBGS Units 1 and 2 is 215 MW gross. The capacity of RBGS Unit 7 is 480 MW gross. The total capacity of the units being shutdown would be 910 MW gross. Therefore the net megawatts would decrease and the new power generating system would qualify for the Rule 1304(a)(2) exemption. Thus, the facility does not have to provide emission reduction credits for VOC and PM10 emissions of the new turbines. Instead, the VOC and PM10 emissions of the new turbines would be fully offset from SCAQMD's internal bank. However, SCAQMD decided that the auxiliary boiler and oil/water separators are not eligible for exemption under Rule 1304(a)(2) and the project owner is required to provide offsets for these emissions. Offsets for non-RECLAIM pollutants VOC and PM10 (offsets for CO emissions are not required) for these equipment would be provided in the form of ERCs.

SCAQMD Rule 1304.1 – Electrical Generating Fee for Use of Offset Exemption requires electrical generating facilities which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay fees for up to the full amount of offsets provided by the SCAQMD in accordance with Rule 1304. The project owner would be required to demonstrate compliance with the specific requirements of this rule prior to issuance of the Permits to Construct for the Amended HBEP. However, the timing and location(s) of these offsets would not be determined until that time.

Under Rule 2005, RTCs to cover the expected emissions of NOx for the Amended HBEP are required to be held for the first compliance year. Additionally, since the NOx PTE after the first year would be less than the facility's initial allocation (1,276,547 lbs/yr [SCAQMD 2016b]), the facility is not required to hold NOx RTCs for subsequent years. But the SCAQMD will make sure the facility has enough NOx RTCs for its actual emissions. The Huntington Beach facility is also in the SOx RECLAIM program. Therefore, SOx RTCs are required to be held to cover the first year of operation. Additionally, because the facility opted into SOx RECLAIM after 1994, there is no initial allocation. For this reason, SOx RTCs are required to be held for each compliance year after the first year of operation [paragraph (f)(1)].

Air Quality Table 17 shows the CEQA mitigation that is provided for the emission impacts from the Amended HBEP, which is based on the NSR offsets/emissions identified in the SCAQMD's PDOC (SCAQMD 2016b) and staff's own analysis.

The emissions shown in **Air Quality Table 17** are calculated from the maximum monthly emissions limits in the PDOC divided by 30 to produce the 30-day average lbs/day values (with the exception of NOx and SOx, which are pounds per year). Staff has found it appropriate to use the 30-day average lbs/day value for characterizing the project emission profile in the SCAQMD. That is due to the fact that the SCAQMD calculates ERCs on a 30-day lb/day average value as described below.

The project's emissions on a 30-day average is calculated by totaling the worst case month that the project is expected to have and dividing that total by 30 to create an estimate of the 30-day averaged daily emissions. A project must obtain ERCs for the 30-day average lbs/day value. A lbs/day average based on an annual average is always going to be lower than a lbs/day average based on a worst case month for the same emitting source. Any emitting source will always have a month where it emits more pollutants than any other month, but in an annual average this peak month is washed out over the year. Thus the lbs/day ERC calculation is more conservative than the lbs/day annual average emission calculation. Therefore, for projects located in the SCAQMD, staff uses the 30-day average lbs/day value to characterize the project emissions profile when comparing it to the ERCs being offered.

The VOC and PM10 emissions offsets requirement for the auxiliary boiler and oil/water separators are based on the 30-day average emissions multiplied by an offset ratio of 1.2:1 according to SCAQMD Rule 1303. The project owner will have to provide ERCs of 4 lbs/day of VOC and 5 lbs/day of PM10 for the auxiliary boiler and 1 lb/day of VOC for the oil/water separators as shown in **Air Quality Table 17**.

Air Quality Table 17 [a]
CEQA Mitigation (30-day average lbs/day)

	NOx (lbs/year) [b]	VOC	PM10	SOx (lbs/year) [c]
Amended HBEP				
RTCs for the combined-cycle turbines during commissioning year	294,186	0	0	29,606 (19,920)
RTCs for the simple-cycle turbines during commissioning year	53,940			3,320 (2,402)
1304 Exemption Credits	0	639	731	0
RTCs or ERCs for auxiliary boiler	1,313	4	5	382
ERCs for oil/water separators	0	1	0	0
Total Credits	295,499 (53,940)	644	736	29,988 (22,704)
CEQA Mitigation Needed	295,499 (53,940)	642.3	735.1	29,988 (22,704)
Further Mitigation Needed	None	None	None	None
Licensed HBEP				
Emission Reduction Credits or RECLAIM Trading Credits	314,054 (501,972)	0	0	21,638 (30,504)
1304 Exemption Credits	0	1,497.6	855.6	0

	NOx (lbs/year) [b]	VOC	PM10	SOx (lbs/year) [c]
Total Credits	314,054 (501,972)	1,497.6	855.6	21,638 (30,504)
CEQA Mitigation Needed	314,054 (501,972)	1,497.6	855.6	21,638 (30,504)
Further Mitigation Needed	None	None	None	None

Source: CEC 2014bb, SCAQMD 2016b, and independent staff analysis
Note:
[a] Values are subject to refinement in FDOC and FSA.
[b] The NOx emissions and RTCs are shown for the combined-cycle turbines commissioning year and simple-cycle turbines commissioning year (shown in parentheses), which do not overlap with each other. The auxiliary boiler emissions are included in the emissions during the combined-cycle turbines commissioning year. Since the NOx PTE after the first year would be less than the facility's initial allocation, the facility is not required to hold NOx RTCs for subsequent years.
[c] The SOx emissions for the commissioning years would be higher than non-commissioning years. All SOx emissions for both commissioning year and non-commissioning years (shown in parentheses) would be offset by RTCs. The combined-cycle turbines commissioning year and simple-cycle turbines commissioning year do not overlap with each other. In the above table, staff provided the total SOx RTC requirements (29,988 lbs/year) of the Amended HBEP during the worst year, which is the commissioning year for the combined-cycle turbines. Staff also provided the total SOx RTC requirements (22,704 lbs/year) for a normal operation year in the parentheses. Due to space limitations, the table does not show the total SOx RTC requirements for interim years after the combined-cycle turbines commissioning year prior to simple-cycle turbines commissioning year, which would be 20,302 lbs/year. For the simple-cycle turbines commissioning year, the total SOx RTC requirements would be 23,622 lbs/year. However, instead of computing the total RTC requirements for the facility, the SCAQMD specifies SOx RTC requirements for each equipment for the first year of operation (commissioning year) and each subsequent year.

SCAQMD Rule 1325 requires a major PM2.5 facility to offset PM2.5 emissions at the offset ratio of 1.1:1. A major polluting facility is defined in the rule as a facility which has actual emissions, or a potential to emit of greater than 100 tons per year. The Amended HBEP would not be a major PM2.5 facility because the total PM2.5 potential to emit of the Amended HBEP would be 69.6 tons per year, which is less than the 100 tons per year threshold (or 70 tons per year after August 14, 2017 or earlier if the SCAQMD adopts the revised threshold by amending this rule prior to that date [see more details in the section that discusses compliance with Rule 1325]). Therefore, no PM2.5 offsets are required for the Amended HBEP.

Because the facility area is classified as attainment for CO, the SCAQMD NSR regulations do not require ERCs for this pollutant. Staff does not require mitigation for this pollutant other than the installation of BACT and modeling to show that the Amended HBEP does not cause or contribute to a violation of a CO ambient air quality standard.

Air Quality Table 17 also shows CEQA mitigation needed for the licensed HBEP for comparison purposes. The CEQA mitigation needed for the Amended HBEP would be less than that for the licensed HBEP, except for the SOx RTCs required during commissioning years of the Amended HBEP because SOx emissions estimated during the commissioning years of the Amended HBEP would be higher than those estimated for the licensed HBEP.

Adequacy of Proposed Mitigation

Staff believes that the NOx and SOx RTCs are a valid mechanism to mitigate the NOx and SOx emissions due to the extensive monitoring and reporting requirement for the RECLAIM program.

Energy Commission staff has long recommended that mitigation be provided by projects certified by the Energy Commission to address adverse air quality impacts. Emission reductions of nonattainment pollutants and their precursors at a minimum overall one-to-one ratio of annual operating emissions can provide this mitigation. For the proposed new turbines at the Amended HBEP, the SCAQMD would provide PM10 and VOC emission offsets from its internal bank that would meet or exceed a one-to-one offset ratio. The project owner is required to surrender 4 lbs/day of VOC and 5 lbs/day of PM10 ERCs for the auxiliary boiler and 1 lb/day of VOC ERCs for the oil/water separators to the SCAQMD prior to commencing construction of the Amended HBEP.

Staff concludes that adverse impacts are mitigated for CEQA purposes by these emissions reductions. These offsets are required before beginning construction.

The PM10 emissions of the new turbines would be fully offset from the SCAQMD's internal bank. The SCAQMD would not require PM2.5 offsets because the Amended HBEP would not be a major PM2.5 facility, based on annual emissions. However, most of the PM emissions from a natural gas power plant are predominately PM2.5 (i.e., they are combustion related PM). Since the PM10 credits in the SCAQMD's internal bank that are being used to satisfy the project's PM10 requirements are also generally from combustion sources, staff believes that the PM10 emissions offsets from the SCAQMD's internal bank would mitigate the PM10/PM2.5 direct impacts of the Amended HBEP to less than significant. As discussed above, the relationship of PM10/PM2.5 precursors to PM is well known, although the conversion process is complex. Staff concludes that providing CEQA mitigation for PM and their precursors will reduce PM10/PM2.5 impacts to less than significant for the Amended HBEP.

As shown in **Air Quality Table 17**, there would be sufficient mitigation credits to fully offset facility operating period emissions that would be expected to occur at the site from the Amended HBEP.

Staff's evaluation of the adequacy of project mitigation was determined solely based on the merits of this case, including the SCAQMD offset requirements, the project's emission limits, the specific ERCs proposed, and ambient air quality considerations of the region, and does not in any way provide a precedence or obligation for the acceptance of offset proposals for any other current or future licensing cases.

Staff Proposed Mitigation

Staff proposes to keep the approved conditions of certification **AQ-SC7** to ensure that the license is amended as necessary to incorporate any future changes to the air quality permits and to ensure ongoing compliance during commissioning and routine operation through quarterly reports (**AQ-SC8**). Staff also proposes a new Condition of Certification (**AQ-SC9**) to ensure that the emissions of the auxiliary boiler and the oil/water separators would be mitigated with the quantity of SCAQMD offsets recommended by the SCAQMD and Energy Commission staff and to ensure agency consultation if substitutions are made to the credits.

Overlap Periods Impacts and Mitigation

Due to the 10-year construction period, some construction/demolition activities would overlap with the operation of the existing HBGS Units 1 and 2 and commissioning and operation of the proposed new units for the Amended HBEP. The project owner modeled impacts for all possible overlapping periods (listed below) as requested by staff. For the statistically based standards (federal 1-hour NO_2 and SO_2, 24-hour PM2.5), the modeling assumes the overlap would occur during the full 3 years, which will overestimate the impacts. Therefore the modeling results for these standards are extremely conservative.

A. Combined-cycle power block operation with simultaneous construction of the simple-cycle power block

This scenario is intended to determine modeled impacts from the simultaneous operation of the combined-cycle power block and construction of the simple-cycle power block (2nd quarter 2022 to 4th quarter 2023). The maximum impacts for this scenario are presented in **Air Quality Table 18** with **bold** used to indicate exceedances.

Staff believes that PM10 emissions during this overlap period (up to 20 months) would cause significant impacts because they would cause a new exceedance of the 24-hour PM10 standard and would also contribute to the existing violation of the annual PM10 standard. The significant PM impacts are mainly due to high background concentrations and fugitive dust emissions during the construction period. However, the mitigation measures included in conditions of certification **AQ-SC1** through **AQ-SC6** are expected to reduce the potential for significant adverse air quality impacts as much as possible during construction. In addition, mitigation measures proposed for the operation of the Amended HBEP would reduce potential impacts of the Amended HBEP to less than significant. The direct impacts of CO, NO_2, SO_2 and PM2.5 would be less than significant because they would neither cause nor contribute to a violation of these standards.

B. Amended HBEP operation with simultaneous demolition of HBGS Units 1 and 2

This scenario is intended to determine impacts from the simultaneous operation of the Amended HBEP units (combined-cycle power block and simple-cycle power block) and demolition of HBGS Units 1 and 2 (1st quarter 2024 to 4th quarter 2025). The maximum impacts for this scenario are presented in **Air Quality Table 19** with **bold** used to indicate exceedances.

Air Quality Table 19 shows that the PM10 emissions during this overlap period (up to 24 months) would cause a new exceedance of the 24-hour PM10 standard and would also contribute to the existing violation of the annual PM10 standard. The exceedance is mainly due to high background concentrations and fugitive dust emissions during the demolition period. However, the mitigation measures included in Conditions of Certification **AQ-SC1** through **AQ-SC6** are expected to reduce the potential for significant adverse air quality impacts as much as possible during construction.

Air Quality Table 18
Amended HBEP, Maximum Impacts from Combined-cycle Power Block Operation and Simple-cycle Power Block Construction (µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	9.3	45	**54.3**	**50**	**108.7**
	Annual	0.9	**24.2**	**25.1**	**20**	**125**
PM2.5	24 hour [a]	5.1	27.8	32.9	35	94
	Annual	0.64	11.34	11.98	12	99.9
CO	1 hour	630.6	3,450	4,080.6	23,000	18
	8 hour	149.3	2,222	2,371.3	10,000	24
NO_2 [b]	State 1 hour	94.3	142.6	236.9	339	70
	Federal 1 hour [c]	--	--	126.0	188	67
	Annual	0.65	22	22.65	57	40
SO_2	State 1 hour	5.8	23.1	28.9	655	4
	Federal 1 hour [d]	5.8	10.5	16.3	196	8
	24 hour	1.7	3.7	5.4	105	5

Source: HBEP 2015h, HBEP 2016n, and independent staff analysis
Notes:
[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year average of 98th percentile background concentrations.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.
[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year average of 99th percentile background concentrations.

Air Quality Table 19 also shows that the worst-case total annual PM2.5 impacts during this overlap period would be equal to the limiting annual PM2.5 standard of 12 µg/m^3 due to the existing high background concentrations. The worst-case annual PM2.5 project impacts during this overlap period would be mainly from the operation of the Amended HBEP, with a portion of the impacts from demolition of HBGS Units 1 and 2. The project owner's modeling conservatively assumed that both the GE 7FA.05 combined-cycle turbines would continuously operate at 44 percent load, which is unlikely to occur. Annual impacts from other operating scenarios would be less than those modeled for the 44 percent load scenario. The project owner agreed to accept a permit condition (SCAQMD condition C1.9 [**AQ-24**]) to limit the simultaneous operation of the combined-cycle turbines at 44 percent load to less than 20 consecutive hours. Therefore, the total annual PM2.5 impacts would be less than the limiting standard of 12 µg/m^3. In addition, mitigation measures proposed for the operation of the Amended HBEP and construction/demolition activities would reduce potential impacts of the Amended HBEP to less than significant.

The 24-hour PM2.5 impacts would be close to the most stringent standards due to the existing high background concentrations, but would not cause new violations. The direct impacts of CO, NO_2, and SO_2 would be less than significant because they would neither cause nor contribute to a violation of these standards.

Air Quality Table 19
Amended HBEP, Maximum Impacts from Amended HBEP Operation and HBGS Units 1 and 2 Demolition (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	5.8	45	**50.8**	**50**	**101.6**
	Annual	1.0	**24.2**	**25.2**	**20**	**126**
PM2.5	24 hour [a]	5.1	27.8	32.9	35	94
	Annual	0.66	11.34	12.00	12	100
CO	1 hour	634.4	3,450	4,084.4	23,000	18
	8 hour	152.5	2,222	2,374.5	10,000	24
NO_2 [b]	State 1 hour	94.8	142.6	237.4	339	70
	Federal 1 hour [c]	--	--	126.2	188	67
	Annual	0.74	22	22.74	57	40
SO_2	State 1 hour	5.8	23.1	28.9	655	4
	Federal 1 hour [d]	5.8	10.5	16.3	196	8
	24 hour	1.7	3.7	5.4	105	5

Source: HBEP 2015h, HBEP 2016n, and independent staff analysis
Notes:
[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year average of 98th percentile background concentrations.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.
[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year average of 99th percentile background concentrations.

C. Combined-cycle power block operation with simultaneous demolition of HBGS Units 3 and 4, and operation of HBGS Unit 2

This scenario is intended to determine impacts from the simultaneous operation of the combined-cycle power block, demolition of HBGS Units 3 and 4 (1st/2nd quarter 2020 to 4th quarter 2021), and operation of HBGS Unit 2. The project owner plans to retire HBGS Unit 2 by the end of 2020. Therefore, the expected overlap period of this scenario would be less than a year. The maximum impacts for this scenario are presented in **Air Quality Table 20** with **bold** used to indicate exceedances.

Air Quality Table 20
Amended HBEP, Maximum Impacts from Combined-cylce Power Block Operation, HBGS Units 3 and 4 Demolition, and HBGS Unit 2 Operation (µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	5.3	45	**50.3**	**50**	**100.7**
	Annual	1.1	**24.2**	**25.3**	**20**	**126**
PM2.5	24 hour [a]	5.1	27.8	32.9	35	94
	Annual	0.54	11.34	11.88	12	99.0
CO	1 hour	654.3	3,450	4,104.3	23,000	18
	8 hour	178.7	2,222	2,400.7	10,000	24
NO_2 [b]	State 1 hour	94.3	142.6	236.9	339	70
	Federal 1 hour [c]	--	--	126.0	188	67
	Annual	0.62	22	22.62	57	40
SO_2	State 1 hour	5.8	23.1	28.9	655	4
	Federal 1 hour [d]	5.8	10.5	16.3	196	8
	24 hour	1.7	3.7	5.4	105	5

Source: HBEP 2016c, HBEP 2016n, and independent staff analysis
Notes:
[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year average of 98th percentile background concentrations.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.
[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year average of 99th percentile background concentrations.

Air Quality Table 20 shows that the PM10 emissions during this overlap period (less than a year) would cause a new exceedance of the 24-hour PM10 standard and would also contribute to the existing violation of the annual PM10 standard. The exceedance is mainly due to high background concentrations and fugitive dust emissions during the demolition period. However, the mitigation measures included in conditions of certification **AQ-SC1** through **AQ-SC6** are expected to reduce the potential for significant adverse air quality impacts as much as possible during construction/ demolition. In addition, mitigation measures proposed for the operation of the Amended HBEP would reduce potential impacts of the Amended HBEP to less than significant.

The PM2.5 impacts would be close to the most stringent standards due to the existing high background concentrations, but would not create new violations. The direct impacts of CO, NO_2, and SO_2 would be less than significant because they would neither cause nor contribute to a violation of these standards.

D. Operation of HBGS Units 1 and 2 with simultaneous construction/demolition activities for the combined-cylce power block

This scenario is intended to determine impacts from the simultaneous operation of HBGS Units 1 and 2 with the worst-case emissions from construction/demolition activities for the combined-cycle power block (1st quarter 2016 to 1st/2nd quarter 2020). The maximum impacts for this scenario are presented in **Air Quality Table 21** with **bold** used to indicate exceedances.

Air Quality Table 21
Amended HBEP, Maximum Impacts from HBGS Units 1 and 2 Operation and Combined-cylce Power Block Construction/demolition Activities (µg/m³)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	11.3	45	**56.3**	**50**	**112.6**
	Annual	3.0	**24.2**	**27.2**	**20**	**136**
PM2.5	24 hour [a]	4.4	27.8	32.2	35	92
	Annual	0.88	11.34	**12.22**	**12**	**101.9**
CO	1 hour	805.7	3,450	4,255.7	23,000	19
	8 hour	140.8	2,222	2,362.8	10,000	24
NO_2 [b]	State 1 hour	34.4	142.6	177.0	339	52
	Federal 1 hour [c]	--	--	121.1	188	64
	Annual	2.1	22	24.1	57	42
SO_2	State 1 hour	4.3	23.1	27.4	655	4
	Federal 1 hour [d]	4.3	10.5	14.8	196	8
	24 hour	0.3	3.7	4.0	105	4

Source: HBEP 2016c and independent staff analysis
Notes:
[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year average of 98th percentile background concentrations.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.
[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year average of 99th percentile background concentrations.

Air Quality Table 21 shows that the PM emissions during this overlap period (up to 52 months) would cause new exceedances of the 24-hour PM10 standard and the annual PM2.5 standard. The PM emissions would also contribute to the existing violation of the annual PM10 standard. The exceedances are mainly due to high background concentrations and fugitive dust emissions from the construction/demolition activities. However, the mitigation measures included in conditions of certification **AQ-SC1** through **AQ-SC6** are expected to reduce the potential for significant adverse air quality impacts as much as possible during construction/demolition. The 24-hour PM2.5 impacts would be close to the most stringent standards due to the existing high background concentrations, but would not cause new violations. The direct impacts of CO, NO_2, and SO_2 would be less than significant because they would neither cause nor contribute to a violation of these standards.

The commissioning of the combined-cycle power block would overlap with the operation of the HBGS Unit 2. The project owner included the operation of HBGS Unit 2 in the commissioning phase modeling for the combined-cycle power block. The maximum impacts for this scenario are presented in **Air Quality Table 15**. Commissioning activities would not cause exceedances of ambient air quality standards.

The operation of the combined-cycle power block would also overlap with the commissioning of the simple-cycle power block. The project owner has modeled the impacts for this overlap scenario by including the combined-cycle power block in the impact analysis for the simple-cycle power block during commissioning phase. The maximum impacts for this scenario are presented in **Air Quality Table 16**. Commissioning activities would not cause exceedances of ambient air quality standards.

Cumulative Impacts and Mitigation

"Cumulative impacts" are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts" (CEQA Guidelines, §15355). Such impacts can be relatively minor and incremental yet still be significant because of the existing environmental background, particularly when considering other closely related past, present, and reasonably foreseeable future projects.

Criteria pollutants have impacts that are usually (though not always) cumulative by their nature. Rarely will a project itself cause a violation of a federal or state criteria pollutant standard. However, many new sources contribute to violations of criteria pollutant standards because of elevated background conditions. Air Districts attempt to reduce background criteria pollutant levels by adopting attainment plans, which are multi-faceted programmatic approaches to attainment. Attainment plans typically include new source review requirements that provide offsets and use Best Available Control Technology, combined with more stringent emissions controls on existing sources.

The discussion of cumulative air quality impacts includes the following three analyses:

- a summary of projections for criteria pollutants by the air District and the air District's programmatic efforts to abate such pollution;

- an analysis of the project's "localized cumulative impacts" when combined with other local major emission sources; and
- a discussion of greenhouse gas emissions and global climate change impacts (in **Air Quality Appendix AIR-1**).

Summary of Projections

The SCAQMD is the agency with principal responsibility for analyzing and addressing cumulative air quality impacts, including the impacts of ambient ozone and particulate matter. The SCAQMD has summarized the cumulative impact of ozone and particulate matter on the air basin from the broad variety of its sources. Analyses of these cumulative impacts, as well as the measures the SCAQMD proposes to reduce impacts to air quality and public health, are summarized in four publicly available documents that the SCAQMD has adopted. These adopted air quality plans are summarized below.

- **Final 2012 Air Quality Management Plan** (adopted 12/07/2012)
  Link: http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/final-2012-air-quality-management-plan
- **Final 2007 Air Quality Management Plan** (adopted 06/01/2007)
  Link: http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/2007-air-quality-management-plan
- **Final Socioeconomic Report for the Final 2012 AQMP** (adopted 12/07/2012)
  Link: http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/final-socioeconomic-report-2012.pdf
- **State of California's SIP for the new federal PM2.5 and 8-hour ozone standards** (adopted July 21, 2011)
  Link: http://www.arb.ca.gov/planning/sip/2007sip/2007sip.htm

2012 Air Quality Management Plan

The following paragraphs are excerpted from the Executive Summary of the 2012 Air Quality Management Plan adopted by the SCAQMD December 7, 2012:

> *The SCAQMD adopted (December 7, 2012) the 2012 Air Quality Management Plan (AQMP) primarily in response to changes in the federal Clean Air Act (CAA). The CAA requires a 24-hour PM2.5 nonattainment area to prepare a State Implementation Plan (SIP) which must be submitted to U.S. EPA by December 14, 2012. The SIP must demonstrate attainment with the 24-hour PM2.5 standard by 2014, with the possibility of up to a five-year extension to 2019, if needed. U.S. EPA approval of any extension request is based on the lack of feasible control measures to move forward the attainment date by one year. The District's attainment demonstration shows that, with implementation of all feasible controls, the earliest possible attainment date is 2014, and thus no extension of the attainment date is needed. In addition, the U.S. EPA requires that transportation conformity budgets be established based on the most recent planning assumptions (i.e., within the last five years) and approved motor vehicle emission models. The Final Plan is based on the most recent assumptions provided by both ARB and Southern California Association of*

Governments (SCAG) for motor vehicle emissions and demographic updates and includes updated transportation conformity budgets.

The Final 2012 AQMP outlines a comprehensive control strategy that meets the requirement for expeditious progress towards attainment with the 24-hour PM2.5 NAAQS in 2014 with all feasible control measures. The Plan also includes specific measures to further implement the ozone strategy in the 2007 AQMP to assist attaining the 8-hour ozone standard by 2023. The control measures contained in the Final 2012 AQMP can be categorized as follows:

> *Basin-wide Short-term PM2.5 Measure. Measures that apply Basin-wide, have been determined to be feasible, will be implemented by the 2014 attainment date, and are required to be implemented under state and federal law. The main short-term measures are episodic, in that they only apply during high PM2.5 days and will only be implemented as needed to achieve the necessary air quality improvements.*

> *Contingency Measures. Measures to be automatically implemented if the Basin fails to achieve the 24-hour PM2.5 standard by 2014.*

> *8-hour Ozone Measures. Measures that provide for necessary actions to maintain progress towards meeting the 2023 8-hour ozone NAAQS, including regulatory measures, technology assessments, key investments, and incentives.*

> *Transportation Control Measures. Measures generally designed to reduce vehicle miles travelled (VMT) as included in SCAG's 2012 Regional Transportation Plan.*

Many of the control measures proposed are not regulatory in form, but instead focus on incentives, outreach, and education to bring about emissions reductions through voluntary participation and behavioral changes needed to complement regulations.

The Basin faces several ozone and PM attainment challenges, as strategies for significant emission reductions become harder to identify and the federal standards continue to become more stringent. California's Greenhouse Gas reductions targets under AB32 add new challenges and timelines that affect many of the same sources that emit criteria pollutants. In finding the most cost-effective and efficient path to meet multiple deadlines for multiple air quality and climate objectives, it is essential that an integrated planning approach is developed. Responsibilities for achieving these goals span all levels of government, and coordinated and consistent planning efforts among multiple government agencies are a key component of an integrated approach.

To this end, and concurrent with the development of the 2012 AQMP, the District, the Air Resources Board, and San Joaquin Valley Air Pollution Control District engaged in a joint effort to take a coordinated and integrated look at strategies needed to meet California's multiple air quality and climate goals, as well as its energy policies. California's success in reducing smog has largely relied on technology and fuel advances, and as health-based air quality standards are tightened, the introduction of cleaner technologies must keep pace. More broadly, a transition to zero- and near-zero emission technologies is necessary to meet 2023 and 2032 air quality standards and 2050 climate goals. Many of the same technologies will address air quality, climate and energy goals. As such, strategies developed for air quality and climate change planning should be coordinated to make the most efficient use of limited resources and the time needed to develop cleaner technologies.

2007 Air Quality Management Plan

The following paragraphs are excerpted from the Executive Summary of the 2007 Air Quality Management Plan adopted by the SCAQMD June 1, 2007:

The SCAQMD adopted (June 1, 2007) the 2007 Air Quality Management Plan (AQMP) primarily in response to changes in the federal Clean Air Act (CAA). The CAA requires an 8-hour ozone non-attainment area to prepare a SIP revision by June 2007 and a PM2.5 non-attainment area to submit by April 2008. The SCAQMD has decided that it is most prudent to prepare a single comprehensive and integrated SIP revision that satisfies both the ozone and PM2.5 requirements. Additionally, the U.S. EPA requires that transportation conformity budgets be established based on the most recent planning assumptions and approved motor vehicle emission model. The AQMP is based on assumptions provided by both the California Air Resources Board (ARB) and the Southern California Association of Governments (SCAG) reflecting their upcoming model (EMFAC) for motor vehicle emissions and demographic updates.

The Final 2007 AQMP relies on a comprehensive and integrated control approach to achieve the PM2.5 standard by 2015 through implementation of short-term and mid-term control measures and achieve the 8-hour ozone standard by 2024 based on implementation of additional long-term measures. In order to demonstrate attainment by the prescribed deadlines, emission reductions needed for attainment must be in place by 2014 and 2023 timeframe.

The AQMP control measures consist of four components: 1) the District's Stationary and Mobile Source Control Measures; 2) ARB's Proposed State Strategy; 3) District Staff's Proposed Policy Options to Supplement ARB's Control Strategy; and 4) Regional Transportation Strategy and Control Measures provided by SCAG.

In order to achieve necessary reductions for meeting air quality standards, all four agencies (i.e., SCAQMD, ARB, U.S. EPA, and SCAG) would have to aggressively develop and implement control strategies through their respective plans, regulations, and alternative approaches for pollution sources within their primary jurisdiction. Even though SCAG does not have direct authority over mobile source emissions, it will commit to the emission reductions associated with implementation of the 2004 Regional Transportation Plan and 2006 Regional Transportation Improvement Program which are imbedded in the emission projections. Similarly, the Ports of Los Angeles and Long Beach have authority they must utilize to assist in the implementation of various strategies if the region is to attain clean air by federal deadlines.

Although the SCAQMD has completely met its obligations under the 2003 AQMP and stationary sources subject to the District's jurisdiction account for only 12% of NOx and 37% of SOx emissions in the Basin in 2014, the Final 2007 AQMP contains several short-term and mid-term control measures aimed at achieving further NOx and SOx reductions (as well as VOC and PM2.5 reductions) from these already regulated sources. These strategies are based on facility modernization, energy conservation measures and more stringent requirements for existing equipment (e.g., space heaters, ovens, dryers, furnaces).

Clean air for this region requires ARB to aggressively pursue reductions and strategies for on-road and off-road mobile sources and consumer products. In addition, considering the significant contribution of federal sources such as marine vessels, locomotives, and aircraft in the Basin (i.e., 56% of SOx in 2014 and 37% of NOx in 2023), it is imperative that the U.S. EPA pursue and develop regulations for new and existing federal sources to ensure that these sources contribute their fair share of reductions toward attainment of the federal standards. Unfortunately, regulation of these emission sources has not kept pace with other source categories and as a result, these sources are projected to represent a significant and growing portion of emissions in the Basin. Without a collaborative and serious effort among all agencies, attainment of the federal standards would be seriously jeopardized.

Final Socioeconomic Report for the Final 2012 AQMP

The following are excerpted from the Final Socioeconomic Report for the Final 2012 AQMP adopted by the SCAQMD December 7, 2012:

The 2012 AQMP has been prepared to meet the challenge of achieving healthful air quality in the South Coast Air Basin (Basin) and the Coachella Valley. This report accompanies the 2012 AQMP and presents the potential socioeconomic impacts resulting from implementation of this Plan. The information contained herein is considered by the South Coast Air Quality Management District (District) Governing Board when taking action on the Plan.

The 2012 AQMP control strategy is comprised of a traditional command-and-control approach, voluntary/incentive programs, and advanced technologies. Short- and near-term control strategies are proposed and will be implemented by the District, local and regional governments (e.g., transportation control measures provided in the 2012 Regional Transportation Plan), and the California Air Resources Board (ARB). These strategies include basin-wide short-term PM2.5 measures, episodic control measures for high PM2.5 days, measures to partially implement the Section 182(e)(5) commitment in the 2007 ozone SIP toward meeting the 8-hour ozone standard by 2024, and transportation control measures (TCM) adopted by the Southern California Association of Governments (SCAG). Many of the measures require behavioral changes and voluntary participation through outreach, incentive, and education. Implementation of these control strategies has potential effects on the region's economy.

The District relies on a number of methods, tools, and data sources to assess the impact of proposed control strategies on the economy. The involved applications include: integration of air quality data and concentration-response relationships to estimate benefits of clean air; capital, operating and maintenance expenditures on control devices and emission reductions to assess the cost of the Plan; and REMI (Regional Economic Models, Inc.) model to assess potential employment and other socioeconomic impacts (e.g., population and competitiveness).

Over the years, there has been an overall trend of steady improvement in air quality in the Basin. Additional emission reductions are still needed in order to bring the Basin into compliance with the federal 24-hour PM2.5 standard. Complying with the air quality standard would allow the District to avoid potential sanctions that could increase offset ratios for major sources and result in suspension of highway transportation funding. The benefits of better air quality through implementation of the 2012 AQMP include reductions in morbidity and mortality, visibility improvements, reduced expenditures on refurbishing building surfaces, and reduced traffic congestion.

The Draft 2012 Plan is projected to comply with the federal PM2.5 standard with an average annual benefit of $10.7 billion between 2014 and 2035. The $10.7 billion includes approximately $7.7 billion for congestion relief for all TCMs in the 2012 RTP, $2.2 billion for averted illness and higher survival rates, $696 million for visibility improvements, and $14 million for reduced damage to materials.

The analysis contained herein estimates that the benefits for the Plan significantly outweigh the anticipated costs. The measurement of clean air benefits is performed indirectly since clean air is not a commodity purchased or sold in a market. This often results in incomplete and underestimated benefits. The benefits of clean air (based on the total emission reductions required for attainment) for which a monetary figure can be applied are estimated to be $10.7 billion (including congestion relief benefits for all the TCMs) as compared to the estimated costs of $448 million on an average annual basis. There are, however, many benefits which are still unaccounted for, such as reductions in chronic illness and lung function impairment in human beings, reduced damage to livestock and plant life, erosion of building materials, and the value of reduced vehicle hours traveled for personal trips.

The Plan is designed to bring northwest Riverside (the Mira Loma area), the only area in exceedance of the federal PM2.5 standard, into attainment. However, PM2.5 air quality benefits occur throughout the Basin. The San Fernando Valley, southern Los Angeles County, and the northwest Riverside County would experience the highest shares of air quality benefits. The western portions of Los Angeles and Orange Counties and the eastern and northern portions of San Bernardino County are projected to have the highest shares of health benefits.

Implementation of PM2.5 and ozone measures would impose costs on various communities. The sub-regions with the highest costs are the central, southeast, and San Fernando areas of Los Angeles County. These three areas are projected to have the highest cost shares from SCAG TCMs and relative higher cost shares from ozone measures.

All sub-regions are projected to have additional jobs created from cleaner air. The eastern, southern, and San Fernando sub-regions in Los Angeles County and Riverside County are projected to have more jobs created than other sub-regions resulting from clean air benefits. Implementation of quantified control measures would result in jobs forgone between 2013 and 2035. Orange County is projected to have the highest share of jobs forgone from implementation of control measures. This is because the majority of SCAG transportation control measures (TCM) in Orange County would be financed by development fees, which would have a heavy burden on one single sector of the economy—the construction sector. For the entire Plan, all sub-regions would show positive job impacts as the four-county area becomes more competitive and attractive with the progress in clean air.

Job gains from cleaner air would benefit all wage groups. Conversely, all five groups would experience jobs forgone from control measures. However, there is no significant difference in impacts expected for high- versus low-paying jobs. The same is observed for impacts on the price of consumption goods from one income group to another. These findings will be further evaluated during individual rule development.

State of California SIP for the new federal PM2.5 and 8-hour Ozone Standards (adopted July 21, 2011)

On April 28, 2011, the ARB considered revisions to the South Coast (and San Joaquin Valley) State Implementation Plans (SIPs) for PM2.5 that accounted for reductions of emissions that contribute to PM2.5 levels. The revisions were formally adopted by the ARB's Executive Officer on May 18, 2011, when Executive Order S-11- 010 was signed. The April 2011 PM2.5 SIP Revisions accounted for recent regulatory actions and recessionary impacts on emissions that occurred after the South Coast (and San Joaquin Valley) PM2.5 SIPs were adopted in 2007 and 2008. Those revisions accounted for the impact the recession has had on emissions and the benefits of ARB's in-use diesel truck and off-road equipment regulations. The revisions updated the PM2.5 SIP's reasonable further progress calculations, transportation conformity budgets, and ARB's rulemaking calendar.

Localized Cumulative Impacts

The Amended HBEP and other reasonably foreseeable projects could cause impacts that would be locally combined and future projects would introduce stationary sources that are not included in the "background" conditions. Reasonably foreseeable future projects are those that are either currently under construction or in the process of being approved by a local air district or municipality. Projects that have not yet entered the approval process do not normally qualify as "foreseeable" since the detailed information needed to conduct this analysis is not available. Sources that are presently operational are included in the background concentrations. Background conditions also take into account the effects of non-stationary sources.

Projects with stationary sources located up to six miles from the proposed project site usually need to be considered by the cumulative analysis. The project owner requested that the SCAQMD identify potential new stationary sources within six miles of the Amended HBEP site. Since SCAQMD has not provided a complete dataset, the project owner proposes to use the cumulative sources (as shown below) previously submitted to the Energy Commission and approved for the licensed HBEP. If final input is received from SCAQMD prior to issuance of the Final Staff Assessment, the project owner will revise the cumulative air quality impacts assessment (HBEP 2016i).

In addition to the Amended HBEP, the project owner included sources from three facilities in the cumulative analysis:

- Orange County Sanitation District (Facility ID 17301) located in Fountain Valley, CA;
- Orange County Sanitation District (Facility ID 29110) located in Huntington Beach, CA;
- Arlon Graphics, LLC (Facility ID 167066).

The maximum modeled cumulative impacts are presented below in **Air Quality Table 22**. The total impact is conservatively estimated by the maximum modeled impact plus existing maximum background pollutant levels.

Air Quality Table 22 shows that with the worst-case modeled 24-hour PM10 cumulative impact of 5.1 μg/m^3 and maximum background at 45 μg/m^3, the total 24-hour PM10 impact would be 50.1 μg/m^3, which is above the 24-hour PM10 CAAQ of 50 μg/m^3. The worst-case modeled 24-hour PM10 cumulative impact is mainly due to the operation of the Amended HBEP. However, as shown in the text below **Air Quality Table 13**, by combining the worst-case modeled impacts with the maximum background, it is conservatively assumed that they would occur at the same time.

Staff performed an independent analysis by pairing 1) worst-case modeled impacts (assuming both GE 7FA.05 turbines at 44 percent load for 24 hours per day for worst-case analysis) with background measured on the same day, and 2) the maximum background with modeled impacts on that day. The worst-case cumulative 24-hour PM10 impact of 5.1 μg/m^3 was modeled to occur on June 8, 2012. Staff downloaded the background 24-hour PM10 monitored at North Long Beach station from ARB's website (ARB 2016c). Staff found that the background 24-hour PM10 measured on June 8, 2012 was 33 μg/m^3. With the worst-case modeled cumulative 24-hour PM10 impact of 5.1 μg/m^3, the total impact would be 38.1 μg/m^3 which would be less than the 24-hour PM10 CAAQ of 50 μg/m^3. Therefore, the Amended HBEP, along with other cumulative sources, would not cause exceedance of the 24-hour PM10 CAAQ of 50 μg/m^3 on the day when the worst-case cumulative impact is modeled. The second highest modeled cumulative 24-hour PM10 impact would be less than 5 μg/m^3, thus the Amended HBEP, along with other cumulative sources, would not cause exceedance of the 24-hour PM10 CAAQ of 50 μg/m^3 if the second highest modeled impact is combined with the maximum background at 45 μg/m^3. In addition, the maximum background 24-hour PM10 of 45 μg/m^3 was monitored to occur on January 4, 2012. The highest modeled cumulative 24-hour PM10 impacts on that day would be 0.47 μg/m^3. The total 24-hour PM10 impact would be 45.47 μg/m^3 on that day. Therefore, the Amended HBEP, along with other cumulative sources, would not cause exceedance of the 24-hour PM10 CAAQ of 50 μg/m^3 on the day when the maximum background 24-hour PM10 was monitored.

Air Quality Table 22
Amended HBEP, Ambient Air Quality Impacts from Cumulative Sources (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	5.1	45	**50.1**	**50**	**100.3**
	Annual	0.65	**24.2**	**24.9**	**20**	**124**
PM2.5	24 hour [a]	5.1	27.8	32.9	35	94
	Annual	0.65	11.34	11.99	12	99.9
CO	1 hour	630.6	3,450	4,080.6	23,000	18
	8 hour	149.0	2,222	2,371.0	10,000	24
NO_2 [b]	State 1 hour	94.5	142.6	237.1	339	70
	Federal 1 hour [c]	--	--	126.0	188	67
	Annual	0.68	22	22.7	57	40

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
SO_2	State 1 hour	6.0	23.1	29.1	655	4
	Federal 1 hour [d]	6.0	10.5	16.5	196	8
	24 hour	1.7	3.7	5.4	105	5

Source: HBEP 2016n and independent staff analysis
Notes:
[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year average of 98th percentile background concentrations.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.
[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year average of 99th percentile background concentrations.

Air Quality Table 22 also shows that the Amended HBEP, along with other cumulative sources, would not cause new exceedances for PM2.5, CO, NO_2, and SO_2. However, PM10 emissions from the Amended HBEP would be cumulatively considerable because they would contribute to the existing violations of annual PM10 ambient air quality standards.

The project owner would mitigate emissions through the use of SCAQMD required best available control technology (BACT) and offsets. Therefore, the cumulative operating impacts after mitigation are considered to be less than significant.

Since the Amended HBEP is subject to PSD regulation for NO_2, CO and PM10, the project impacts must be below the PSD Significant Impact Levels (SILs) and applicable preconstruction monitoring thresholds for these pollutants or an increments analysis and/or preconstruction monitoring may be required. The CO, annual PM10, and annual NO_2 impacts from the Amended HBEP shown in **Air Quality Table 13** would be below corresponding SILs. The 24-hour PM10 impacts would also be less than the SILs with the project owner's refined analysis (HBEP 2015h) and a permit condition (SCAQMD condition C1.9 [**AQ-24**]) to limit the operating parameters of the project, as agreed to by the project owner. Therefore, no additional PSD analysis for 24-hour PM10 is required. However, the maximum 1-hour NO_2 impacts would exceed the applicable NO_2 SIL (7.52 $\mu g/m^3$), so an increments analysis is required for NO_2 impacts. The SCAQMD and U.S. EPA identified following sources to include in the 1-hour NO_2 cumulative analysis:

- Huntington Beach Generating Station Units 1 and 2
- Orange County Sanitation – Fountain Valley
- Orange County Sanitation – Huntington Beach
- Beta Offshore
- Shipping Lanes

Air Quality Table 23 shows the federal 1-hour NO_2 impacts from the Amended HBEP and the cumulative sources. As shown in **Air Quality Table 23**, the Amended HBEP with cumulative sources would not cause new exceedances of the federal 1-hour NO_2 standard. Therefore, no additional PSD analysis is necessary.

Air Quality Table 23
Amended HBEP, Federal 1-hour NO_2 Impacts from Cumulative Sources (µg/m³)

Pollutant	Averaging Time	Total Impact [b]	Limiting Standard	Percent of Standard
NO_2 [a]	1 hour (federal)	144	188	77

Source: HBEP 2015h and independent staff analysis
Notes:
[a] The 1-hour NO_2 concentrations include ambient NO_2 ratio of 0.80.
[b] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.

Environmental Justice Impacts

The **Socioeconomics** section of this document does not identify the presence of an environmental justice community within six miles of the Amended HBEP. The staff-proposed CEQA mitigation measures noted as conditions of certification would reduce the Amended HBEP's direct and cumulative **Air Quality** impacts to a less than significant level. Therefore, there are no **Air Quality** environmental justice issues related to the Amended HBEP and no minority or low-income populations would be significantly or adversely impacted.

CONCLUSIONS AND RECOMMENDATIONS

Staff has the following conclusions about the Amended HBEP and recommends the adoption of the revised and new conditions of certification:

- Construction and demolition impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff proposes to keep the approved conditions of certification **AQ-SC1** through **AQ-SC5** and revise **AQ-SC6** to mitigate the Amended HBEP's construction and demolition impacts. Due to the long construction/demolition period (120 months) and the complexity of construction/demolition activities, compliance with these conditions would be critical to reduce construction/demolition impacts.
- Operation of the project would comply with applicable SCAQMD rules and regulations, including New Source Review, BACT requirements, and requirements to offset emission increases. Staff proposes to keep the approved conditions of certification **AQ-SC7** and **AQ-SC8** to ensure that the license is amended as necessary to incorporate any future changes to the air quality permits and to ensure ongoing compliance during commissioning and routine operation through quarterly reports. Staff proposes a new condition of certification (**AQ-SC9**) to ensure that the emissions of the auxiliary boiler and the oil/water separators would be mitigated with the quantity of SCAQMD offsets recommended by the SCAQMD and Energy Commission staff and to ensure agency consultation if substitutions are made to the credits. Staff proposes to delete the approved conditions of certification **AQ-1** through **AQ-43** for the licensed HBEP and recommends the inclusion of the

SCAQMD's new conditions as new Conditions of Certification **AQ-1** through **AQ-66** (SCAQMD 2016c) for the Amended HBEP.

- Implementation of the conditions of certification, and the air quality conditions and practices described in the analysis would reduce potential adverse impacts to insignificant levels and ensure that the project's emissions are mitigated to less than significant.
- With the adoption of the attached conditions of certification, the Amended HBEP would comply with all applicable laws, ordinances, regulations, and standards related to air quality as described in pertinent portions of this analysis.

PROPOSED CONDITIONS OF CERTIFICATION

Staff has proposed modifications to the Air Quality conditions of certification. Most of the approved conditions of certification **AQ-1** through **AQ-43** for the licensed HBEP don't apply to the Amended HBEP or need to be substantially revised to be applicable. In order to avoid confusion and too many edits in the conditions, staff proposes to delete the approved conditions of certification **AQ-1** through **AQ-43** for the licensed HBEP completely and recommends the inclusion of the SCAQMD's new conditions as new conditions of certification **AQ-1** through **AQ-66** for the Amended HBEP. These changes incorporate the conditions of certification consistent in the current SCAQMD Determination of Compliance. Staff understands that **AQ-1** (SCAQMD condition F2.1) and **AQ-2** (SCAQMD condition F52.1) include limits and requirements for the existing HBGS units that are not jurisdictional to the Energy Commission. However, staff incorporated those limits and requirements for the non-jurisdictional units to make sure the amended facility complies with LORS during the transitional period before the existing units are retired and new units become available.

For completeness, all Air Quality conditions of certification are shown, both those that need changes and those that do not change. ~~Strikethrough~~ is used to indicate deleted language and **<u>bold/underline</u>** is used for new language. **Air Quality Table 24** shows the mapping of the Energy Commission conditions of certification (COCs) and SCAQMD condition numbering with staff proposed modifications and justification.

Air Quality Table 24
Mapping of Energy Commission and SCAQMD Condition Numbering with Proposed Modifications and Justification

Revised Energy Commission COCs Numbering	SCAQMD Numbering	Approved Energy Commission COCs Numbering	Staff Proposed Modifications and Justification
AQ-SC1 through **AQ-SC5**	Not Applicable	**AQ-SC1** through **AQ-SC5**	No change
AQ-SC6	Not Applicable	**AQ-SC6**	Revise according to the construction emissions and impacts for the Amended HBEP.
AQ-SC7, **AQ-SC8**	Not Applicable	**AQ-SC7**, **AQ-SC8**	No change

Revised Energy Commission COCs Numbering	SCAQMD Numbering	Approved Energy Commission COCs Numbering	Staff Proposed Modifications and Justification
AQ-SC9	Not Applicable	None	New. Staff proposes this new condition to ensure that the emissions of the auxiliary boiler and the oil/water separators would be mitigated with the quantity of SCAQMD offsets recommended by the SCAQMD and Energy Commission staff and to ensure agency consultation if substitutions are made to the credits.
AQ-1	F2.1	None	New
AQ-2	F52.1	None	New
AQ-3	F52.2	None	New
AQ-4	A63.6	None	New
AQ-5	A63.7	None	New
AQ-6	A63.8	None	New
AQ-7	A63.9	None	New
AQ-8	A63.10	None	New
AQ-9	A99.4	None	New
AQ-10	A99.5	None	New
AQ-11	A195.6	None	New
AQ-12	A195.7	None	New
AQ-13	A195.8	None	New
AQ-14	A195.9	None	New
AQ-15	A195.10	None	New
AQ-16	A195.11	None	New
AQ-17	A195.12	None	New
AQ-18	A195.13	None	New
AQ-19	A195.14	None	New
AQ-20	A327.1	None	New
AQ-21	B61.1	None	New
AQ-22	C1.7	None	New
AQ-23	C1.8	None	New
AQ-24	C1.9	None	New
AQ-25	C1.10	None	New
AQ-26	C1.11	None	New
AQ-27	C1.12	None	New
AQ-28	C1.13	None	New
AQ-29	C1.14	None	New
AQ-30	C157.1	None	New
AQ-31	D12.7	None	New

Revised Energy Commission COCs Numbering	SCAQMD Numbering	Approved Energy Commission COCs Numbering	Staff Proposed Modifications and Justification
AQ-32	D12.8	None	New
AQ-33	D12.9	None	New
AQ-34	D12.10	None	New
AQ-35	D12.11	None	New
AQ-36	D12.12	None	New
AQ-37	D12.13	None	New
AQ-38	D12.14	None	New
AQ-39	D12.15	None	New
AQ-40	D12.16	None	New
AQ-41	D29.5	None	New
AQ-42	D29.6	None	New
AQ-43	D29.7	None	New
AQ-44	D29.8	None	New
AQ-45	D29.9	None	New
AQ-46	D82.3	None	New
AQ-47	D82.4	None	New
AQ-48	D82.5	None	New
AQ-49	E144.1	None	New
AQ-50	E193.3	None	New
AQ-51	E193.4	None	New
AQ-52	E193.5	None	New
AQ-53	E193.6	None	New
AQ-54	E193.7	None	New
AQ-55	E193.8	None	New
AQ-56	E448.1	None	New
AQ-57	E448.2	None	New
AQ-58	E448.3	None	New
AQ-59	I297.1	None	New
AQ-60	I297.2	None	New
AQ-61	I297.3	None	New
AQ-62	I298.1	None	New
AQ-63	I298.2	None	New
AQ-64	I298.3	None	New
AQ-65	K40.3	None	New
AQ-66	K67.5	None	New

Revised Energy Commission COCs Numbering	SCAQMD Numbering	Approved Energy Commission COCs Numbering	Staff Proposed Modifications and Justification
None	None	**AQ-1** through **AQ-43**	Delete. Staff proposes to delete the approved COCs **AQ-1** through **AQ-43** for the licensed HBEP because most of them don't apply to the Amended HBEP or need to be substantially revised to be applicable.
None	F9.1, F14.1, F16.1, F18.1, and F24.1	None	These SCAQMD conditions do not apply to the Amended HBEP project. Therefore, staff does not propose to add them as new COCs.

STAFF-RECOMMENDED CONDITIONS OF CERTIFICATION

Staff proposes the following conditions of certification (identified as the **AQ-SCx** series of conditions) to provide CEQA mitigation for this project.

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 duration of project site 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 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 may be replaced only after compliance with the selection process outlined below. 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 that 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 will 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

Project owner shall implement the following control measures to mitigate for any increases in regional criteria pollutants during construction, including fugitive dust.

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) mitigation measures for 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 deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

A. The main access roads through the facility to the power block areas will be 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.) will be paved prior to taking initial deliveries.

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 ARB 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 disturbed areas in the project construction site 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 condition of certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

C. No vehicle shall exceed 10 miles per hour on unpaved areas within the construction site, 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. The construction site entrances shall be posted with visible speed limit signs.

E. Wheel washers shall be installed for all exiting trucks and equipment, or wheels shall be inspected and washed (as necessary) to remove accumulated dirt prior to leaving the site.

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

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

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

I. Sandbags or other erosion control measures shall be installed consistent with the requirements of the Storm Water Pollution Prevention Plan (SWPPP).

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

K. At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept as needed (less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or run-off resulting from the construction site activities is visible on the public paved roadways. The use of dry rotary brushes is expressly prohibited except where preceded or accompanied by sufficient wetting to limit the visible dust emissions. Use of blower devices is expressly forbidden.

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

M. When bulk materials are transported offsite, all materials that have the 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. 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 the CPM a Monthly Compliance Report to include the following to demonstrate control of fugitive dust emissions:

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

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

C. Any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement

The AQCMM or an AQCMM delegate shall monitor all 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 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 will 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 to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown activity. The owner/ operator may appeal to the CPM any directive from the AQCMM or delegate to shut down an activity, provided that the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

<u>Verification:</u> 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 air quality-related 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 Engine Control

The AQCMM shall submit to the CPM, in the Monthly Compliance Report, a table that demonstrates compliance with the AQCMP mitigation measures for purposes of controlling diesel construction-related combustion emissions. Any deviation from the AQCMP mitigation measures requires prior CPM notification and approval.

All off-road diesel construction equipment 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 (ARB's) Regulation for In-Use Off-Road Diesel Fleets and shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**. The AQCMP measures shall include the following, with the lowest-emitting engine chosen in each case, as available:

A. All off-road vehicles with compression ignition engines shall comply with the California Air Resources Board's (ARB's)Regulation for In- Use Off-Road Diesel Fleets (California Code of Regulation Title 13, Article 4.8, Chapter 9, §2449 et. seq.).

B. To meet the highest level of emissions reduction available for the engine family of the equipment, each piece of diesel-powered equipment shall be powered by a Tier 4 engine (without add-on controls) or Tier 4i engine (without ad-on controls), or a Tier 3 engine with a post-combustion retrofit device verified by the ARB or the US EPA. For PM, the retrofit device shall be a particulate filter if verified, or a flow-through filter, or at least an oxidation catalyst. For NOx, the device shall meet the latest Mark level verified to be available.

C. For diesel powered equipment where the requirements of Part "b" cannot be met, the equipment shall be equipped with a Tier 3 engine without retrofit control devices or with a Tier 2 or lower Tier engine using retrofit controls verified by ARB or 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 will employ electric motors when feasible.

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

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

Verification: The AQCMM shall include in the MCR the following to demonstrate control of diesel construction-related emissions:

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

B. A 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” or Part “c” requirements. 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 Construction Particulate Matter Mitigation Plan

The project owner shall prepare and implement a Construction Particulate Matter Mitigation Plan (CPMMP) that details the steps to be taken and the reporting requirements necessary to provide the equivalent of at least ~~8.26~~ **2.17** lbs/day PM10 and ~~0.79~~ **0.17** lbs/day PM2.5 of emissions reductions during the construction phase of the project. Construction emission reduction measures can include: localized street sweepers or programs; local ban of leaf blowing or blowers; sodding of local parks or playfields; fireplace or woodstove replacements; offsets or emission reduction credits; or other measures that can provide local emission reductions coincident with construction emissions.

Verification: At least 90 days prior to the start of any ground disturbance, the project owner shall submit the CPMMP to the CPM for review and approval. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. The CPMMP must be approved by the CPM before the start of ground disturbance. During construction the project owner shall provide the records of the CPMMP in the Monthly Compliance Report.

AQ-SC7 Permit-to-Construct (PTC) and Permit-to-Operate (PTO)

The project owner shall provide the CPM copies of all district issued Permit-to-Construct (PTC) and Permit-to-Operate (PTO) documents for the facility. The project owner shall submit an amendment request 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 PTC, PTO, and proposed air permit modifications 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.

AQ-SC8 Quarterly Operation Reports

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 the conditions of certification herein. The Quarterly Operation Report shall specifically note or highlight incidences of noncompliance.

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

AQ-SC9 The project owner shall provide emission reductions in the form of offsets or emission reduction credits (ERCs) in the quantities of at least 4 lbs/day of VOC and 5 lbs/day of PM10 emissions for the auxiliary boiler and 1 lb/day of VOC emissions for the oil/water separators. The project owner shall demonstrate that the reductions are provided in the form required by the South Coast Air Quality Management District (District).

The project owner shall provide an ERC list and surrender the ERCs as required by the District. The project owner shall request CPM approval for any substitutions, modifications, or additions to the ERCs.

The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, and that the requested change(s) will not cause the project to result in a significant environmental impact. The District must also confirm that each requested change is consistent with applicable federal and state laws and regulations.

Verification: The project owner shall submit to the CPM records showing that the project's offset requirements have been met prior to initiating construction. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and Energy Commission docket. The CPM shall maintain an updated list of approved ERCs for the project.

DISTRICT ~~FINAL DETERMINATION OF COMPLIANCE~~ CONDITIONS

The following SCAQMD conditions (**AQ-1** to **AQ-~~43~~66**) apply to **various units as identified where needed** ~~each unit of equipment and the proposed HBEP facility as a whole.~~

FACILITY CONDITIONS

AQ-1 The project owner shall limit emissions from this facility as follows:

CONTAMINANT	EMISSIONS LIMIT
PM	Less than 100 TONS IN ANY ONE YEAR

For purposes of this condition, the PM shall be defined as particulate matter with aerodynamic diameter of 2.5 microns or less.

For purposes of demonstrating compliance with the 100 tons per year limit the project owner shall sum the PM2.5 emissions for each of the sources at this facility by calculating a 12 month rolling average as follows:

Using the calendar monthly fuel use data and following emission factors for each combined cycle turbine PM2.5 = 3.94 lbs/mmcf., for each simple cycle turbine PM2.5 = 7.43 lbs/mmcf, for the auxiliary boiler PM2.5 = 7.54 lbs/mmcf, for Boiler 1 PM2.5 = 1.86 lbs/mmcf, for Boiler 2 PM2.5 = 2.1 lbs/mmcf. For each emergency engine using the rated hp and the calendar monthly hourly usage data and the following emission factor PM2.5 = 0.38 gr/bhp-hr.

The project owner may apply to change the factors, via permit application, once a different value is demonstrated, subject to SCAQMD review of testing procedures and protocols.

The project owner shall submit written reports of the monthly PM2.5 compliance demonstrations required by this condition. The report submittal shall be included with the semi annual Title V report as required under Rule 3004(a)(4)(f). Records of the monthly PM2.5 compliance demonstrations shall be maintained on site for at least five years and made available upon SCAQMD request.

Verification: The project owner shall submit to the CPM and the District the facility annual operating and emissions data demonstrating compliance with this condition as part of the fourth quarter's Quarterly Operation Report (AQ-SC8).

AQ-2 This facility is subject to the applicable requirements of the following rules or regulation(s):

The facility shall submit a detailed retirement plan for the permanent shutdown of Huntington Beach (HB) Boilers 1 and 2 and Redondo Beach (RB) Boiler 7 describing in detail the steps and schedule that will be taken to render the boilers permanently inoperable. The retirement plan shall be submitted to SCAQMD within 60 days after the Permits to Construct are issued for gas turbines CCTG 1, CCTG 2, SCTG 1, and SCTG 2.

AES shall not commence any construction of HB Boilers 1 and 2 and RB Boiler 7 repowering project equipment including gas turbines CCTG 1, CCTG 2, SCTG 1, SCTG 2, Auxiliary Boiler, ammonia storage tanks, or the oil water separators, unless the retirement plan is approved in writing by SCAQMD. If SCAQMD notifies AES that the plan is not approvable, AES shall submit a revised plan addressing SCAQMD's concerns within 30 days.

Within 30 calendar days of actual shutdown, or by no later than November 1, 2019, AES shall provide SCAQMD with a notarized statement that HB Beach Boiler 1 and RB Boiler 7 are permanently shutdown and that any restart or operation of the units shall require new Permits to Construct and be subject to all requirements of non-attainment new source review and the prevention of significant deterioration program.

Within 30 calendar days of actual shutdown, or by no later than December 31, 2020, AES shall provide SCAQMD with a notarized statement that HB Beach Boiler 2 is permanently shutdown and that any restart or operation of the unit shall require a new Permit to Construct and be subject to all requirements of non-attainment new source review and the prevention of significant deterioration program.

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of HB Boiler 1 and RB Boiler 7, or advise SCAQMD as soon practicable should AES undertake permanent shutdown prior to November 1, 2019.

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of HB Boiler 2, or advise SCAQMD as soon practicable should AES undertake permanent shutdown prior to December 31, 2020.

AES shall cease operation of HB Boiler 1 within 90 calendar days of the first fire of either CCTG 1 or CCTG 2, whichever is earlier. AES shall cease operation of HB Boiler 2 within 90 calendar days of the first fire of either SCTG 1 or SCTG 2, whichever is earlier. AES shall cease operation of RB Boiler 7 prior to the first fire of either CCTG 1 or CCTG 2, whichever is earlier.

At least 6 months prior to November 1, 2019, AES may submit a permit modification application requesting the permission to shutdown a combination of boilers other than HB Boiler 1, HB Boiler 2, and RB Boiler 7 to offset the increases for this project. The other boilers must be located at AES facilities Huntington Beach GS, Redondo Beach GS, or Alamitos GS, and approval of the application must be received prior to any changes being made to the shutdowns outlined in this condition.

Verification: The project owner shall submit the retirement plan and any modifications to the plan to the CPM within five working days of its submittal either by: 1) the project owner to District, or 2) receipt of proposed modifications from District. The project owner shall make site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-3 This facility is subject to the applicable requirements of the following rules or regulation(s):

For all circuit breakers at the facility utilizing SF_6, the project owner shall install, operate, and maintain enclosed-pressure SF_6 circuit breakers with a maximum annual leak rate of 0.5 percent by weight. The circuit breakers shall be equipped with a 10 percent by weight leak detection system. The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and all records of calibrations shall be maintained on site.

The total CO_2e emissions from all circuit breakers shall not exceed 71.8 tons per calendar year.

The project owner shall calculate the SF_6 emissions due to leakage from the circuit breakers by using the mass balance in equation DD-1 at 40 CFR Part 98, Subpart DD on an annual basis. Records of such calculations shall be maintained on site.

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

DEVICE CONDITIONS

A. Emission Limits

AQ-4 The project owner shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 3,090 LBS IN ANY ONE MONTH
CO	Less than or equal to 99,076 LBS IN ANY ONE MONTH
VOC	Less than or equal to 14,109 LBS IN ANY ONE MONTH

The above limits apply during commissioning. The above limits apply to each turbine.

The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 10.16 lbs/mmcf, PM10: 5.86 lbs/mmcf, and CO: 70.09 lbs/mmcf.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-5 The project owner shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 6,324 LBS IN ANY ONE MONTH
CO	Less than or equal to 26,440 LBS IN ANY ONE MONTH
VOC	Less than or equal to 7,611 LBS IN ANY ONE MONTH

The above limits apply after the equipment is commissioned. The above limits apply to each turbine.

The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 2.66 lbs/mmcf, PM10: 3.94 lbs/mmcf.

The project owner shall calculate compliance with the emission limits for CO after the CO CEMS certification based upon readings from the SCAQMD certified CEMS.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-6 The project owner shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 4,643 LBS IN ANY ONE MONTH
CO	Less than or equal to 8,273 LBS IN ANY ONE MONTH
VOC	Less than or equal to 1,972 LBS IN ANY ONE MONTH

The above limits apply after the equipment is commissioned. The above limits apply to each turbine.

The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 2.74 lbs/mmcf, PM10: 7.43 lbs/mmcf.

The project owner shall calculate compliance with the emission limits for CO after the CO CEMS certification based upon readings from the SCAQMD certified CEMS.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-7 The project owner shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 1,747 LBS IN ANY ONE MONTH
CO	Less than or equal to 25,449 LBS IN ANY ONE MONTH
VOC	Less than or equal to 836 LBS IN ANY ONE MONTH

The above limits apply during commissioning. The above limits apply to each turbine.

The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 3.67 lbs/mmcf, PM10: 7.67 lbs/mmcf, and CO: 111.76 lbs/mmcf.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-8 The project owner shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 120 LBS IN ANY ONE MONTH
CO	Less than or equal to 650 LBS IN ANY ONE MONTH
VOC	Less than or equal to 87 LBS IN ANY ONE MONTH

The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 5.47 lbs/mmcf, PM10: 7.54 lbs/mmcf, CO: 41.9 lbs/mmcf.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-9 The 19.09 LBS/MMSCF NOx emission limit(s) shall only apply during the first year of operation prior to CEMS certification for reporting NOx emissions.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-10 The 25.11 LBS/MMSCF NOx emission limit(s) shall only apply during the first year of operation prior to CEMS certification for reporting NOx emissions.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-11 The 2.0 PPMV NOx emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-12 The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-13 The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

The combined-cycle turbines and simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-14 The 1,000 LBS/MW-HR CO_2 emission limit(s) is averaged over a rolling 12 operating month basis. The limit shall only apply if the turbine supplies more than 1,519,500 MWh net electrical output to a utility distribution system over a rolling 12 operating month basis and a 3 year rolling average basis.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-15 The 5.0 ppmv NH_3 emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry basis. The project owner shall calculate and continuously record the NH_3 slip concentration using the following:

NH_3 (ppmv) = [a–b*(c*1.2)/1E+06]*1E+06/b

where,

a = NH_3 injection rate (lbs/hr)/17(lb/lb-mol)

b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)

c = change in measured NOx across the SCR (ppmvd at 15 percent O_2)

The project owner shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months. The NOx analyzer shall be installed and operated within 90 days of initial start-up.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.

The project owner shall use the above described method or another alternative method approved by the Executive Officer.

The SCRs for the combined-cycle turbines, the simple-cycle turbines, and the auxiliary boiler[1] are subject to this condition.

Verification: The project owner shall include exceedances of the hourly ammonia slip limit as part of the Quarterly Operation Reports (AQ-SC8). Exceedances of the ammonia limit shall be reported as prescribed herein. Chronic exceedances of the ammonia slip limit shall be identified by the project owner and confirmed by the CPM within 60 days of the fourth quarter Quarterly Operation Report (AQ-SC8) being submitted to the CPM. If a chronic exceedance is identified and confirmed, the project owner shall work in conjunction with the CPM to develop a reasonable compliance plan to investigate and redress the chronic exceedance of the ammonia slip limit within 60 days of the above confirmation. The project owner shall include all calibration results performed as part of Quarterly Operation Reports (AQ-SC8).

AQ-16 The 2.5 PPMV NOx emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-17 The 4.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

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[1] Staff believes that the emissions for the auxiliary boiler should be corrected to 3 percent O_2 instead of 15 percent O_2. A new condition may be added for the auxiliary boiler in the Final Determination of Compliance (FDOC) and Final Staff Assessment (FSA).

AQ-18 The 5.0 PPMV NOx emission limit(s) is averaged over 60 minutes at 3 percent O_2, dry. This limit shall not apply during boiler start ups.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-19 The 50.0 PPMV CO emission limit(s) is averaged over 60 minutes at 3 percent O_2, dry. This limit shall not apply during boiler start ups.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-20 For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

B. Material/Fuel Type Limits

AQ-21 The project owner shall not use natural gas containing the following specified compounds:

Compound	grain per 100 scf
H_2S greater than	0.25

This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H_2S.

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit fuel usage records and calculations required to demonstrate compliance with this condition as part of the Quarterly Operational Reports (AQ-SC8).

C. Throughput or Operating Parameter Limits

AQ-22 The project owner shall limit the number of start-ups to no more than 62 in any one calendar month.

The number of cold start ups shall not exceed 15 per month, the number of warm start ups shall not exceed 12 per month, and the number of hot start ups shall not exceed 35 per month. Additionally, the number of cold start ups shall not exceed 80 per year, the number of warm start ups shall not exceed 88 per year, and the number of hot start ups shall not exceed 332 per year.

For the purposes of this condition: A cold start up is defined as a start up which occurs after the steam turbine has been shutdown for 48 hours or more. A cold start up shall not exceed 60 minutes. Emissions during the 60 minutes that includes a cold start up shall not exceed the following: NOx - 61 lbs., CO – 325 lbs., VOC – 36 lbs.

A warm start up is defined as a start up which occurs after the steam turbine has been shutdown for 9 – 48 hours. A warm start up shall not exceed 30 minutes. Emissions during the 30 minutes that includes a warm start up shall not exceed the following: NOx - 17 lbs., CO – 137 lbs., VOC –25 lbs.

A hot start up is defined as a start up which occurs after the steam turbine has been shutdown for less than 9 hours. A hot start up shall not exceed 30 minutes. Emissions during the 30 minutes that includes a hot start up shall not exceed the following: NOx - 17 lbs., CO – 137 lbs., VOC – 25 lbs.

The beginning of a start up occurs at initial fire in the combustor and the end of start up occurs when the BACT levels are achieved. If during start up the process is aborted the process will count as one start up.

The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-23 The project owner shall limit the number of shut-downs to no more than 62 in any one calendar month.

Additionally, the number of shutdowns shall not exceed 500 per year.

Shutdown time shall not exceed 30 minutes per shutdown. Emissions during the 30 minutes that includes a shutdown shall not exceed the following: NOx – 10 lbs., CO – 133 lbs., VOC – 32 lbs.

The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-24 The project owner shall limit the operating time to no more than 6640 hour(s) in any one calendar year.

The limit includes baseload operation as well as start ups and shutdowns. The limit does not apply to the calendar year in which the units are commissioned.

Combined Cycle Turbines No. 1 and No. 2 shall not simultaneously operate at minimum load for more than 20 consecutive hours (approximately 44 percent of full load rating).

The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-25 The project owner shall limit the number of start-ups to no more than 62 in any one calendar month.

Additionally, the number of start ups shall not exceed 350 per year.

A start up shall not exceed 30 minutes. Emissions during the 30 minutes that includes a start up shall not exceed the following: NOx – 16.6 lbs., CO – 15.4 lbs., VOC – 2.8 lbs.

The beginning of a start up occurs at initial fire in the combustor and the end of start up occurs when the BACT levels are achieved. If during start up the process is aborted the process will count as one start up.

The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-26 The project owner shall limit the number of shutdowns to no more than 62 in any one calendar month.

Additionally, the number of shutdowns shall not exceed 350 per year.

Shutdown time shall not exceed 13 minutes per shutdown. Emissions during the 13 minutes that includes a shutdown shall not exceed the following: NOx – 3.12 lbs., CO – 28.1 lbs., VOC – 3.06 lbs.

The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-27 The project owner shall limit the operating time to no more than 2001 hour(s) in any one calendar year.

The limit includes baseload operation as well as start ups and shutdowns. The limit does not apply to the calendar year in which the units are commissioned.

The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-28 The project owner shall limit the number of start-ups to no more than 10 in any one calendar month.

The number of cold start ups shall not exceed 2 per month, the number of warm start ups shall not exceed 4 per month, and the number of hot start ups shall not exceed 4 per month. Additionally, the number of cold start ups shall not exceed 24 per year, the number of warm start ups shall not exceed 48 per year, and the number of hot start ups shall not exceed 48 per year.

For the purposes of this condition: A cold start up is defined as a start up which occurs after the boiler shutdown for 48 hours or more. A cold start up shall not exceed 170 minutes. Emissions during the170 minutes that includes a cold start up shall not exceed the following: NOx – 4.22 lbs., CO – 4.34 lbs., VOC – 1.05 lbs.

A warm start up is defined as a start up which occurs after the boiler has been shutdown for 9 – 48 hours. A warm start up shall not exceed 85 minutes. Emissions during the 85 minutes that includes a warm start up shall not exceed the following: NOx – 2.11 lbs., CO – 2.17 lbs., VOC – 0.52 lbs.

A hot start up is defined as a start up which occurs after the boiler has been shutdown for less than 9 hours. A hot start up shall not exceed 25 minutes. Emissions during the 25 minutes that includes a hot start up shall not exceed the following: NOx – 0.62 lbs., CO – 0.64 lbs., VOC – 0.15 lbs.

The beginning of a start up occurs at initial fire in the burner and the end of start up occurs when the BACT levels are achieved. If during start up the process is aborted the process will count as one start up.

The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-29 The project owner shall limit the heat input to no more than 189,155 MM Btu in any one calendar year.

The limit includes normal operation as well as start ups and shutdowns. The heat input shall be calculated using the fuel use data and a natural gas HHV of 1,050 btu/mmcf.

The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit fuel usage records and calculations required to demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-30 The project owner shall install and maintain a pressure relief valve set at 50 psig.

The ammonia storage tanks are subject to this condition.

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

D. Monitoring/Testing Requirements

AQ-31 The project owner shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The project owner shall also install and maintain a device to continuously record the ammonia flow rate. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The injected ammonia rate shall be maintained within 44.0 lbs/hr and 242.0 lbs/hr except during start ups and shutdowns.

The SCRs for the combined-cycle turbines are subject to this condition.

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

AQ-32 The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The project owner shall also install and maintain a device to continuously record the exhaust temperature. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The exhaust temp at the inlet of the SCR shall be maintained between 570-692 deg F except during start up and shutdowns.

The SCRs for the combined-cycle turbines are subject to this condition.

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

AQ-33 The project owner shall install and maintain a(n) differential pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The project owner shall also install and maintain a device to continuously record the differential pressure. Continuous monitoring shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month. The pressure gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The differential pressure shall not exceed 1.6 inches water column (WC).

The SCRs for the combined-cycle turbines are subject to this condition.

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

AQ-34 The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the CO Catalyst.

The project owner shall also install and maintain a device to continuously record the exhaust temperature. Continuously record shall be defined as recording at least once every hour and shall be calculated based on the average of the continuous monitoring for that hour. The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The exhaust temp at the CO Catalyst inlet shall be maintained at a minimum of 570 deg F except during start up and shutdowns.

The CO Catalysts for the combined-cycle turbines and the simple-cycle turbines are subject to this condition.

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

AQ-35 The project owner shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The project owner shall also install and maintain a device to continuously record the ammonia flow rate. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The injected ammonia rate shall be maintained within 110 lbs/hr and 180 lbs/hr except during start ups and shutdowns.

The SCRs for the simple-cycle turbines are subject to this condition.

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

AQ-36 The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The project owner shall also install and maintain a device to continuously record the exhaust temperature. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The exhaust temp at the inlet of the SCR shall be maintained between 500-870 deg F except during start up and shutdowns.

The SCRs for the simple-cycle turbines are subject to this condition.

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

AQ-37 The project owner shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The project owner shall also install and maintain a device to continuously record the differential pressure. Continuous monitoring shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month. The pressure gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The differential pressure shall not exceed 3.0 inches water column (WC).

The SCRs for the simple-cycle turbines are subject to this condition.

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

AQ-38 The project owner shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The project owner shall also install and maintain a device to continuously record the ammonia flow rate. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The injected ammonia rate shall be maintained within 1.0 lbs/hr and 3.9 lbs/hr except during start ups and shutdowns.

The SCR for the auxiliary boiler is subject to this condition.

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

AQ-39 The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The project owner shall also install and maintain a device to continuously record the exhaust temperature. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The exhaust temperature shall be maintained between 406-636 deg F except during start ups and shutdowns.

The SCR for the auxiliary boiler is subject to this condition.

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

AQ-40 The project owner shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The project owner shall also install and maintain a device to continuously record the differential pressure. Continuous monitoring shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month. The pressure gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The differential pressure shall not exceed 2.0 inches water column (WC).

The SCR for the auxiliary boiler is subject to this condition.

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

AQ-41 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOx emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	District Lab method 307-91	District-approved averaging time	Fuel Sample
VOC emissions	District method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA method 201A/District method 5.1	District-approved averaging time	Outlet of the SCR serving this equipment
PM2.5 emissions	EPA method 201A and 202	District-approved averaging time	Outlet of the SCR serving this equipment
NH_3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted after SCAQMD approval of the source test protocol, but no later than 180 days after initial start-up. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW net and MW gross.

The test shall be conducted in accordance with an SCAQMD approved protocol. The protocol shall be submitted to the SCAQMD engineer no later than 45 days before the proposed test date and shall be approved by the SCAQMD before the test commences. The protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at 3 load conditions, including within 5 percent of maximum, within 5 percent of minimum, and one intermediate load.

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by ARB and SCAQMD may be the following:

a) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and

c) Analysis of Summa canisters per unmodified EPA Method TO-12 (with pre-concentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv ROG calculated as carbon set by ARB for natural gas fired turbines.

For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, ARB, and SCAQMD.

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit the proposed protocol for the initial source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test date and time.

AQ-42 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NH_3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit.

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit the proposed protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 10 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-43 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
SOx emissions	District Lab method 307-91	District-approved averaging time	Fuel Sample
VOC emissions	District method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA method 201A/District method 5.1	District-approved averaging time	Outlet of the SCR serving this equipment

The test shall be conducted at least once every three years.

The test shall be conducted and the results submitted to the SCAQMD within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when this equipment is operating at 100 percent of maximum heat input.

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by ARB and SCAQMD may be the following:

a) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and

c) Analysis of Summa canisters per unmodified EPA Method TO-12 (with pre-concentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv ROG calculated as carbon set by ARB for natural gas fired turbines.

For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, ARB, and SCAQMD.

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit the proposed protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 10 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-44 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOx emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District method 5.1	District-approved averaging time	Outlet of the SCR serving this equipment
NH_3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment
PM2.5 emissions	EPA method 201A and 202	District-approved averaging time	Outlet of the SCR serving this equipment

The test shall be conducted after SCAQMD approval of the source test protocol, but no later than 180 days after initial start-up. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when this equipment is operating at 100 percent, 50 percent, and minimum load.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), and the flue gas flow rate.

The test shall be conducted in accordance with an SCAQMD approved test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 45 days before the proposed test date and shall be approved by the SCAQMD before the test commences.

The test protocol shall include the proposed operating conditions of the boiler during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit the proposed protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 10 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-45 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
CO emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted at least once every three years, or in accordance with the schedule specified in Rule 1146.

The test shall be conducted and the results submitted to the SCAQMD within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when this equipment is operating at 100 percent of maximum load.

In addition to the Method 100.1 test, the project owner shall also perform periodic CO emissions tests on the boiler with a portable analyzer in accordance with the schedule and specifications outlined in Rule 1146.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit the proposed protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 10 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-46 The project owner shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine, in accordance with approved SCAQMD Rule 218 CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.

The CEMS shall be installed and operated to measure the CO concentration over a 15 minute averaging time period.

The CEMS shall convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9%-%O_2 d)]*[(Qg*HHV)/10E6], where

1. K = $7.267*10^{-8}$ (lbs/scf)/ppm

2. Cco = Average of 4 consecutive 15 min. average CO concentrations, ppm

3. Fd = 8710 dscf/MMBTU natural gas

4. %O_2, d = Hourly average % by volume O_2 dry, corresponding to Cco

5. Qg = Fuel gas usage during the hour, scf/hr

6. HHV = Gross high heating value of the fuel gas, BTU/scf

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.

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

AQ-47 The project owner shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine, in accordance with approved SCAQMD REG XX CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start up and the provisional certification date of the CEMS, the operator shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.

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

AQ-48 The project owner shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 3 percent[2] oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the boiler, in accordance with approved SCAQMD REG XX CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the combined cycle turbine commissioning and boiler construction period. During the interim period between the initial start up and the provisional certification date of the CEMS, the project owner shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).

The auxiliary boiler is subject to this condition.

[2] Staff believes that the emissions for the auxiliary boiler should be corrected to 3 percent O_2 instead of 15 percent O_2 shown in SCAMQD condition D82.5. The value needs to be confirmed by the SCAQMD and may change in the Final Determination of Compliance (FDOC) and Final Staff Assessment (FSA).

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

E. Equipment Operation/Construction Requirements

AQ-49 The project owner shall vent this equipment, during filling, only to the vessel from which it is being filled.

The ammonia storage tanks are subject to this condition.

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-50 The project owner shall install this equipment according to the following requirements:

Construction shall commence within 12 months of the date of the permit to construct unless the permit is extended, but in no case should the start of construction exceed 18 months from the date of the permit to construct. Construction shall not be discontinued for a period of 18 months or more.

The combined-cycle turbines, the simple-cycle turbines, the auxiliary boiler and their corresponding SCRs, CO Catalysts, and ammonia storage tanks are subject to this condition.[3]

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

AQ-51 The project owner shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

The combined-cycle turbines, the simple-cycle turbines, the auxiliary boiler and their corresponding SCRs, CO Catalysts, and ammonia storage tanks are subject to this condition.

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

AQ-52 The project owner shall install this equipment according to the following requirements:

[3] The corresponding SCAQMD condition E193.3 shows that only the turbines are subject to this condition. Staff believes that all equipment (including turbines, auxiliary boiler, SCRs, CO catalysts, and ammonia storage tanks) of the Amended HBEP should be subject to this condition. This needs to be confirmed by the SCAQMD and may change in the Final Determination of Compliance (FDOC) and Final Staff Assessment (FSA).

Total commissioning hours shall not exceed 996 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 216 hours of operation for each turbine.

The project owner shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning.

The project owner shall provide SCAQMD with written notification of the initial start up date. Written records of commissioning, start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall submit records to demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-53 The project owner shall upon completion of construction, operate and maintain this equipment according to the following specifications:

The project owner shall record the total net power generated in a calendar month in megawatt-hours.

The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

$CO_2 = 60.009 * FF$

Where, CO_2 is in tons and FF is the monthly fuel usage in millions standard cubic feet.

The project owner shall calculate and record the CO_2 emissions in pounds per net megawatt-hour on a 12-month rolling average. The CO_2 emissions from this equipment shall not exceed 873,035 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed 967.6 pounds per net MW-hour.

The project owner shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.

The combined-cycle turbines are subject to this condition.

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

AQ-54 The project owner shall install this equipment according to the following requirements:

Total commissioning hours shall not exceed 280 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 4 hours of operation for each turbine.

The project owner shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning.

The project owner shall provide SCAQMD with written notification of the initial start up date. Written records of commissioning, start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit records to demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8).

AQ-55 The project owner shall upon completion of construction, operate and maintain this equipment according to the following specifications:

The project owner shall record the total net power generated in a calendar month in megawatt-hours.

The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

$CO_2 = 60.009 * FF$

Where, CO_2 is in tons and FF is the monthly fuel usage in millions standard cubic feet.

The project owner shall calculate and record the CO_2 emissions in pounds per net megawatt-hour on a 12-month rolling average. The CO_2 emissions from this equipment shall not exceed 103,576 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed 1378.0 pounds per net MW-hour.

The project owner shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.

The simple-cycle turbines are subject to this condition.

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

AQ-56 The project owner shall comply with the following requirements:

The total electricity output on a gross basis from combined cycle turbines devices D115 and D124, and their common steam turbine shall not exceed 693.8 MW.

The gross electrical output shall be measured at the single generator serving each of the combined cycle turbines, and the single generator serving the common steam turbine. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15 minute averaging time period.

The project owner shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall report the maximum gross megawatts generated monthly to demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-57 The project owner shall comply with the following requirements:

The total electricity output on a gross basis from simple cycle turbines devices D133 and D139 shall not exceed 201.6 MW.

The gross electrical output shall be measured at the single generator serving each of the simple cycle turbines. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15 minute averaging time period.

The project owner shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall report the maximum gross megawatts generated monthly to demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-58 The project owner shall comply with the following requirements:

This equipment shall not supply more than 43 percent of its potential electrical output or more than 376,200 MWh net electrical output to a utility distribution system on a 12 operating month rolling average and a 3 year rolling average basis

The project owner shall record and maintain written records of the amount of electricity supplied to the utility distribution system expressed as a percentage of the total potential electrical output of the turbine and shall make the records available to the Executive Officer upon request.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

I. Administrative

AQ-59 This equipment shall not be operated unless the facility holds 147,093 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-60 This equipment shall not be operated unless the facility holds 26,970 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-61 This equipment shall not be operated unless the facility holds 1,313 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-62 This equipment shall not be operated unless the facility holds 14,803 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 9,960 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-63 This equipment shall not be operated unless the facility holds 1,660 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 1,201 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-64 This equipment shall not be operated unless the facility holds 382 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 382 pounds[4] of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The auxiliary boiler is subject to this condition.

[4] Staff believes that the SOx RTC holding requirement for the auxiliary boiler for any subsequent year after the first year of operation should be equal to the SOx RTC holding requirement for the first year of operation (382 pounds instead of 360 pounds), as shown in the PDOC calculations. The value needs to be confirmed by the SCAQMD and may change in the Final Determination of Compliance (FDOC) and Final Staff Assessment (FSA).

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

K. Record Keeping/Reporting

AQ-65 The project owner shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source tests required under conditions AQ-41, AQ-42, and AQ-43 are conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.[5]

Verification: The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-66 The project owner shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Commissioning hours and type of control and fuel use

Date, time, and duration of each start-up and shutdown, and the type of start up (cold, warm, or hot)

In addition to the requirements of a certified CEMS, natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification

Minute by minute data (NO_2 and O_2 concentration and fuel flow rate at a minimum) for each turbine start up and shutdown

[5] Staff believes that a similar condition should be added to require source test report for the auxiliary boiler, which needs to be confirmed by the SCAQMD and may change in the Final Determination of Compliance (FDOC) and Final Staff Assessment (FSA).

Total annual power output in MWh

The combined-cycle turbines and the simple-cycle turbines are subject to this condition.

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

~~**AQ-1** The project owner shall limit emissions from this facility as follows:~~

~~**CONTAMINANT**~~	~~**EMISSIONS LIMIT**~~
~~PM~~	~~Less than 100 TONS IN ANY ONE YEAR~~

~~For purposes of this condition, the PM shall be defined as particulate matter with aerodynamic diameter of 2.5 microns or less.~~

~~For purposes of demonstrating compliance with the 100 tons per year limit the project owner shall sum the PM2.5 emissions for each of the major sources at this facility by calculating a 12 month rolling average using the calendar monthly fuel use data and following emission factors for each turbine PM2.5 = 3.36 lbs/mmcf with no duct firing and PM2.5 = 5.22 lbs/mmcf with duct firing, for Boiler 1 PM2.5 = 1.86 lbs/mmscf, for Boiler 2 PM2.5 = 2.1 lbs/mmscf.~~

~~The project owner may apply to change the factors, via permit application, once a different value is demonstrated, subject to SCAQMD review of testing procedures and protocols.~~

~~The project owner shall submit written reports of the monthly PM2.5 compliance demonstrations required by this condition. The report submittal shall be included with the semiannual Title V report as required under Rule 3004(a)(4)(f). Records of the monthly PM2.5 compliance demonstrations shall be maintained on site for at least five years and made available upon SCAQMD request.~~

~~[Rule 1325, 40CFR 51, Appendix S]~~

~~**Verification:** The project owner shall submit to the CPM and the District the facility annual operating and emissions data demonstrating compliance with this condition as part of the fourth quarter's Quarterly Operation Report (**AQ-SC8**).~~

~~**AQ-2** This facility is subject to the applicable requirements of the following rules or regulations:~~

~~The facility shall submit a detailed retirement plan for the permanent shutdown of Huntington Beach (HB) Boilers 1 and 2 and Redondo Beach (RB) Boilers 6 and 8 describing in detail the steps and schedule that will be taken to render the boilers permanently inoperable. The retirement plan shall be submitted to SCAQMD within 60 days after the Permits to Construct for gas turbine Units 1A, 1B, 1C, 2A, 2B, and 2C are issued.~~

~~The retirement plan must be approved in writing by SCAQMD. AES shall not commence any construction of HB Boilers 1 and 2 and RB Boilers 6 and 8 repowering project equipment including gas turbines 1A, 1B, 1C, 2A, 2B, 2C, steam turbines 1 and 2, SCR/CO catalysts for gas turbines 1A, 1B, 1C, 2A, 2B, and 2C, or the oil water separator, before the retirement plan is approved in writing by SCAQMD. If SCAQMD notifies AES that the plan is not approvable, AES shall submit a revised plan addressing SCAQMD's concerns within 30 days.~~

~~Within 30 calendar days of actual shutdown, or by no later than December 31, 2018, AES shall provide SCAQMD with a notarized statement that HB Beach Boilers 1 and 2 and RB Boilers 6 and 8 are permanently shut down and that any restart or operation of the units shall require new Permits to Construct and be subject to all requirements of non-attainment new source review and the prevention of significant deterioration program.~~

~~AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of HB Boilers 1 and 2 and RB Boilers 6 and 8, or advise SCAQMD as soon practicable should AES undertake permanent shutdown prior to December 31, 2018.~~

~~AES shall cease operation of RB Boilers 6 and 8 within 90 calendar days of the first fire of Units 1A, 1B, or 1C, and AES shall cease operation of HB Boilers 1 and 2 within 90 calendar days of the first fire of Units 2A, 2B, or 2C.~~

~~Rule 1304 – Modeling and Offset Exemption]~~

~~Verification:~~ ~~The project owner shall submit the retirement plan and any modifications to the plan to the CPM within five working days of its submittal either by: 1) the project owner to district, or 2) receipt of proposed modifications from district. The project owner shall make site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~AQ-3~~ ~~This facility is subject to the applicable requirements of the following rules or regulations:~~

~~For all circuit breakers at the facility utilizing SF_6, the project owner shall install, operate, and maintain enclosed-pressure SF_6 circuit breakers with a maximum annual leak rate of 0.5 percent by weight. The circuit breakers shall be equipped with a 10 percent by weight leak detection system. The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and all records of calibrations shall be maintained on site.~~

~~The total CO2e emissions from all circuit breakers shall not exceed 6.8 tons per calendar year.~~

~~[Rule 1714]~~

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

~~**EACH GAS TURBINE**~~

~~**AQ-4** The project owner shall limit emission from this equipment as follows:~~

~~**CONTAMINANT**~~	~~**EMISSION LIMIT**~~
~~PM10~~	~~4,278.0 LBS IN ANY ONE MONTH~~
~~CO~~	~~12,776.2 LBS IN ANY ONE MONTH~~
~~VOC~~	~~7,487.2 LBS IN ANY ONE MONTH~~

~~The above limits apply after the equipment is commissioned. The above limits apply to each turbine.~~

~~The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 2.94 lbs/mmcf, PM10: 3.36 lbs/mmcf with no duct burner firing, 5.22 lbs/mmcf with duct burner firing.~~

~~The project owner may apply to change the factors, via permit application, once a different value is demonstrated, subject to SCAQMD review of testing procedures and protocols.~~

~~The project owner shall calculate compliance with the emission limits for CO after the CO CEMS certification based upon readings from the SCAQMD certified CEMS.~~

~~The project owner shall limit the annual firing hours for each turbine to 6370 hours including no more than 470 hours with duct firing (this does not include start up and shutdown hours)~~

~~[Rule 1303 – Offsets]~~

~~**Verification:** The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~**AQ-5** The project owner shall limit emission from this equipment as follows:~~

~~**CONTAMINANT**~~	~~**EMISSION LIMIT**~~
~~PM10~~	~~2,930 LBS IN ANY ONE MONTH~~
~~CO~~	~~112,882 LBS IN ANY ONE MONTH~~
~~VOC~~	~~14,121 LBS IN ANY ONE MONTH~~

~~The above limits apply during commissioning. The above limits apply to each turbine.~~

~~The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 21.74 lbs/mmcf, PM10: 4.51 lbs/mmcf, and CO: 173.80 lbs/mmcf.~~

~~**Verification:** The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~**AQ-6** The 12.75 LBS/MMCF NOx emission limits shall only apply during turbine operation prior to CEMS certification for reporting NOx emissions.~~

~~[Rule 2012]~~

~~**Verification:** The project owner shall demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-7** The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent~~ $\cancel{O_2}$~~, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.~~

~~[Rule 1703-PSD, Rule 2005]~~

~~**Verification:** The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-8** The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent~~ $\cancel{O_2}$~~, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.~~

~~[Rule 1703-PSD]~~

~~**Verification:** The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-9** The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent~~ $\cancel{O_2}$~~, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.~~

~~[Rule 1303(a) – BACT, Rule 1303(b)(1) – Modeling, Rule 1303(b)(2) - Offsets]~~

~~**Verification:** The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-10** The 1100 lbs/net MWH CO2 limit is averaged over 12 rolling months. This limit only applies if the capacity factor of the unit is equal to or exceeds 60% on an annual basis.~~

~~**Verification:** The project owner shall demonstrating compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~**AQ-11** For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.~~

~~[Rule 475]~~

~~**Verification:** The project owner shall demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~**AQ-12** The project owner shall not use natural gas containing the following specified compounds:~~

~~**Compound**~~	~~**Grains per 100 scf**~~
~~H_2S~~	~~Greater than 0.25~~

~~This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H_2S.~~

~~[Rule 1303(b) – Offset]~~

~~**Verification:** The project owner shall submit fuel usage records and calculations required to demonstrate compliance with this condition as part of the Quarterly Operational Reports (**AQ-SC8**).~~

~~**AQ-13** The project owner shall limit the number of startups to no more than 90 in any one calendar month.~~

~~The number of cold start ups shall not exceed 5 per month, the number of warm start ups shall not exceed 25 per month, and the number of hot start ups shall not exceed 60 per month.~~

~~For the purposes of this condition:~~

~~A cold start up is defined as a startup which occurs after the steam turbine has been shut down for 49 hours or more. A cold start up shall not exceed 90 minutes. Emissions from a cold start up shall not exceed the following: NOx - 29 lbs., CO – 116 lbs., VOC – 28 lbs.~~

~~A warm start up is defined as a startup which occurs after the steam turbine has been shut down for 9 – 49 hours. A warm start up shall not exceed 32.5 minutes. Emissions from a warm start up shall not exceed the following: NOx - 17 lbs., CO – 46 lbs., VOC – 21 lbs.~~

~~A hot start up is defined as a startup which occurs after the steam turbine has been shut down for less than 9 hours. A hot start up shall not exceed 32.5 minutes. Emissions from a hot start up shall not exceed the following: NOx - 17 lbs., CO – 34 lbs., VOC – 21 lbs.~~

~~The beginning of a start up occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. If during start up the process is aborted the process will count as one start up.~~

~~The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.~~

~~[Rule 2005]~~

~~**Verification:**~~ ~~The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~**AQ-14**~~ ~~The project owner shall limit the number of shutdowns to no more than 90 in any one calendar month.~~

~~Shutdown time shall not exceed 10 minutes per shutdown. Emissions from a shutdown shall not exceed the following: NOx - 9 lbs., CO – 46 lbs., VOC – 31 lbs.~~

~~The project owner shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.~~

~~[Rule 2005]~~

~~**Verification:**~~ ~~The project owner shall provide a table demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~**AQ-15**~~ ~~The project owner shall limit the power output of the plant to no more than 939 MWs. The 939 MW limit is based on the net power output.~~

~~The net electrical output shall be measured at the breaker of the transmission system interconnection point in the generation switchyard. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/-0.2 percent.~~

~~The net electrical output from each meter shall be recorded at the CEMS data acquisition system.~~

~~The project owner shall maintain records, for a minimum of five years, in a manner approved by the SCAQMD to demonstrate compliance with this condition.~~

~~[Rule 1304 - Modeling and Offset Exemption]~~

~~**Verification:** The project owner shall report the maximum net megawatts generated monthly to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~**AQ-16** The project owner shall limit the power output of the plant to no more than 972 MW gross.~~

~~The 972 MW limit is based on the gross power output.~~

~~The gross electrical output shall be measured at the each of the 8 generators.~~

~~The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/-0.2 percent.~~

~~The gross electrical output from generators shall be recorded at the CEMS data acquisition system.~~

~~The project owner shall maintain records, for a minimum of five years, in a manner approved by the SCAQMD to demonstrate compliance with this condition.~~

~~[Rule 1304 - Modeling and Offset Exemption]~~

~~**Verification:** The project owner shall report the maximum gross megawatts generated monthly to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.~~

~~**AQ-17** The project owner shall conduct source test(s) for the pollutant(s) identified below.~~

~~**Pollutant to be tested**~~	~~**Required Test Method(s)**~~	~~**Averaging Time**~~	~~**Test Location**~~
~~NOX emissions~~	~~District Method 100.1~~	~~1 hour~~	~~Outlet of the SCR~~
~~CO emissions~~	~~District Method 100.1~~	~~1 hour~~	~~Outlet of the SCR~~

~~**Pollutant to be tested**~~	~~**Required Test Method(s)**~~	~~**Averaging Time**~~	~~**Test Location**~~
~~SOX emissions~~	~~Approved District method~~	~~District approved averaging time~~	~~Fuel Sample~~
~~VOC emissions~~	~~Approved District method~~	~~1 hour~~	~~Outlet of the SCR~~
~~PM10 emissions~~	~~Approved District method~~	~~District approved averaging time~~	~~Outlet of the SCR~~
~~PM2.5~~	~~Approved District method~~	~~District approved averaging time~~	~~Outlet of the SCR~~
~~NH3 emissions~~	~~District method~~ ~~207.1 and 5.3 or EPA method 17~~	~~1 hour~~	~~Outlet of the SCR~~

~~The test shall be conducted after SCAQMD approval of the source test protocol, but no later than 180 days after initial start-up. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.~~

~~The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate in cubic feet per hour (CFH), the flue gas flow rate, and the turbine generating output in MW net and MW gross.~~

~~The test shall be conducted in accordance with an SCAQMD approved test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 45 days before the proposed test date and shall be approved by the SCAQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.~~

~~The test shall be conducted when this equipment is operating at loads of 100 and 70 percent without duct firing, and 100 percent with duct firing.~~

~~For natural gas fired turbines only, volatile organic compound (VOC) compliance shall be demonstrated as follows: a) stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) analysis of canisters are per EPA Method~~

~~TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F. The use of this alternative method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The results shall be reported with two significant digits.~~

~~[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703-PSD, Rule 2005]~~

~~**Verification:**~~ ~~The project owner shall submit the proposed protocol for the initial source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test date and time.~~

~~**AQ-18**~~ ~~The project owner shall conduct source test(s) for the pollutant(s) identified below.~~

~~**Pollutant to be tested**~~	~~**Required Test Method(s)**~~	~~**Averaging Time**~~	~~**Test Location**~~
~~NH_3 emissions~~	~~District method 207.1 and 5.3 or EPA method 17~~	~~1 hour~~	~~Outlet of the SCR~~

~~The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.~~

~~The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.~~

~~The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit~~

~~[Rule 1303(a)(1) – BACT]~~

~~**Verification:**~~ ~~The project owner shall submit the proposed protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 10 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.~~

~~**AQ-19**~~ ~~The project owner shall conduct source test(s) for the pollutant(s) identified below.~~

~~Pollutant to be tested~~	~~Required Test Method(s)~~	~~Averaging Time~~	~~Test Location~~
~~SOX emissions~~	~~Approved District method~~	~~District approved averaging time~~	~~Fuel Sample~~
~~VOC emissions~~	~~Approved District method~~	~~1 hour~~	~~Outlet of the SCR~~
~~PM10 emissions~~	~~Approved District method~~	~~District approved averaging time~~	~~Outlet of the SCR~~

~~The test shall be conducted at least once every three years.~~

~~The test shall be conducted and the results submitted to the SCAQMD within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.~~

~~The test shall be conducted when this equipment is operating at 100 percent of maximum heat input.~~

~~For natural gas fired turbines only, volatile organic compound (VOC) compliance shall be demonstrated as follows: a) stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.~~

~~The use of this alternative method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The results shall be reported with two significant digits.~~

~~The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emission limit.~~

~~[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 475]~~

~~**Verification:**~~ ~~The project owner shall submit the proposed protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 10 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.~~

~~**AQ-20**~~ ~~The project owner shall install and maintain a continuous emissions monitoring system (CEMS) to measure the following parameters:~~

~~CO concentration in ppmv~~

~~Concentrations shall be corrected to 15 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine, in accordance with approved SCAQMD Rule 218 CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.~~

~~The CEMS shall be installed and operated to measure the CO concentration over a 15 minute averaging time period.~~

~~The CEMS shall convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below and record the hourly emission rates on a continuous basis.~~

~~CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9%-%O_2 d)][(Qg*HHV)/10E6], where~~

~~K = 7.267*10^{-8} (lbs/scf)/ppm~~

~~Cco = Average of 4 consecutive 15 min. average CO concentrations, ppm~~

~~Fd = 8710 dscf/MMBTU natural gas~~

~~%O_2, d= Hourly average % by volume O_2 dry, corresponding to Cco~~

~~Qg = Fuel gas usage during the hour, scf/hr~~

~~HHV = Gross high heating value of the fuel gas, BTU/scf~~

~~[Rule 1303 – BACT, Rule 1703-PSD]~~

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

~~**AQ-21** The project owner shall install and maintain a CEMS to measure the following parameters:~~

~~NOx concentration in ppmv~~

~~Concentrations shall be corrected to 15 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine, in accordance with approved SCAQMD Regulation XX CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.~~

~~Rule 2012 provisional relative accuracy test audit (RATA) testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start up and the provisional certification date of the CEMS, the project owner shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).~~

~~[Rule 1703 – PSD, Rule 2005, Rule 2012]~~

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

~~**AQ-22** The project owner shall install this equipment according to the following requirements:~~

~~Construction shall commence within 12 months of the date of the permit to construct unless the permit is extended, but in no case should the start of construction exceed 18 months from the date of the permit to construct. Construction shall not be discontinued for a period of 18 months or more.~~

~~[Rule 205, 40 CFR Part 52]~~

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

~~**AQ-23** The project owner shall upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02 project.~~

~~[CEQA]~~

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

~~**AQ-24** The project owner shall install this equipment according to the following requirements:~~

~~Total commissioning hours shall not exceed 491 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 47 hours of operation for each turbine. Only one turbine shall undergo steam blows at any one time and at a load of no more than 50%. During steam blows, the other two turbines in the block shall not be fired. During all other commissioning activities outside of steam blows, a maximum of 2 turbines may be operated at any one time.~~

~~The project owner shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning.~~

~~The project owner shall provide SCAQMD with written notification of the initial startup date. Written records of commissioning start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.~~

~~[Rule 1303 – BACT, Rule 1303 – Offsets, Rule 1703 – PSD, Rule 2005]~~

~~**Verification:** The project owner shall submit CEMS records to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-25** The project owner shall, upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~The project owner shall record the total net power generated in a calendar month in megawatt-hours.~~

~~The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:~~

~~GHG = 60.08 * FF~~

~~Where, GHG is the greenhouse gas emissions in tons of CO2 and FF is the monthly fuel usage in millions standard cubic feet.~~

~~The project owner shall calculate and record the GHG emissions in pounds per net megawatt-hour on a 12-month rolling average. The GHG emissions from this equipment shall not exceed 652,827 tons per year on a 12-month rolling average basis. The calendar annual average GHG emissions shall not exceed 1,053.7 lbs per net megawatt-hour (1,138.0 lbs per net megawatt hour inclusive of equipment degradation).~~

~~The project owner shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.~~

~~[Rule 1714]~~

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

~~**AQ-26** The project owner shall, upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~The project owner shall record the total gross power generated in a calendar month in megawatt-hours.~~

~~The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:~~

~~GHG = 60.08 * FF~~

~~Where, GHG is the greenhouse gas emissions in tons of CO2 and FF is the monthly fuel usage in millions standard cubic feet.~~

~~The project owner shall calculate and record the GHG emissions in pounds per gross megawatt-hours on a 12-month rolling average. The calendar annual average GHG emissions shall not exceed 1,000 lbs per gross megawatt-hour, or the applicable limit which is published in the final EPA rule.~~

~~The project owner shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.~~

~~[40 CFR60 Subpart KKKK]~~

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

~~**AQ-27**~~ ~~This equipment shall not be operated unless the facility holds 39,854 pounds of NOx RECLAIM Trading Credits (RTCs) in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 62,507 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.~~

~~[Rule 2005]~~

~~**Verification:**~~ ~~The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-28**~~ ~~This equipment shall not be operated unless the facility holds 2,694 pounds of SOx RECLAIM Trading Credits (RTCs) in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 3,798 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective~~

~~expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.~~

~~[Rule 2005]~~

~~**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-29** The project owner shall provide to the District a source test report in accordance with the following specifications:~~

- ~~Source test results shall be submitted to the District no later than 60 days after the source tests required under conditions **AQ-17**, **AQ-18**, and **AQ-19** are conducted.~~
- ~~Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid particulate matter (PM) emissions, if required to be tested, shall also be reported in terms of grains/dry standard cubic feet.~~
- ~~All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.~~

~~Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (cubic feet per hour), the flue gas temperature, and the generator power output (MW) under which the test was conducted.~~

~~[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]~~

~~**Verification:** The project owner shall submit the proposed protocol for the initial source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test date and time.~~

~~**AQ-30** The project owner shall keep records in a manner approved by the District, for the following parameter(s) or item(s):~~

~~Commissioning hours and type of control and fuel use~~

~~Date, time, and duration of each start-up and shutdown, and the type of startup (cold, warm, or hot).~~

~~In addition to the requirements of a certified continuous emissions monitoring system (CEMS), natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification~~

~~Minute by minute data (NO_2 and O_2 concentration and fuel flow rate at a minimum) for each turbine start up~~

~~Monthly number of hours each turbine is operated with duct firing~~

~~Total annual power output in MWh~~

~~[Rule 1303(b)(2) - Offsets]~~

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

~~**DUCT BURNER**~~

~~**AQ-31** This equipment shall not be operated unless the facility holds 13,488 pounds of NOx RECLAIM Trading Credits (RTCs) in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 21,155 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.~~

~~[Rule 2005]~~

~~**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-32** This equipment shall not be operated unless the facility holds 912 pounds of SOx RECLAIM Trading Credits (RTCs) in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 1,286 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.~~

~~[Rule 2005]~~

~~**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~SCR~~

~~AQ-33~~ ~~The 5 ppmv NH_3 emission limit is averaged over 60 minutes at 15% O_2, dry basis. The project owner shall calculate and continuously record the NH_3 slip concentration using the following:~~

~~NH_3 (ppmv) = [a–b*(c*1.2)/1E+06]*1E+06/b where,~~

~~a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)~~

~~b = dry exhaust gas flow rate (standard cubic feet (scf)/hr)/385.3 scf/lb-mol)~~

~~c = change in measured NOx across the SCR (ppmvd at 15% O_2)~~

~~The project owner shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months. The NOx analyzer shall be installed and operated within 90 days of initial start-up.~~

~~The project owner shall use the above described method or another alternative method approved by the Executive Officer.~~

~~The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.~~

~~[Rule 1303(a)(1) – BACT]~~

~~Verification:~~ ~~The project owner shall include exceedances of the hourly ammonia slip limit as part of the Quarterly Operation Reports (**AQ-SC8**). Exceedances of the ammonia limit shall be reported as prescribed herein. Chronic exceedances of the ammonia slip limit shall be identified by the project owner and confirmed by the CPM within 60 days of the fourth quarter Quarterly Operation Report (**AQ-SC8**) being submitted to the CPM. If a chronic exceedance is identified and confirmed, the project owner shall work in conjunction with the CPM to develop a reasonable compliance plan to investigate and redress the chronic exceedance of the ammonia slip limit within 60 days of the above confirmation. The project owner shall include all calibration results performed as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~AQ-34~~ ~~The project owner shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.~~

~~The project owner shall also install and maintain a device to continuously record the parameter being measured.~~

~~The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.~~

~~The injected ammonia rate shall be maintained within 11.8 gal/min and 33 gal/min except during start ups and shutdowns~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-35** The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.~~

~~The project owner shall also install and maintain a device to continuously record the parameter being measured.~~

~~The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.~~

~~The exhaust temperature at the inlet of the selective catalytic reduction shall be maintained between 400-700 deg F except during start up and shutdowns~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-36** The project owner shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the selective catalytic reduction catalyst bed in inches of water column.~~

~~The project owner shall also install and maintain a device to continuously record the parameter being measured.~~

~~The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.~~

~~The differential pressure shall be maintained between 1.5 " WC and 3.5 " WC.~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-37** For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.~~

~~Condition Number **AQ-34**~~

~~Condition Number **AQ-35**~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-38** For the purpose of the following condition numbers, continuous monitoring shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.~~

~~Condition Number: **AQ-36**~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-39** The project owner shall upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-2 project.~~

~~[CEQA]~~

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

~~**CO CATALYST**~~

~~**AQ-40** The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the CO Catalyst.~~

~~The project owner shall also install and maintain a device to continuously record the parameter being measured.~~

~~The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AMMONIA STORAGE TANK**~~

~~**AQ-41** The project owner shall vent this equipment, during filling, only to the vessel from which it is being filled.~~

~~[Rule 1303(a)(1)-BACT]~~

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

~~AQ-42~~ ~~The project owner shall install and maintain a pressure relief valve set at 50 pounds per square inch gage (psig).~~

~~[Rule 1303(a)(1)-BACT]~~

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

~~AQ-43~~ ~~The project owner shall upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-2 project.~~

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

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ACRONYMS

AAQS	Ambient Air Quality Standard
AERMOD	AMS/EPA Regulatory Model
AFC	Application for Certification
APCO	Air Pollution Control Officer
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMD	Air Quality Management District
AQMP	Air Quality Management Plan
ARB	California Air Resources Board
BACT	Best Available Control Technology
Btu	British Thermal Unit
CAAQS	California Ambient Air Quality Standards
CCR	California Code of Regulations
CEC	California Energy Commission (or Energy Commission)
CEMS	Continuous Emission Monitoring System
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPM	(CEC) Compliance Project Manager
Degrees F	Degrees Fahrenheit
DSCFM	Dry Standard Cubic Feet per Minute
ERC	Emission Reduction Credit
FDOC	Final Determination of Compliance
FSA	Final Staff Assessment
GHG	Greenhouse Gas
gr/scf	Grains per Standard Cubic Foot (7,000 grains = 1 pound)
H_2S	Hydrogen Sulfide
HSC	Health and Safety Code
lb/mmscf	Pounds per Million Standard Cubic Feet
lbs	Pounds
LLC	Limited Liability Company
LORS	Laws, Ordinances, Regulations and Standards
MCR	Monthly Compliance Report
$\mu g/m^3$	microgram per cubic meter

mg/m^3	milligrams per cubic meter
MMBtu/hr	Million British Thermal Units per Hour
MW	Megawatts (1,000,000 Watts)
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen or Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
PDOC	Preliminary Determination of Compliance
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSA	Preliminary Staff Assessment
PSD	Prevention of Significant Deterioration
PTA	Petition to Amend
PTC	Permit to Construct
PTE	Potential to Emit
PTO	Permit to Operate
PVMRM	Plume Volume Molar Ratio Method
RECLAIM	Regional Clean Air Incentives Market
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
scf	standard cubic feet
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_4	Sulfate
SOx	Oxides of Sulfur
SCAB	South Coast Air Basin
SWPPP	Storm Water Pollution Prevention Plan
tpy	tons per year

U.S. EPA	United States Environmental Protection Agency
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compounds

AIR QUALITY APPENDIX AIR-1
GREENHOUSE GAS EMISSIONS

Wenjun Qian, Ph.D., P.E and David Vidaver

SUMMARY

The Amended Huntington Beach Energy Project (Amended HBEP) project is a proposed addition to the state's electricity system. It would be an efficient, new, dispatchable natural gas-fired combined-cycle and simple-cycle power plant that would provide fast start capabilities but would produce greenhouse gas (GHG) emissions while generating electricity for California consumers. 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 Amended HBEP would contribute to a reduction of the California GHG emissions and GHG emission rate average. The relative efficiency of the Amended HBEP 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 inter-connected system of generation sources. Operation of one power plant, like the Amended HBEP, affects all other power plants in the interconnected system. While the Amended HBEP burns natural gas for fuel and thus produces GHG emissions that contribute cumulatively to climate change, it would have a beneficial impact on system operation and facilitate a reduction in GHG emissions in several ways:

- When dispatched,[6] the Amended HBEP 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 power plants that the project would displace, the addition of the Amended HBEP would contribute to a reduction of California and overall Western Electricity Coordinating Council system GHG[7] emissions and GHG emission rate average.
- The Amended HBEP would provide fast start and dispatch flexibility capabilities necessary to integrate expected and desired additional amounts of variable renewable generation (also known as "variable" or "intermittent" energy resources) to meet the state's renewable portfolio standard (RPS) and GHG emission reduction targets.

[6] 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.

[7] 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 fuel combustion dominate greenhouse gas (GHG) emissions from power plants, the terms CO_2 and GHG are used interchangeably in this section.

- The Amended HBEP would replace capacity and generation mostly provided by aging, high GHG emitting power plants, some of which that are likely to retire in order to comply with the State Water Resource Control Board's (SWRCB) policy on the use of once through cooling (OTC).
- The Amended HBEP would replace less efficient generation in the South Coast local reliability area required to meet local reliability needs, reducing the GHG emissions associated with providing local reliability services and facilitating the retirement of aging, high GHG-emitting resources in the area.
- The combined-cycle portion of the Amended HBEP would have a higher thermal efficiency than the approved combined-cycle turbines of the licensed HBEP. The simple-cycle turbines proposed for the Amended HBEP would be less efficient than the approved combined-cycle turbines, but they can provide additional flexibility to support the intermittent/variable renewable generation[8].

CONCLUSIONS

The Amended HBEP would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California. Thus, staff believes that the Amended HBEP 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. In addition, it would provide flexible, dispatchable and fast ramping power in relatively small increments of capacity, which should improve the electric system reliability in a high-renewables, low-GHG system.

Staff notes that mandatory reporting of GHG emissions per federal government and Air Resources Board greenhouse gas regulations would occur, and these reports would enable these agencies to gather the information needed to regulate the Amended HBEP in trading markets, such as those that are expected to be required by regulations implementing the California Global Warming Solutions Act of 2006 (AB 32). The Amended HBEP may be subject to additional reporting requirements and GHG reduction and trading requirements as these regulations are more fully developed and implemented.

[8] Variable and intermittent are often used interchangeably, but variable more accurately reflects the integration issues of renewables into the California grid. Winds can slow across a wind farm or cloud cover can shade portions of a solar field, temporarily reducing unit or facility output, but not shut down the unit or facility.

Staff does not believe that the GHG emission increases from construction activities would be significant for several reasons. First, construction emissions would be temporary and 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 meet 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 would likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. For all these reasons, staff concludes that the emission of greenhouse gases during construction would be sufficiently reduced and would, therefore, not be significant.

The Amended HBEP is subject to the Greenhouse Gases Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.). The Amended HBEP would meet the standard of 0.5 metric tonnes CO_2 per megawatt-hour ($MTCO_2$/MWh) with a rating of 0.381 $MTCO_2$/MWh, which would be less than the rating of 0.479 $MTCO_2$/MWh for the licensed HBEP (CEC 2014bb).

The GE 7FA.05 combined-cycle turbines are 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 CO_2/MWh, gross) or (1,030 lb CO_2/ MWh, net) for base load natural gas fueled turbines. The GE LMS-100PB simple-cycle turbines are expected to comply with the limit of 120 lb CO_2 per million Btus (MMBtu) of natural gas heat input for non-base load natural gas fueled turbines. Should the combined-cycle turbines operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. conditions of certification **AQ-14** and **AQ-58** would ensure compliance with the new standards.

Staff has reached the following conclusions about the Amended HBEP based on CEQA guidelines:

- The Amended HBEP would have less than significant GHG emissions impacts because:
  - o The combined cycle portion of the Amended HBEP would have lower heat rate and lower GHG emissions than the units utilizing OTC that currently provide a share of the local reliability needs for the local capacity area (LCA). It would also be dispatched in lieu of less efficient, higher-emitting combined cycles when providing local reliability services.
  - o The proposed simple cycle turbines of the Amended HBEP would have lower heat rates and lower GHG emissions than those of the existing peaking facilities in the LCA.
  - o The Amended HBEP would facilitate the integration of renewable energy resources that would lower the state-wide GHG emissions from the electricity sector.

- The Amended HBEP would have less than significant impacts by complying with applicable regulations and plans related to the reduction of GHG emissions as follows:
  - The Amended HBEP would be subject to compliance with the AB 32 Cap and Trade regulation that implements the state's regulatory plan for reducing GHG emissions from the electricity sector;
  - The construction emissions mitigation measures that staff recommends to address criteria pollutant emissions would further minimize GHG emissions. The use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of future ARB regulations to reduce GHG from construction vehicles and equipment; and

The Amended HBEP would be consistent with all three main conditions in the Energy Commission's 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

Wenjun Qian, Ph.D., P.E.

INTRODUCTION

GHG emissions are not criteria pollutants with direct impacts; 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,[9] 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 (CAA). For fossil fuel-fired power plants, the GHG emissions include primarily CO_2, 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[10].

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

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.

[9] 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).

[10] 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) for ease of comparison.

After the approval of the HBEP, U.S. EPA published new source performance standards (NSPS) for greenhouse gas emissions for new, modified, and reconstructed fossil fuel-fired electric utility generating units on October 23, 2015. The Amended HBEP turbines would be subject to these new requirements.

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

Applicable LORS	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. However, see discussions below.
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 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 CO_2E. The Amended HBEP is subject to the GHG PSD analysis.
40 Code of Federal Regulations (CFR) Parts 60, 70, 71 and 98	On October 23, 2015, U.S. EPA published new source performance standards (NSPS) for greenhouse gas emissions for new, modified, and reconstructed fossil fuel-fired electric utility generating units. The Amended HBEP turbines would be subject to these requirements.
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year. This requirement is triggered by this facility.
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).
Local	
Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases, Gas Turbines	This rule establishes preconstruction review requirements for greenhouse gases (GHG). This rule is consistent with federal PSD rule as defined in 40 CFR Part 52.21. This rule requires the owner or operator of a new major source or a major modification to obtain a PSD permit prior to commencing construction.

COMPLIANCE WITH GHG LORS

The Amended HBEP 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 the Amended HBEP 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. The Amended HBEP, 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 Western Climate Initiative (WCI), Inc. 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. Similarly, the Amended HBEP would be subject to federal mandatory reporting of GHG emissions.

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 Amended HBEP would emit at 0.381 $MTCO_2$/MWh, which complies with California's SB1368 Emissions Performance Standard (EPS) limit of 1,100 lb CO_2/MWh (0.5 MT/MWh).

The PDOC shows that the proposed combined-cycle turbines and simple-cycle turbines would comply with the new NSPS for greenhouse gas emissions for new fossil fuel-fired electric utility generating units. See more details in the section below.

SCAQMD Rule 1714 establishes preconstruction review requirements for GHGs and the Amended HBEP is evaluated for these requirements in the PDOC. The Amended HBEP would be a major PSD source. The SCAQMD performed a PSD BACT analysis for GHGs and concluded thermal efficiency is the only technically and economically feasible alternative for CO_2/GHG emissions control for the Amended HBEP. The current design proposed for the Amended HBEP meets the BACT requirement for GHG emission reductions. 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.

GHG ANALYSIS

California is actively pursuing policies to reduce GHG emissions that include adding low-GHG emitting renewable electricity generation resources to the system. 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 2014). 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 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).

Recent data collected at Mauna Loa, Hawaii indicate that atmospheric CO_2 concentration now exceed 400 ppm all year, and new research suggests that values will remain above this level (Betts et al 2016).

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.

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 the section **The Impact of the Amended HBEP on GHG Emissions from the State's Electricity Sector** 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.

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[11] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the ARB to adopt standards that will reduce 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 will 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 will 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 ($MMTCO_2E$) of greenhouse gases. In 2013, ARB used EPA's updated information to re-calculate that level to 431 million metric tons.

[11] 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 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 .

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 will decline over time. The state will distribute allowances, which are tradable permits, equal to the emissions allowed under the cap. Sources under the cap will 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[12] 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 will continue in 2014 to provide advice to the ARB.

[12] 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)

It is likely that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will 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.

SB 1368,[13] 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[14] (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.[15] If a project, in state or out of state, plans to sell electricity or capacity to California utilities, those utilities will 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)].

The Amended HBEP 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 the Amended HBEP 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 will increase encouraging innovation by market participants to reduce their GHG emissions. Thus, the Amended HBEP, as a GHG cap-and-trade participant, would be consistent with California's AB 32 Program.

On October 23, 2015, the U.S. EPA published 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.

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[13] Public Utilities Code § 8340 et seq.

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

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

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 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 PDOC shows that the emission rate of the proposed combined-cycle unit would be 967.6 lbs CO_2 per MWh (net), assuming 8 percent performance degradation (SCAQMD 2016b), which is less than the allowable 1,030 lbs CO_2/MWh (net). The GE LMS-100PB simple cycle turbines are expected to have capacity factors less than their lower heating value efficiency and thus would be required to emit no more than 120 lb CO_2 per million Btus of heat input. Each GE LMS-100PB turbine is estimated to emit 117 lb CO_2 per MMBtu, which rounds to 120 lb CO_2 per MMBtu at two digits of precision. Should the combined cycle operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. Conditions of certification **AQ-14** and **AQ-58** would ensure compliance with the new standards.

Also on October 23, 2015, the U.S. EPA published 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 the Amended HBEP at this time. However, the Amended HBEP 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. On February 9, 2016, the Supreme Court stayed implementation of the so-called "Clean Power Plan" pending judicial review.

ELECTRICITY AND 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[16] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability.

[16] See CEC 2009b, page 95.

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.

GHG EMISSIONS FROM AMENDED HBEP

Construction of the Amended HBEP

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in temporary, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. Construction of the Amended HBEP project would involve 120 months of activity. The project owner provided annual GHG emission estimate for the construction phase. The GHG emissions estimate is presented below in **Greenhouse Gas Table 2**. The term CO_2E represents the total GHG emissions after weighting by the appropriate global warming potential.

Greenhouse Gas Table 2 also shows the maximum annual construction GHG emissions approved for the licensed HBEP. Except for the CH_4 emissions, the maximum annual construction GHG emissions estimated for the Amended HBEP would be higher than those approved for the licensed HBEP because of higher offsite emissions estimated from offsite delivery and material hauling trucks.

Greenhouse Gas Table 2
Estimated Maximum Annual Construction Greenhouse Gas Emissions

Source	CO_2	CH_4	N_2O	CO_2E
Amended HBEP				
Construction Total (Metric Tons/year)	8,289	0.13	0.063	8,311
Licensed HBEP				
Construction Total (Metric Tons/year)	2,938	0.14	0.06	2,960

Source: HBEP 2015a, CEC 2014bb

Operations of the Amended HBEP

The primary sources of GHG during operation of the Amended HBEP 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 estimated GHG emissions for the Amended HBEP on an annual basis assuming the facility would operate at maximum permitted emissions levels. 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.

Greenhouse Gas Table 3
Amended HBEP, Estimated Potential Greenhouse Gas (GHG) Emissions

Emissions Source	Operational GHG Emissions ($MTCO_2E/yr$)[a]
Amended HBEP	
Carbon Dioxide (CO_2)	1,782,131
Methane (CH_4)	840
Nitrous Oxide (N_2O)	1,001
Sulfur Hexafluoride (SF_6) Leakage	65.2
Total Project GHG Emissions ($MTCO_2E/yr$)	**1,784,036**
Estimated Annual Energy Output (MWh/yr)[b]	4,676,327
Estimated Annualized GHG Performance ($MTCO_2/MWh$)	**0.381**
Licensed HBEP	
Total Project GHG Emissions ($MTCO_2/yr$)	1,997,634
Estimated Annual Energy Output (MWh/yr)	4,170,821
Estimated Annualized GHG Performance ($MTCO_2/MWh$)	0.479

Source: CEC 2014bb, HBEP 2016n, SCAQMD 2016b, and independent staff analysis
Notes: [a.] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b.] Annualized basis uses the project owner's assumed maximum permitted operating basis.

The project owner expects the gross plant capacity factor of the Amended HBEP (including the combined-cycle and simple-cycle turbines) to be above 60 percent (HBEP 2015a). Therefore, the Amended HBEP would be subject to SB 1368 Greenhouse Gas Emission Performance Standard of 0.500 $MTCO_2$/MWh. The estimated annual GHG performance would be approximately 0.381 $MTCO_2$/MWh, which would meet the Emission Performance Standard of 0.500 $MTCO_2$/MWh, averaged over all the turbines.

Greenhouse Gas Table 3 also shows the approved GHG emissions for the licensed HBEP for comparison purposes. The Amended HBEP would produce more energy with less GHG emissions compared to the licensed HBEP. The estimated annual GHG performance (0.381 $MTCO_2$/MWh) of the Amended HBEP would be better (lower $MTCO_2$/MWh) than that estimated for the licensed HBEP (0.479 $MTCO_2$/MWh).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

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

METHOD AND THRESHOLDS FOR DETERMINING SIGNIFICANCE

The CEQA guidelines provide three factors for lead agencies to consider when assessing the significance of impacts for the analysis of GHG emissions impacts (CEQA Guidelines, tit. 14, §15064.4).

- *The extent to which the project may increase or reduce greenhouse gas emissions as compared to the existing environmental setting;*
- *Whether the project emissions exceed a threshold of significance that the lead agency determines applies to the project; and*
- *The extent to which the project complies with regulations or requirements adopted to implement a statewide, regional, or local plan for the reduction or mitigation of greenhouse gas emissions. Such requirements must be adopted by the relevant public agency through a public review process and must reduce or mitigate the project's incremental contribution of greenhouse gas emissions. If there is substantial evidence that the possible effects of a particular project are still cumulatively considerable notwithstanding compliance with the adopted regulations or requirements, an EIR must be prepared for the project.*

Staff evaluates the emissions of the project in the context of the electricity sector as a whole and the AB 32 Scoping Plan implementation efforts for the sector, including the cap and trade regulation that constitutes the state's primary mechanism for reducing GHG emissions from the electricity sector. The Energy Commission's assessment approach does not include a specific numeric threshold of significance for GHG emissions; rather the assessment is completed in the context of how the project will affect the electricity sector's emissions based on its proposed role and its compliance with applicable regulations and policies.

Included in this sector-wide GHG emission analysis method is the determination of whether a project is consistent with the Avenal precedent decision, which requires a finding as a conclusion of law that any new natural gas-fired power plant certified by the Energy Commission "must:

- not increase the overall system heat rate for natural gas plants;
- not interfere with generation from existing renewables or with the integration of new renewable generation; and
- taking into account the two preceding factors, reduce system-wide GHG emissions."[17]

CONSTRUCTION IMPACTS

Staff believes that the small GHG emission increases from construction activities would not be significant for several reasons. First, the intermittent emissions during the construction phase are 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 will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of future ARB regulations to reduce GHG from construction vehicles and equipment.

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[17] Final Commission Decision, Avenal Energy Application for Certification (08-AFC-1) December 2009, p. 114.

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 Amended HBEP 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 operation and greenhouse gas emissions from the older, existing power plants; potentially displacing local electricity generation; the penetration of renewable resources; and accelerating generation retirements and replacements, including facilities 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 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.

PROPOSED CONDITIONS OF CERTIFICATION

Conditions of certification **AQ-3**, **AQ-14**, **AQ-53**, **AQ-55**, and **AQ-58** in the Air Quality section relate to the greenhouse gas emissions from project operation are proposed. The facility owner would 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. Similarly, the Amended HBEP would be subject to federal mandatory reporting of GHG emissions. The facility owner may have to provide additional reports and GHG reductions, depending on the future regulations formulated by the U.S. EPA or the ARB.

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

David Vidaver

SUMMARY

Both the development of the HBEP as approved and 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, amended project 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 THE HBEP ON GHG EMISSIONS

The Energy Commission previously found that the HBEP would unambiguously reduce GHG emissions from the state's electricity sector (CEC 2014bb). 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 will be that from coal-fired generators, whose GHG emissions are even higher per MWh than those from natural gas-fired generators, as they are less thermally efficient and use a fuel with a higher carbon content per Btu.

IMPACT OF THE PROPOSED AMENDMENT TO THE HBEP ON GHG EMISSIONS

It follows from the previous section that development of the Amended HBEP would reduce GHG emissions from the electricity sector compared to the alternative of developing neither the project as previously approved or as now proposed.

It is not possible to determine – with any accuracy – the GHG emissions that would be expected from an electricity system that includes the licensed HBEP with one that includes the Amended HBEP. 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.[18] More importantly, the ceiling is for GHG emissions *from the plant itself*; its consideration ignores the quantity of GHG emissions from the generators that are displaced.

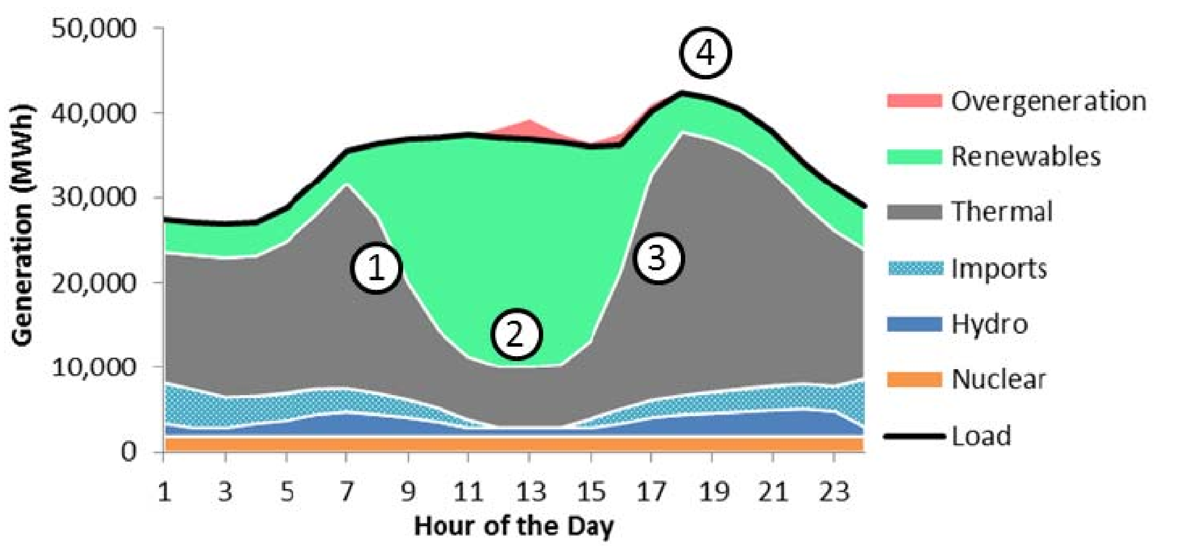
Similarly, a comparison of the thermal efficiencies of the two projects (e.g., at full load) does not provide any information regarding their expected GHG emissions or the system-wide emissions that would result from their development. While the combined cycle portion of the proposed project has a higher thermal efficiency than the approved 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. Similarly, while the LMS 100s now proposed are less efficient than the approved combined cycles, they are also more flexible, able to start up faster, cycle on and off multiple times per day, turn down to lower levels of output, etc. Again, they would be dispatched differently than a combined cycle, and thus displace different existing gas-fired resources.

It is very likely, however, that the Amended HBEP would lead to greater reductions in GHG emissions than the licensed HBEP, as its increased flexibility 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 will develop over the next 15 years as the RPS increases to 50 percent in 2030. Much of the additional renewable energy will 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).

[18] 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.

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 will 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
California Generation Typical for a Non-Summer Day ("Duck" Chart)



Source: CA ISO 2014

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 will 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.[19]

[19] 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.

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ACRONYMS

AB	Assembly Bill
ARB	California Air Resources Board
CAA	Clean Air Act
CalEPA	California Environmental Protection Agency
CA ISO	California Independent System Operator
CCCC	California Climate Change Center
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2E	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
EIR	Environmental Impact Report
EPS	Emission Performance Standard
GCC	Global Climate Change
GHG	Greenhouse Gas
GWh	Gigawatt-hour
GWP	Global Warming Potential
HBEP	Huntington Beach Energy Project
HFC	Hydrofluorocarbons
HSC	Health and Safety Code
IEPR	Integrated Energy Policy Report
IPCC	Intergovernmental Panel on Climate Change
LCA	Local Capacity Area
LTPP	Long-term Procurement Planning
MT	Metric tones
$MTCO_2E$	Metric Tons of CO_2-Equivalent
MW	Megawatts
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen or Nitrogen Oxides
NSPS	New Source Performance Standard

OTC	Once-Through Cooling
PFC	Perfluorocarbons
PSA	Preliminary Staff Assessment
PSD	Prevention of Significant Deterioration
RPS	Renewables Portfolio Standard
SB	Senate Bill
SF_6	Sulfur hexafluoride
SWRCB	State Water Resource Control Board
U.S. EPA	United States Environmental Protection Agency
WCI	Western Climate Initiative

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision

BIOLOGICAL RESOURCES

Tim Singer and Heather Blair

SUMMARY OF CONCLUSIONS

The proposed modifications in the Petition to Amend (PTA) for the Huntington Beach Energy Project (HBEP) would not result in new significant impacts on biological resources, substantial increases in the severity of previously identified significant impacts, or necessitate any material changes to the biological resource conditions of certification identified in the California Energy Commission Final Decision (Decision) for the approved HBEP (CEC 2014bb) to mitigate impacts or maintain compliance with applicable laws, ordinances, regulations, and standards (LORS) related to biological resources. Therefore, in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162, staff concludes that no supplementation to the Decision is necessary for biological resources.

Consistent with the Decision for the approved HBEP, with implementation of the previously approved conditions of certification (with minor, immaterial changes), the amended HBEP would not result in significant direct, indirect, or cumulative impacts to biological resources and would conform to all applicable LORS related to biological resources.

INTRODUCTION

This section provides the Energy Commission staff's analysis of potential impacts to biological resources from proposed changes to the approved HBEP. It updates any pertinent setting information and focuses on the potential for new impacts or increases in the severity of previously identified impacts and the need for new or revised conditions of certification.

SUMMARY OF THE COMMISSION DECISION

The Energy Commission considered the potential for the HBEP to impact state and federally-listed species, species of special concern, and other resources of critical biological interest, such as wetlands and unique habitats. The Decision addressed the potential for project-related noise and lighting to affect special-status bird species in the adjacent Magnolia Marsh, the potential for birds to collide with project structures, and the potential for the project's nitrogen emissions to impact sensitive species and their habitats. The Commission found that, with implementation of conditions of certification **BIO-1** through **BIO-8**, the HBEP will not result in significant direct, indirect, or cumulative impacts to biological resources and will conform to all applicable LORS related to biological resources (CEC 2014bb).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS COMPLIANCE

There have not been any changes to applicable LORS since the approval of the original HBEP in November 2014. Additionally, the proposed amendment would not trigger the consideration of any new LORS that were not applicable to the approved HBEP.

ENVIRONMENTAL IMPACT ANALYSIS

Staff reviewed the PTA for potential environmental effects. Based on this review, staff determined there are no new or increased significant impacts to biological resources.

However, minor updates to the affected environment as described for the approved HBEP are presented below to reflect recent changes to the nomenclature and status of some special-status species, as well as the use of the adjacent Plains All American Tank Farm for construction worker parking and construction laydown. None of these changes would merit revisions to the conditions of certification or any additional mitigation. Additionally, proposed changes to the HBEP would result in minor changes to some construction and operation impacts, as identified below.

SPECIAL-STATUS SPECIES

Special-status Plants

Four special-status plant species were identified in an updated search of the California Natural Diversity Database (CNDDB) within a 10-mile radius of the amended HBEP that were not considered in the original HBEP proceeding. These species are: Brand's star phacelia (*Phacelia stellaris*; California Rare Plant Rank [CRPR] 1B.1), decumbent goldenbush (*Isocoma menziesii var. decumbens*; CRPR 1B.2), Robinson's pepper-grass (*Lepidium virginicum var. robinsonii;* CRPR 4.3), and San Diego button-celery (*Eryngium aristulatum var. parishii*; federally endangered, state endangered, CRPR 1B.1). Due to a lack of suitable habitat, none of these species are expected to occur within the amended project area. No impacts would occur.

Light-footed Ridgway's (Clapper) Rail

The federally and state-endangered light-footed clapper rail (*Rallus longirostris levipes*), as it was referred to in the original HBEP proceeding, was one of the special-status species considered by staff in its original analysis. It has been reclassified taxonomically and renamed by the American Ornithologist Union and ascribed to the Ridgway's rail, *Rallus obsoletus* (Chesser et al. 2014). The common name for the southern California subspecies soon should be legally adopted by the wildlife agencies in recognition of this nomenclatural change. The light-footed clapper rail will then be called the light-footed Ridgway's rail (*R. obsoletus levipes*)(Zembal et al. 2015).

Based on the 2015 report on the status and distribution of light-footed Ridgway's rail in the Huntington Beach Wetlands Complex (Zembal et al. 2015), a pair was observed in the Brookhurst Marsh in 2012 through 2015. According to Dr. Gordon Smith of the Huntington Beach Wetlands Conservancy (Pers. Comm., Smith 2016), an individual light-footed Ridgway's rail was observed by California Department of Fish and Wildlife staff in Magnolia Marsh in 2015. This species has not been documented breeding in Magnolia Marsh, consistent with the information presented in the Decision for the approved HBEP, although habitat conditions for light-footed Ridgway's rail in the marsh continue to improve. Condition of certification **BIO-8** continues to apply, which requires an assessment of habitat and potentially focused surveys for light-footed Ridgway's rail in advance of construction. With implementation of this condition of certification, impacts to light-footed Ridgway's rail remain less than significant, as stated in the Decision for the approved HBEP.

Nesting Birds

The amended HBEP would improve access to the proposed construction laydown and parking area at the Plains All American Tank Farm. This improved access would require the removal of several trees west of the intersection of Magnolia Street and Banning Avenue. Potential impacts to nesting birds would be avoided and minimized through implementation of condition of certification **BIO-8**, which requires a survey for nesting birds in advance of construction and establishment of no-disturbance buffers around active nests. With implementation of this condition of certification, impacts to nesting birds remain less than significant, as stated in the Decision for the approved HBEP.

AVIAN COLLISION

The height of the approved HBEP's exhaust stacks was 120 feet. The amended HBEP includes 150-foot-tall exhaust stacks. Typically, structures shorter than 350 feet are not considered a substantial collision threat to migrating birds. The proposed 30-foot increase in stack height would not increase the risk of avian collisions; impacts would remain less than significant as stated in the Decision for the approved HBEP.

AIR EMISSIONS – NITROGEN DEPOSITION

Staff determined that nitrogen emissions from the amended HBEP would be approximately 42 percent less than those of the approved HBEP. Although the exhaust stack dimensions of the amended HBEP would be different than those approved, the formation of depositional nitrogen from gaseous nitrogen compounds requires time and sunlight, which are independent of exhaust stack parameters. The reduction in nitrogen emissions would lead to a reduction of nitrogen deposition. In addition, the amended HBEP would be required to purchase RECLAIM Trading Credits to offset the annual nitrogen emissions on a 1:1 offset ratio (see the **AIR QUALITY** section of this document). The amended HBEP would not result in a net increase in nitrogen emissions in the South Coast Air Basin coastal zone. Nitrogen deposition impacts on sensitive species and habitats would remain less than significant as identified in the Decision for the approved HBEP.

CHANGES TO THE AFFECTED ENVIRONMENT

The amended HBEP proposes to utilize an additional 20 acres at the former Plains All American Tank Farm site (Plains site) for construction worker parking and construction laydown. The Plains site, which consists mostly of pavement, gravel, and disturbed soil, currently includes three empty petroleum storage tanks, along with containment berms and associated infrastructure. The site was surveyed on September 2, 2015, and at that time, other than several mature trees on-site, no natural vegetation or habitat was present. However, due to the Plains site's proximity to Magnolia Marsh, as well as the fact that preparation of the site for use as a laydown area will require demolition and ground disturbance, it is worth noting that all of the conditions (**BIO-1** through **BIO-8**) that apply to the originally licensed HBEP site would also apply to the Plains site. Implementation of these conditions of certification will ensure that no significant effects to biological resources would occur as a result of the changes to the affected environment.

CUMULATIVE IMPACTS

Staff analyzed relevant projects for potential cumulative impacts to the biological resources near HBEP. Staff has concluded that the HBEP amendment would not result in new significant impacts to biological resources; therefore the finding in the Decision that the HBEP would not contribute considerably to cumulative effects to biological resources would remain valid.

CONCLUSIONS AND RECOMMENDATIONS

Since approval of the original HBEP, minor updates to the affected environment are warranted to reflect the name change of the light-footed clapper rail to the light-footed Ridgway's rail, the status change of some special-status species, and the consideration of four special-status plant species that were newly identified in an updated CNDDB search (none of which have suitable habitat in the amended project area). Additionally, the status and distribution of the light-footed Ridgway's rail in the Huntington Beach Wetlands Complex was updated with 2015 census data; restoration efforts continue in the Magnolia Marsh and documented species occurrences have increased throughout the Huntington Beach Wetlands Complex, but breeding light-footed Ridgway's rail have not been documented in Magnolia Marsh. None of these updates to the affected environment would merit revisions to the conditions of certification or any additional mitigation.

The amended HBEP includes several proposed modifications pertinent to the assessment of impacts on biological resources: taller exhaust stacks, reduced nitrogen emissions, removal of additional trees, and the use of the Plains All American Tank Farm. None of the proposed modifications would result in new significant impacts, substantially increase the severity of previously identified significant impacts, or necessitate any material changes to the biological resource conditions of certification identified in the Decision for the approved HBEP to mitigate impacts or maintain compliance with LORS. Consistent with the Decision for the approved HBEP, with implementation of the previously approved conditions of certification (with minor, immaterial changes), the amended HBEP would not result in significant direct, indirect, or cumulative impacts to biological resources and would conform to all applicable LORS related to biological resources.

CONDITIONS OF CERTIFICATION

The following conditions of certification are excerpted from the November 2011 Decision for the approved HBEP (CEC 2014bb). As discussed in the "Conclusions and Recommendations" subsection above, staff is not proposing any material changes to these conditions. Staff has proposed minor edits to reflect recent changes to the nomenclature of the light-footed clapper rail, to ensure clarity, and to correct typographical errors. Deleted text is in ~~strikethrough~~ and new text is **<u>bold and underlined</u>**.

APPOINTMENT AND QUALIFICATIONS OF DESIGNATED BIOLOGIST

BIO-1 The project owner shall assign at least one Designated Biologist to the project. The project owner shall submit the resume of the proposed Designated Biologist, with at least three references and contact information, to the Energy Commission Compliance Project Manager (CPM) for approval and to the United States Fish and Wildlife Service (USFWS) and the California Department of Fish and Wildlife (CDFW) for review and comment. 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.

Current or prior possession of USFWS 10(a)(1)(A) permit and/or CDFW scientific collecting permit is preferred, but not required.

In lieu of the above requirements, the resume shall demonstrate to the satisfaction of the CPM, in consultation with CDFW and USFWS, that the proposed Designated Biologist or alternate has the appropriate training and background to effectively implement the conditions of certification.

The designated biologist may be replaced by submitting the required resume, references and contact information to the CPM for review and approval and to CDFW and USFWS for review and comment.

<u>Verification:</u> The project owner shall submit the specified information at least 75 days prior to the start of site mobilization or construction-related ground disturbance activities. No pre-construction site mobilization or construction related activities shall commence until a Designated Biologist has been approved by the CPM.

The project owner may replace a Designated Biologist by submitting the required resume, references and contact information to the CPM for review and approval and to the CDFW and USFWS for review and comment, at least ten working days prior to the termination or release of the then-current Designated Biologist. In an emergency, the project owner shall immediately notify the CPM to discuss the qualifications and approval of a short-term replacement while a permanent Designated Biologist is proposed to the CPM for consideration.

The CPM may withhold approval of a Designated Biologist based upon proof that a proposed Designated Biologist has repeatedly failed to comply with the conditions of any Energy Commission license as they pertain to biological resources. The CPM shall meet and confer with the project owner regarding the need to replace a Designated Biologist. Removal may occur if the CPM can establish that the Designated Biologist has repeatedly failed to comply with the conditions of the HBEP license that pertain to biological resources.

In the absence of comments, the CPM shall deem the Designated Biologist acceptable to USFWS and/or CDFW.

DUTIES OF DESIGNATED BIOLOGIST AND BIOLOGICAL MONITOR(S)

BIO-2 The project owner shall ensure that the Designated Biologist performs the following during any site (or related facilities) mobilization, ground disturbance, grading, construction, operation, closure, and restoration activities. The Designated Biologist may be assisted by the approved Biological Monitor(s) but remains the contact for the project owner and CPM. The Designated Biologist Duties shall include the following:

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

2. Consult on the preparation of the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) to be submitted by the project owner;

3. Be available to supervise, conduct and coordinate mitigation, monitoring, and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources, such as special status species or their habitat;

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

5. Inspect or direct the site personnel how to inspect active construction areas where animals may have become trapped prior to construction commencing each day. Inspect or direct the site personnel how to inspect the installation of structures that prevent entrapment or allow escape during periods of construction inactivity. Periodically inspect areas with high vehicle activity (e.g., parking lots) for animals in harm's way. Inspect soil or spoil stockpiles and dust abatement watering for compliance with Condition of Certification BIO-7. Inspect erosion control materials (e.g., hay bales) to confirm weed-free certification. Inspect weed infestations and monitor eradication measures to determine success. Inspect trash receptacles, monitor site personnel compliance with trash handling, pet prohibitions, and all other **Worker Environmental Awareness Program (**WEAP**)** components (Condition of Certification BIO-5);

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

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

8. Maintain written records of the tasks specified above and those included in the BRMIMP;

9. Train the Biological Monitors as appropriate, and ensure their familiarity with the BRMIMP, ~~Worker Environmental Awareness Program (~~WEAP~~)~~ training, and all permits; and

10. Maintain the ability to be in regular, direct communication with representatives of CDFW, USFWS, and CPM, including notifying these agencies of dead or injured listed species and reporting special status species observations to the California Natural Diversity Database.

Verification: The Designated Biologist shall notify the CPM of any noncompliance or special-status species injury or mortality within one (1) working day of the incident. The Designated Biologist shall submit in the **Monthly Compliance Reports (**MCR**)** to the CPM copies of all written reports and summaries that document construction activities that have the potential to affect biological resources. The Designated Biologist's written records will be made available for the CPM's inspection on request at any time during normal business hours. During project operation, the Designated Biologist(s) shall submit record summaries in the annual compliance report unless their duties cease, as approved by the CPM.

APPOINTMENT AND QUALIFICATIONS OF BIOLOGICAL MONITOR

BIO-3 The project owner shall submit the resume, at least three references, and contact information of the proposed Biological Monitor(s) to the CPM for approval. The resume shall demonstrate, to the satisfaction of the CPM, the appropriate education and experience to accomplish the assigned biological resource tasks.

The project owner may replace a Biological Monitor by submitting the required resume, references and contact information to the CPM for review and approval and to CDFW and USFWS for review and comment, at least ten working days prior to the termination or release of the then current Biological Monitor. In an emergency, the project owner shall immediately notify the CPM to discuss the qualifications and approval of a short-term replacement while a permanent Biological Monitor is proposed to the CPM for consideration.

Verification: The project owner shall submit the specified information to the CPM for approval at least 30 days prior to the start of any project-related site disturbance activities. Within 10 days of completion of training, the Designated Biologist shall submit a written statement to CPM confirming that individual Biological Monitor(s) have been trained including the date when training was completed. If additional biological monitors are needed during construction, the specified information shall be submitted to the CPM for approval at least 10 days prior to their first day of monitoring activities.

POWERS OF DESIGNATED BIOLOGIST/BIOLOGICAL MONITOR(S)

BIO-4 The project owner's construction/operation manager shall act on the advice of the Designated Biologist and Biological Monitor(s) to ensure conformance with the biological resources conditions of certification.

If required by the Designated Biologist and 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. The Designated Biologist shall:

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

2. Inform the project owner and the construction/operation manager when to resume activities;

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 would be instituted as a result of the work stoppage; and

4. The CPM, in coordination with CDFW or USFWS as appropriate, will determine if corrective action has been effective and will direct the project owner to take further corrective action as needed.

If the Designated Biologist is unavailable for direct consultation, the Biological Monitor shall act on behalf of the Designated Biologist.

Verification: The project owner shall ensure that the Designated Biologist or Biological Monitor notifies the CPM immediately (and no later than the morning following the incident, or Monday morning in the case of a weekend) of any non-compliance or a halt of any site mobilization, ground disturbance, grading, construction, and operation activities. The project owner shall notify the CPM of the circumstances and actions being taken to resolve the problem within one (1) working day of initiating the corrective action.

Whenever corrective action is taken by the project owner, a determination of success or failure would be made by the CPM within five working days after receipt of notice that corrective action is completed, or the project owner would be notified by the CPM that coordination with other agencies would require additional time before a determination can be made.

BIOLOGICAL RESOURCES WORKER ENVIRONMENTAL AWARENESS PROGRAM (WEAP)

BIO-5 The project owner shall develop and implement HBEP-specific Worker Environmental Awareness Program (WEAP) and shall secure approval for the WEAP from the CPM in consultation with USFWS and CDFW. The WEAP shall be administered to all onsite personnel including surveyors, construction engineers, employees, contractors, contractor's employees, supervisors, inspectors, and subcontractors. The WEAP shall be implemented during site mobilization, ground disturbance, grading, construction, operation, and closure. The WEAP shall:

1. Be developed by or in consultation with the Designated Biologist and consist of an on-site or training center presentation in which supporting electronic media and 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, explain the reasons for protecting these resources, and the function of flagging in designating sensitive resources and authorized work areas;

3. Discuss federal and state laws afforded to protect the sensitive species and explain penalties for violation of applicable laws, ordinances, regulations, and standards (e.g., federal, and state endangered species acts);

4. Place special emphasis on the light-footed ~~clapper~~ **Ridgway's** rail, western snowy plover, California least tern and Belding's savannah sparrow, including information on physical characteristics, distribution, behavior, ecology, sensitivity to human activities, legal protection and status, penalties for violations, reporting requirements, and protection measures;

5. Include a discussion of fire prevention measures to be implemented by workers during project activities; request workers to dispose of cigarettes and cigars appropriately and not leave them on the ground or buried;

6. Include a discussion of the biological resources conditions of certification;
7. Identify whom to contact if there are further comments and questions about the material discussed in the program; and
8. Include a training acknowledgment form to be signed by each worker indicating that they received the WEAP training and shall abide by the guidelines.

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

Verification: At least 45 days prior to the start of any project-related site disturbance activities, the project owner shall provide to the CPM a copy of the draft WEAP and all supporting written materials and electronic media prepared or reviewed by the Designated Biologist and a resume of the person(s) administering the program. The Notice to Proceed will not be issued until the WEAP has been approved by the CPM.

The project owner shall provide in the monthly compliance reports 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.

Throughout the life of the project, WEAP **training** shall be repeated annually for permanent employees, and shall be routinely administered within one week of arrival to any new personnel, foremen, contractors, subcontractors, and other personnel potentially working within the project area. Upon completion of the orientation, employees shall sign a form stating that they attend the program and understand all protection measures. These forms shall be maintained by the project owner and shall be made available to the CMP upon request. Workers shall receive and be required to visibly display a hardhat sticker or certificate indicating that they have completed the required training.

Training acknowledgement forms signed during construction shall be kept on file by the project owner for at least six months after the completion of all project construction activities. During project operation, signed statements for operational personnel shall be kept on file for six months following the termination of an individual's employment.

In the absence of comments, the CPM shall deem the WEAP acceptable to USFWS and/or CDFW.

BIOLOGICAL RESOURCES MITIGATION IMPLEMENTATION AND MONITORING PLAN (BRMIMP)

BIO-6 The project owner shall develop a BRMIMP and submit two copies of the proposed BRMIMP to the CPM for review and approval and to CDFW and USFWS for review and comment and shall implement the measures identified in the approved BRMIMP. The BRMIMP shall be prepared in consultation with the Designated Biologist and shall include the following:

1. All biological resource mitigation, monitoring, and compliance measures proposed and whether the project owner has agreed to the proposed measures;

2. All biological resource conditions of certification identified in the Commission Decision as necessary to avoid or mitigate impacts;

3. All biological resource mitigation, monitoring, and compliance measures required in other state agency terms and conditions, such as those provided in the National Pollution Discharge Elimination System (NPDES) Construction Activities Stormwater General Permit;

4. A list or tabulation of all sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation, and closure;

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

6. A detailed description of measures that shall be taken to avoid or mitigate disturbances from construction and demolition activities;

7. All locations, shown on a map at an approved scale, of sensitive biological resource areas subject to disturbance and areas requiring temporary protection and avoidance during construction;

8. Aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities prior to any site or related facilities mobilization disturbance, for comparison with aerial photographs at the same scale to be provided and subsequent to completion of project construction (see Verification).

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

10. Performance standards from each biological resource condition of certification to determine if mitigation and conditions are or are not successful;

11. Remedial measures to be implemented if performance standards are not met;

12. A discussion of biological resources-related facility closure measures including a description of funding mechanism(s);

13. A process for proposing BRMIMP modifications to the CPM and appropriate agencies for review and approval; and

14. A requirement to submit any sightings of any special-status species that are observed on or in proximity to the project site, or during project surveys, to the California Natural Diversity Database (CNDDB) per CDFW requirements.

Verification: No fewer than 45 days prior to planned start of construction, the project owner will submit a draft BRMIMP to the CPM for review and approval and to CDFW and USFWS for review and comment. The Notice to Proceed will not be issued until the BRMIMP has been approved by the CPM. In the absence of comments, the CPM shall deem the BRMIMP acceptable to USFWS and/or CDFW.

If the National Pollution Discharge Elimination System (NPDES) Construction Activities Stormwater General Permit or any other permits ~~has not~~ have not yet been received when the BRMIMP is first submitted, those permits shall be submitted to the CPM, the CDFW, and USFWS within 5 days of their receipt, and the BRMIMP shall be revised or supplemented to reflect the permit conditions, if any.

Prior to implementing any changes to the approved BRMIMP, the project owner shall provide a draft of the proposed modification to the CPM for review and approval and to CDFW and USFWS for review and comment. No modification shall be implemented until approved by the CPM. In the absence of comments, the CPM shall deem the modification to the BRMIMP acceptable to USFWS and/or CDFW.

Implementation of all BRMIMP measures shall be reported in the monthly compliance reports by the Designated Biologist (i.e., survey results, construction activities that were monitored, species observed). Within 30 days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written construction closure 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. The Construction Closure Report will include a set of aerial photographs of the site at an approved scale for comparison with the pre-construction set (Item 8 above).

GENERAL IMPACT AVOIDANCE AND MINIMIZATION MEASURES

BIO-7 The project owner shall implement the following measures during site mobilization, construction, operation, and closure to manage their project site and related facilities in a manner to avoid or minimize impacts to biological resources:

1. The boundaries of all areas to be temporarily or permanently disturbed (including staging areas, access roads, and sites for temporary placement of spoils) shall be delineated with stakes and flagging prior to construction activities in consultation with the Designated Biologist. Spoils shall be stockpiled in disturbed areas which do not provide habitat for special-status species. Parking areas, staging and disposal site locations shall similarly be located in areas without native vegetation or special-status species habitat. All disturbances, vehicles, and equipment shall be confined to the flagged areas.

2. At the end of each work day, the Designated Biologist, Biological Monitor, and/or site personnel shall ensure that all potential wildlife pitfalls (trenches, bores, and other excavations) have been backfilled. If site personnel are inspecting trenches, bores, and other excavations and wildlife is trapped, they will immediately notify the Designated Biologist and/or Biological Monitor. If backfilling is not feasible, all trenches, bores, and other excavations shall be sloped at a 3:1 ratio at the ends to provide wildlife escape ramps, or covered completely to prevent wildlife access. Should wildlife become trapped, the Designated Biologist or Biological Monitor shall remove and relocate the individual to a safe location. Any wildlife encountered during the course of construction shall be allowed to leave the construction area unharmed.

3. Transmission lines and all electrical components shall be designed, installed, and maintained in accordance with the Avian Power Line Interaction Committee's (APLIC's) Suggested P*ractices for Avian Protection on Power Lines* (APLIC 2006) and *Reducing Avian Collisions with Power Lines* (APLIC 2012) to reduce the likelihood of large bird electrocutions and collisions.

4. Spoils shall not be stockpiled adjacent to the southeastern fence line to minimize potential for spoils to enter into adjacent wetlands.

5. Soil bonding and weighting agents used on unpaved surfaces shall be non-toxic to wildlife and plants.

6. To the extent feasible, FAA visibility lighting shall employ only strobed, strobe-like, or blinking incandescent lights, preferably with all lights illuminating simultaneously. Minimum intensity, maximum "off-phased" duel strobes are preferred, and no steady burning lights (e.g., L-810s) shall be used.

7. Water applied to dirt roads and construction areas (trenches or spoil piles) for dust abatement shall use the minimal amount needed to meet safety and air quality standards in an effort to prevent the formation of puddles, which could attract California least tern predators to construction sites. During construction, site personnel shall patrol these areas to ensure water does not puddle and attract crows and other wildlife to the site, and shall take appropriate action to reduce water application rates where necessary.

8. During construction, each employee shall report on-site deaths, including road kill, and injuries of special-status species to the project's onsite environmental compliance manager immediately upon discovery. The project's onsite environmental compliance manager shall remove the carcass or injured animal promptly. The project's onsite environmental compliance manager shall immediately report any dead or injured special-status species to CDFW and/or USFWS and the CPM, and the project owner shall follow instructions that are provided by CDFW or USFWS. The project's onsite environmental compliance manager shall maintain a record of all dead or injured special-status species, including species name, physical characteristics of the animal (sex, age class, length, weight), disposition of the animal, and other pertinent information and shall include this information in the MCR.

   During operations, each employee shall report all deaths, including road kill, and injuries of special-status species to the Project Environmental Compliance Monitor immediately upon discovery~~. shall be notified~~. The Project Environmental Compliance Monitor shall remove the carcass or injured animal promptly. The Project Environmental Compliance Monitor shall immediately report any dead or injured special-status species to CDFW and/or USFWS and the CPM, and the project owner shall follow instructions that are provided by CDFW or USFWS. The Project Environmental Compliance Monitor shall maintain a record of all dead or injured special-status species, including species name, physical characteristics of the animal (sex, age class, length, and weight), disposition of the animal, and other pertinent information.

9. All vehicles and equipment shall be maintained in proper working condition to minimize the potential for fugitive emissions of motor oil, antifreeze, hydraulic fluid, grease, or other hazardous materials. The Designated Biologist shall be informed of any hazardous spills immediately as directed in the project Hazardous Materials Plan (see Condition of Certification HAZ-2). Hazardous spills shall be immediately cleaned up and the contaminated soil will be properly disposed of at a licensed facility. Any on-site servicing of vehicles or construction equipment shall take place only at a designated area approved by the Designated Biologist. Service/maintenance vehicles shall carry a bucket and pads to absorb leaks or spills.

10. During construction all trash and food-related waste shall be placed in self-closing containers and removed weekly or more frequently from the site. Workers shall not feed wildlife or bring pets to the project site.

11. Except for law enforcement personnel, no workers or visitors to the site shall bring firearms or weapons.

12. The project owner shall implement the following measures during construction and operation to prevent the spread and propagation of nonnative, invasive weeds:

a. Limit the size of any vegetation and/or ground disturbance to the minimum area needed for safe completion of project activities, and limit ingress and egress to defined routes;

b. Use only weed-free straw, hay bales, and seed for erosion control and sediment barrier installations. Invasive non-native species shall not be used in landscaping plans and erosion control. Monitor and rapidly implement control measures to ensure early detection and eradication of weed invasions.

13. During construction and operation, the project owner shall conduct pesticide management in accordance with standard BMPs. The BMPs shall include non-point source pollution control measures. The project owner shall use a licensed herbicide applicator and obtain recommendations for herbicide use from a licensed Pest Control Advisor. Herbicide applications must follow EPA label instructions. Minimize use of rodenticides and herbicides in the project area and prohibit the use of chemicals and pesticides known to cause harm to non-target plants and wildlife. The project owner shall only use pesticides for which a “no effect” determination has been issued by the EPA’s Endangered Species Protection Program for any species likely to occur within the project area or adjacent wetlands. If rodent control must be conducted, zinc phosphide or an equivalent product shall be used.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP and implemented. implementation of the measures shall be reported in the monthly compliance reports by the designated biologist. within 30 days after completion of project construction, the project owner shall provide to the cpm, for review and approval, a written construction completion report identifying how measures have been completed (see condition of certification bio-6 verification).

Monthly and annual compliance reports will include results of all regular inspections by the Designated Biologist and Biological Monitor(s), including but not limited to the requirements cited above and in condition of certification BIO-2.

The project owner must maintain written records of vehicle and equipment inspection and maintenance, and provide summaries in each monthly and annual compliance report. The complete written vehicle maintenance record will be available for the CPM’s inspection during normal business hours.

The BRMIMP (condition of certification BIO-6) must include affirmation by the project owner that:

- All electrical component design conforms to applicable APLIC guidelines; and
- All soil binders conform to the requirements stated above.

PRE-CONSTRUCTION NEST SURVEYS AND IMPACT AVOIDANCE AND MINIMIZATION MEASURES FOR BREEDING BIRDS

BIO-8 Pre-construction nest surveys shall be conducted if construction or demolition activities will occur from February 1 through August 31. The Designated Biologist or Biological Monitor shall perform surveys in accordance with the following guidelines:

1. Surveys shall cover all potential nesting habitat and substrate within the project site and areas surrounding the project site within 300 feet of the project boundary.

2. At least two pre-construction surveys shall be conducted, separated by a minimum 10-day interval. Pre-construction surveys shall be conducted no more than 14 days prior to initiation of construction activity. One survey needs to be conducted within the 3-day period preceding initiation of construction activity. Additional follow-up surveys may be required if periods of construction inactivity exceed three weeks in any given area, an interval during which birds may establish a nesting territory and initiate egg laying and incubation.

3. If active nests are detected during the survey, a no-disturbance buffer zone (protected area surrounding the nest) shall be established around each nest. Specific buffer distances are provided below for applicable avian groups (Biological Resources Table 1); these buffers may be modified with CPM's approval. For special-status species, if an active nest is identified, the size of each buffer zone shall be determined by the Designated Biologist in consultation with the CPM (in coordination with CDFW and USFWS). Nest locations shall be mapped using GPS technology.

Biological Resources Table 1:
HBEP Construction and Demolition Buffers for Active Nests

Avian Group	Species Potentially Nesting in the Project Vicinity	Buffer for Construction and Demolition Activities (feet)
Bitterns and herons	Black-crowned night heron, great blue heron, great egret, green heron, snowy egret	250
Cormorants	Double-crested cormorant	100
Doves	Mourning dove	25
Geese and ducks	American widgeon, blue-winged teal, cinnamon teal, Canada goose, gadwall, mallard, northern pintail, ruddy duck	100
Grebes	Clark's grebe, eared grebe, horned grebe, pied-billed grebe, western grebe	100
Hummingbirds	Allen's hummingbird, Anna's hummingbird, black-chinned hummingbird	25
Plovers	Black-bellied plover, killdeer	50
Raptors (Category 1)	American kestrel, barn owl, red-tailed hawk	50

Avian Group	Species Potentially Nesting in the Project Vicinity	Buffer for Construction and Demolition Activities (feet)
Raptors (Category 2)	Cooper's hawk, red-shouldered hawk, sharp-shinned hawk	150
Raptors (Category 3)	Northern harrier, white-tailed kite	These are special-status species; buffer determined in consultation with CPM
Stilts and Avocets	American avocet, black-necked stilt	150
Terns	Elegant tern, Forster's tern, royal tern	100
Passerines (cavity and crevice nesters)	House wren, Say's phoebe, western bluebird	25
Passerines (bridge, culvert, and building nesters)	Black phoebe, cliff swallow, house finch, Say's phoebe	25
Passerines (ground nesters, open habitats)	Horned lark	100
Passerines (understory and thicket nesters)	American goldfinch, blue-gray gnatcatcher, bushtit, California towhee, common yellowthroat, red-winged blackbird, song sparrow, Swainson's thrush	25
Passerines (scrub and tree nesters)	American crow, American goldfinch, American robin, blue-gray gnatcatcher, Bullock's oriole, bushtit, Cassin's kingbird, common raven, hooded oriole, house finch, lesser goldfinch, northern mockingbird	25
Passerines (tower nesters)	Common raven, house finch	25
Passerines (marsh nesters)	Common yellowthroat, red-winged blackbird	25
Species not covered under MBTA	Domestic waterfowl, including domesticated mallards, feral (rock) pigeon, European starling, and house sparrow	N/A

4. If active nests are detected during the survey, the Designated Biologist or Biological Monitor shall monitor all nests with buffers at least once per week, to determine whether birds are being disturbed. If signs of disturbance or distress are observed, the Designated Biologist or Biological Monitor shall immediately implement adaptive measures to reduce disturbance in coordination with the CPM. These measures could include, but are not limited to, increasing buffer size, halting disruptive construction activities in the vicinity of the nest until fledging is confirmed, or placement of visual screens or sound dampening structures between the nest and construction activity.

5. If active nests are detected during the survey, the Designated Biologist or Biological Monitor shall monitor the nest until he or she determines that nestlings have fledged and dispersed or the nest is no longer active. Activities that might, in the opinion of the Designated Biologist or Biological Monitor, disturb nesting activities (e.g., exposure to exhaust), shall be prohibited within the buffer zone until such a determination is made.

6. A qualified biologist shall conduct a habitat assessment for light-footed ~~clapper~~ **Ridgway's** rail ~~shall be conducted~~ in Magnolia and Upper Magnolia Marshes during the breeding season (March 1 to August 1) immediately preceding the commencement of construction and demolition activities. If suitable breeding habitat for the light footed ~~clapper~~ **Ridgway's** rail is identified, focused surveys will be conducted prior to any construction or demolition activities. Surveys are not required if no suitable habitat is present. If ~~clapper~~ **Ridgway's** rails are detected during the breeding season, the CPM, CDFW, and USFWS will be notified and the project owner will consult with the USFWS for incidental take authorization, if required.

Verification: The project owner shall provide notification to the CPM, CDFW, and USFWS at least 2 weeks prior to initiating the habitat assessment and any subsequent surveys for light-footed ~~clapper~~ **Ridgway's** rail; notification will include the name and resume of the biologist(s) conducting the habitat assessment and surveys and the timing of the surveys. Within ten (10) days of completion of the field work, the project owner shall provide the CPM, CDFW, and USFWS a report describing the findings of the preconstruction nest surveys and the light-footed ~~clapper~~ **Ridgway's** rail habitat assessment and focused survey (if surveys were conducted), including a description and representative photographs of habitat in the marshes; the time, date, methods, and duration of the surveys; identity and qualifications of the surveyor(s); and a list of species observed. If active nests are detected during the surveys, the reports shall include a map or aerial photo identifying the location of the nest(s) and shall depict the boundaries of the proposed no disturbance buffer zone around the nest(s). The CPM will consider any timely comments received from CDFW and USFWS in review of the report. In the absence of comments within that timeframe, the CPM shall deem the report acceptable to USFWS and/or CDFW.

Additionally, the nest monitoring plan shall be submitted to the CPM for review and approval and to USFWS and CDFW for review and comment prior to any planned demolition or construction activities in the vicinity of any active nest. No such demolition or construction activities may proceed without CPM approval of the nest monitoring plan. If light-footed ~~clapper~~ **Ridgway's** rails are documented during the breeding season in Upper Magnolia or Magnolia Marshes, prior to any planned pile driving on the site or demolition or construction activities within 400 feet of the marsh boundary, the project owner will notify the CPM and will consult with the USFWS for incidental take authorization or a determination that no incidental take authorization is required. All impact avoidance and minimization measures related to nesting birds shall be included in the BRMIMP and implemented. In the absence of comments within that timeframe, the CPM shall deem the nest monitoring plan acceptable to USFWS and/or CDFW. Implementation of the measures shall be reported in the monthly compliance reports by the Designated Biologist.

REFERENCES

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

Chesser T.R., R.C. Banks, C. Cicero, J.L. Dunn, A.W. Kratter, I.J. Lovette, A.G. Navarro-Sigüenza, P.C. Rasmussen, J.V. Remsen, Jr., J.D. Rising, D.F. Stotz, and K. Winker. 2014. Fifty-Fifth Supplement to the American Ornithologists' Union *Check-list of North American Birds*. The Auk: October 2014, Vol. 131, No. 4, pp. CSi-CSxv.

R. Zembal, Hoffman, S.M., and J. Konecny 2015. Status and Distribution of the Light-footed Ridgway's (Clapper) Rail in California- 2015 Season. CA Department of Fish and Game, Nongame Wildlife Unit Report, 2015-04. Page 4.

Smith, G. 2016. Gordon Smith. Chairman, Huntington Beach Wetlands Conservancy. Personal communication to Tim Singer (California Energy Commission staff) and Heather Blair (Aspen Environmental Group consultant). February 18th, 2016.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)

Petition to Amend Final Commission Decision

CULTURAL RESOURCES

Melissa Mourkas and Gabriel Roark

SUMMARY OF CONCLUSIONS

Staff concludes that proposed amendment would not result in new significant environmental effects, or increase the severity of previously identified significant effects. No known, significant cultural resources (that is, historical resources, unique archaeological resources, or tribal cultural resources) have been identified in the Amended Huntington Beach Energy Project's (HBEP) project area of analysis. Similar to the Licensed HBEP, construction of the project as amended could result in impacts on buried, as-yet-unidentified cultural resources. However, the amended project components appear consistent with the scale of excavation described for the licensed project. Staff therefore concludes that existing conditions of certification (Conditions) **CUL-1–8** for the HBEP are sufficient to reduce the severity of any inadvertent impacts on buried cultural resources to less than significant. Thus, in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162, staff concludes that no supplementation to the California Energy Commission Final Decision (Decision) for the HBEP is necessary for Cultural Resources. Staff also finds that the amended project would conform to applicable laws, ordinances, regulations, and standards (LORS) relevant to cultural resources.

INTRODUCTION

The Petition to Amend (PTA) proposes the following activities which have the potential to impact cultural resources and were not analyzed in the HBEP licensing proceeding or the Decision (CEC 2014a).

- Inclusion of the nearly 30-acre Plains All American Tank Farm (tank farm) for construction laydown and parking;
- Creation of a new entrance to the tank farm site with an approximately 35–40-feet-by-150-feet entrance road;
- Removal of vegetation and portions of the earthen berm that surrounds the tank farm to accommodate the new entrance road;
- Rearrangement of the proposed project elements within the project site that may affect depth of excavation and site grading.

Staff has reviewed the PTA for potential environmental effects and consistency with applicable LORS. In completing this analysis, cultural resources staff analyzed the following:

1. The extent of proposed modifications;

2. The proposed modifications' potential to significantly affect the environment;

3. The project's compliance with all applicable LORS, should the Energy Commission approve the proposed modifications;

4. The need to change or delete an existing license condition in light of the proposed modifications. (Cal. Code Regs., tit. 20, §1769[a][2].)

SUMMARY OF THE DECISION

Concerning cultural resources, the Decision concluded that the project owner will implement a cultural resources monitoring and mitigation program for response to inadvertent discoveries of cultural resources; there is no evidence that the HBEP would have a cumulatively considerable incremental effect on cultural resources in conjunction with other projects in the area; the Huntington Beach Generating Station (HBGS) is not an historical resource for the purposes of CEQA; the Decision's Conditions (**CUL-1–8**) would ensure compliance with applicable LORS; and the mitigation measures contained in the conditions will ensure that any project impacts on cultural resources would be reduced to a less-than-significant level (CEC 2014a:5.3-10–5.3-11, Appendix A).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The LORS applicable to cultural resources in the project vicinity have not changed since adoption of the Decision (CEC 2014a: Cultural Resources Table 1). A Draft Historic and Cultural Resources Element (HCRE) (Galvin 2014a) for the Huntington Beach General Plan has been written and circulated for public comment. An updated landmarks list has been prepared as part of the new Historic Context and Survey Report (Galvin 2014b). This draft HCRE removes the HBGS from the landmarks list and is in conformance with the Decision's findings that the HBGS is not an historical resource for the purpose of CEQA nor does its demolition create a conflict with local LORS.

ENVIRONMENTAL IMPACT ANALYSIS

This section of the cultural resources analysis addresses the proposed modifications' potential to affect the cultural resources environment. It begins with a discussion of the regulatory context for evaluating impacts and follows with a description of staff's cultural resources (or historical resources) inventory and analysis of the PTA.

REGULATORY CONTEXT

Various laws apply to the evaluation and treatment of cultural resources. CEQA requires the Energy Commission to evaluate cultural resources by determining whether they meet several sets of specified criteria. These evaluations then influence the analysis of potential impacts to the resources and the mitigation that might be required to ameliorate any such impacts. In the Decision for the Licensed HBEP, the Energy Commission evaluated cultural resources according to CEQA's criteria for historical resources and unique archaeological resources, as well as the city of Huntington Beach's local landmarks register (CEC 2014a:5.3-1–5.3-2, 5.3-9–5.3-10). Since the Energy Commission approved the Licensed HBEP, CEQA and other portions of the California Public Resources Code were amended by Assembly Bill 52 (AB 52) to define "tribal cultural resources" effective July 1, 2015.

California Native American Tribes, Lead Agency Tribal Consultation Responsibilities, and Tribal Cultural Resources

AB 52 amended CEQA to define California Native American tribes, lead agency responsibilities to consult with California Native American tribes, and tribal cultural resources. "California Native American tribe" means a "Native American tribe located in California that is on the contact list maintained by the Native American Heritage Commission [NAHC] for the purposes of Chapter 905 of the Statutes of 2004" (Pub. Resources Code, § 21073). Lead agencies implementing CEQA are responsible to conduct tribal consultation with California Native American tribes about tribal cultural resources within specific time frames, observant of tribal confidentiality, and if tribal cultural resources could be impacted by project implementation, are to exhaust the consultation to points of agreement or termination.

Tribal cultural resources are either of the following:

1. Sites, features, places, cultural landscapes, sacred places, and objects with cultural value to a California Native American tribe that are either of the following.
    a. Included or determined to be eligible for inclusion in the California Register of Historical Resources (CRHR).
    b. Included in a local register of historical resources as defined in the Public Resources Code, section 5020.1(k).
2. A resource determined by the lead agency, in its discretion and supported by substantial evidence, to be significant pursuant to criteria set forth in the Public Resources Code, section 5024.1(c). In applying the aforesaid criteria, the lead agency shall consider the significance of the resource to a California Native American tribe. (Pub. Resources Code, § 21074[a].)

A cultural landscape that meets the criteria of Public Resources Code, section 21074(a), is a tribal cultural resource to the extent that the landscape is geographically defined in terms of its size and scope (Pub. Resources Code, § 21074[b]).

Historical resources, unique archaeological resources, and non-unique archaeological resources, as defined at Public Resources Code, sections 21084.1, 21083.2(g), and 21083.2(h) may also be a tribal cultural resource if they conform to the criteria of Public Resources Code, section 21074[a], two paragraphs above.

This section of the Preliminary Staff Assessment of the PTA, therefore, assesses the proposed amendment's impacts on historical resources, unique archaeological resources, and tribal cultural resources.

AB 52 also amended CEQA to state that a project with an impact that may cause a substantial adverse change in the significance of a tribal cultural resource is a project that may have a significant effect on the environment (Pub. Resources Code, § 21084.2).

CULTURAL RESOURCES INVENTORY

The development of an inventory of cultural resources in and near the project area of analysis (PAA) is the requisite first step in the assessment of whether the project might, under Public Resources Code, section 21084.1, cause a substantial adverse change in the significance of a historical resource, unique archaeological resource, or tribal cultural resource, and could, therefore, have a significant effect on the environment. The effort to develop the inventory has involved conducting a sequence of investigatory phases that includes doing background research, interpreting the results of the inventory effort as a whole, and evaluating whether found cultural resources are historically significant. This section discusses the methods and the results of each inventory phase, develops the cultural resources inventory for the analysis of the proposed amendment, and interprets the inventory to assess how well it represents the cultural resources of the PAA.

Project Area of Analysis

The PAA is a concept that staff uses to define the geographic area in which the proposed project has the potential to affect cultural resources. The effects that a project may have on cultural resources may be immediate, further removed in time, or cumulative. They may be physical, visual, auditory, or olfactory in character. The geographic area that would encompass consideration of all such effects may or may not be one uninterrupted expanse. It may include the project area, which would be the site of the proposed plant (project site), the routes of requisite transmission lines and water and natural gas pipelines, and other offsite ancillary facilities, in addition to one or several discontiguous areas where the project could be argued to potentially affect cultural resources.

For the Amended HBEP, staff defines the PAA as comprising (a) the proposed project site; (b) an architectural study area set approximately one parcel beyond the proposed project site; (c) the onsite construction parking area; (d) four off-site construction parking areas; (e) the off-site construction laydown area at the Alamitos Generating Station in Long Beach, Los Angeles County; (f) the construction parking and laydown area at the Plains All American Tank Farm; and (g) the area that would be affected by improvements to the Magnolia Street–Banning Avenue intersection.

Staff further defines the archaeological PAA as comprising the locations of proposed project modifications, in both their horizontal and vertical dimensions. Review of the PTA and the project owner's responses to staff data requests suggests that the majority of project components on the existing HBGS property would require excavation to depths of 5.00–5.75 feet below ground surface (AES 2015a:2-2–2-4, 2-8, 2-10–2-12, 2-14; AES 2015b:24–27). These depths and the locations of these project components are similar to those of the Licensed HBEP (see CEC 2014b:4.3-31–4.3-32). Nonetheless, staff is lacking excavation information on five project components proposed on the HBGS property. Additionally, staff must consider the potential impacts of excavation work at the Plains All American Tank Farm, which is slated for use as an offsite laydown area as part of the proposed amendment. These eight components of the proposed amendment are summarized in **Cultural Resources Table 1**.

For ethnographic resources, the PAA is expanded to take into account sacred sites, traditional cultural properties (places), and larger areas such as ethnographic landscapes that can be vast and encompassing, including viewsheds that contribute to the historical significance of such historical resources. For the proposed amendment, staff identified no ethnographic resources and so defined no area of analysis for them.

Cultural Resources Table 1
Depth of Excavation by Amended Project Component

Project Activity	Maximum Depth of Excavation (ft)	References
Two new gas metering stations	Unknown	AES 2015a:2-8; AES 2015b:25
Wastewater discharge pipeline	Unknown	AES 2015a:2-4; AES 2015b:26
Demolish existing natural gas metering station	Unknown	AES 2015a:2-8; AES 2015b:25
Atmospheric flash tank	Unknown	AES 2015a:2-10
New 650,000-gal, onsite fire/service WST	Unknown	AES 2015a:2-11
Vegetation removal at PAM	Unknown	AES 2015a:5.2-2; AES 2015b:27; Fowler 2015
Excavate new entrance to PAM	2–3	AES 2015a:5.2-2; AES 2015b:27; Fowler 2015
Reconfigure Magnolia St–Banning Ave intersection	2–3	AES 2015a:2-14; AES 2015b:27;
Abbreviations: AES = AES Southland Development; Ave = Avenue; ft = foot or feet; gal = gallon; PAM = Plains All American Tank Farm; St = Street; WST = water storage tank		

Background Research

The background research for the present analysis employs information that the petitioner and Energy Commission staff gathered from literature and record searches, as well as documents from the Licensed HBEP. The purpose of the background information is to help formulate the initial cultural resources inventory for the present analysis, to identify information gaps, and to inform the design and the interpretation of the field research that will serve to complete the inventory.

Literature Review and Records Search

The literature review and records search attempts to gather and interpret documentary evidence of the known cultural resources in the PAA. The source for the present search was the South Central Coastal Information Center (SCCIC) of the California Historical Resources Information System (CHRIS).

Methods and Results

A total of 15 cultural resources studies have previously been conducted in the PAA (see **Cultural Resources Appendix A, Table A1**). The entire archaeological portion of the PAA had recently been surveyed for the presence of cultural resources, with the exception of the former Plains All American Tank Farm, which was last surveyed 43 years ago (Hoover 2000:6). An additional 28 cultural resources studies have previously been conducted within 1 mile of the PAA (see **Cultural Resources Appendix A, Table A2**).

The records search indicates that one cultural resource, the HBGS (P-30-176946), has previously been recorded in the project site, whereas six cultural resources have previously been recorded within the records search area (**Cultural Resources Appendix A, Table A3**). The Energy Commission determined that the HBGS is not an historical resource for the purposes of CEQA during the Licensed HBEP proceeding (CEC 2014a:5.3-10).

Additional Literature Review

Staff conducted additional research at the Energy Commission in-house library, the California State Library, and online sources, as well as consulted the reports contained in the project owner's records search. The purpose of this research was to obtain an understanding of the natural and cultural development of the land in and around the PAA, identify locations of potential cultural resources, and have a partial, chronological record of disturbances in the PAA. All consulted historic maps are presented in **Cultural Resources Appendix A** (**Table A3**).

Archaeological Survey

On July 9, 2015, CH2MHill archaeologist, Natalie Lawson, surveyed the Plains All American Tank Farm addition to the proposed amendment on behalf of the project owner. The PTA does not describe Ms. Lawson's survey methods. (AES 2015a:5.3-2.) In response to staff Data Request A49, the project owner offered this explanation of Ms. Lawson's survey methods: "The cultural resources survey of the Plains All American Tank Farm was conducted on September 28, 2011[1], by Natalie Lawson…field survey included all of the proposed disturbance area as well as a 200-foot-minimum buffer around the proposed disturbance area. The surveyed area was covered in 10-meter-wide transects" (AES 2015b:30). No archaeological resources were identified as a result of the survey (AES 2015a:5.3-3).

Tribal Consultation

A check of the NAHC sacred lands files resulted in negative findings within one-half mile radius of the proposed project. Staff sent letters to all of the NAHC-listed tribes for the project vicinity, inviting them to comment on the proposed project and offered to hold face-to-face consultation meetings if any tribal entities so requested. Staff received comments from the Juaneño Band of Mission Indians, Acjachemen Nation, and Gabrielino-Tongva Tribe that tribal monitors should be required during project ground disturbing activities. A letter from the United Coalition to Protect Panhe stated concern that the project site is culturally sensitive and encouraged staff to promote avoidance as mitigation for any cultural resource discoveries connected with the proposed project. Provisions for avoidance and monitoring are contained in conditions **CUL-6** and **CUL-7**.

Archaeological and Tribal Cultural Resources in the One-Mile Radius

The project owner's updated records search did not identify any additional cultural resources in the Amended HBEP's records search area (AES 2015a:5.3-2). Of the six previously recorded resources identified in the records search area, four are archaeological resources and one is a natural shell accumulation that was recorded as a prehistoric archaeological site (**Cultural Resources Appendix A, Table A3**). The Amended HBEP would not affect these resources, and they will not be discussed further in this analysis.

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[1] CH2MHill archaeologist, Gloriella Cardenas, surveyed the Licensed HBEP project area. Ms. Cardenas's survey area included a small (about 1.4-acre) offsite parking area and a 200-foot buffer surrounding it. The parking area and buffer intersected a portion of the Plains All American Tank Farm. (AES 2012:5.3-19, Figure 5.3-1). Staff assumes that the project owner meant to identify Ms. Cardenas as having surveyed a portion of the tank farm property on July 28, 2011, while Ms. Lawson surveyed the balance of the tank farm on July 9, 2015.

Potential Impacts

Staff has been unable to determine the depth of excavation required to build the first five amended project elements listed in **Cultural Resources Table 1**, all of which would be built on the HBGS property. These project elements are similar to others proposed under the Licensed HBEP and their proposed installation would, like the bulk of the Licensed HBEP, occur primarily in artificial fill sediments. Under these conditions, as-yet-unidentified, buried cultural resources would potentially occur within the bottom 0.5–2.0 feet (about 7.5 feet below the present ground surface) of proposed excavations (excepting foundation piles). Based on the Final Decision and in the lack of new evidence to the contrary, staff concludes that the potential cultural resources impacts of the two new gas metering stations, wastewater discharge pipeline, demolition of the existing natural gas metering station, installation of the atmospheric flash tank, and construction of a new 650,000-gallon, onsite fire/service water storage tank would be similar to impacts already analyzed; that is, there is the potential for construction to encounter buried archaeological resources. Conditions **CUL-1–8**, as licensed, would reduce the severity of such impacts to a less-than-significant level (CEC 2014a:5.3-7, 5.3-10).

Excavation entailed in the proposed excavation of new entrance to the Plains All American Tank Farm and reconfiguration of the Magnolia Street–Banning Avenue intersection would require 2–3 feet of excavation below ground surface—within fill and reworked sediments. These excavations would be unlikely to encounter and damage buried cultural resources. In the event that such an inadvertent discovery occurred during road-building or intersection improvements, existing conditions **CUL-1–8** would reduce the severity of these impacts to a less-than-significant level.

The proposed vegetation removal from the southeastern berm, or Greenbelt—a prerequisite for building the new construction entrance to the Plains All American Tank Farm—is a less clear-cut case compared to the impacts analyzed in the previous two paragraphs. According to biologists working for MBC Applied Environmental Sciences, the Greenbelt was built up from sediments graded from the Plains All American Tank Farm property (MBC 2010:5). The tank farm property was built up between 1968 and 1973, according to historic aerial photographs and topographic maps; the Greenbelt appears to have been established by 1977 (EMS 2012: Appendix G). Removal of trees and other vegetation from the Greenbelt would primarily disturb the fill soils that were moved from the tank farm site, although removal of mature trees could result in disturbance of natural sediments. Conditions **CUL-1–8** for the Licensed HBEP require a cultural resources training and monitoring program that is sufficient to reduce the impacts of inadvertent archaeological discoveries to a less-than-significant level, should any occur during vegetation removal.

Built Environment Resources in the One-Mile Radius

The project modification proposal to include the Plains All American Tank Farm changes the built environment study area by adding the tank farm itself to the project and extending the one-parcel architectural study area to accommodate the revised footprint. The project owner completed a survey and evaluation of the tank farm and a windshield-level survey of a residential neighborhood on the east side of Magnolia Street in order to accommodate the proposed project changes.

Plains All American Tank Farm

The tank farm appears to have been built between 1963 and 1972. The nearly 30-acre site comprises three storage tanks, a pump house and a valve/manifold structure. It is surrounded by a vegetated earthen containment berm. Each tank is located within a shallow retention basin. The tank farm has been evaluated by the project owner for its potential significance as an historical resource under CEQA. The tank farm is utilitarian in nature and not known to be associated with any significant trends, persons or design styles in California history. Huntington Beach has an impressive history with the oil industry, which played a strong role in its development. The period of significance for the oil industry in Huntington Beach is characterized as 1920 to 1950 (Galvin 2014). The tank farm was constructed well after the oil boom and is unlikely to be of significance to Huntington Beach's development. Staff agrees with the project owner and recommends that the Plains All American Tank Farm does not appear to meet any of the criteria for significance that would make it eligible for listing on the CRHR.

Kiowa Lane Residences

The project owner included a windshield survey of a residential neighborhood that is one-parcel adjacent to the Plains All American Tank Farm, across Magnolia Street and fronting Kiowa Lane. The investigation revealed that the neighborhood was developed and constructed in 1965. The development is characterized as mid-century, single-story ranch and two-story homes with Asian and Tiki-inspired eaves and hipped roofline treatments (AES 2015a:5.3-3). Some have clay tile roofs with a Spanish-eclectic sensibility. Many have been remodeled over the years. While there may have been a cohesive development of similarly-styled homes at the outset in 1965, modifications made over time have substantially changed the setting, feeling, design, workmanship and materials of the neighborhood. Therefore, there exists no integrity to the period of significance of 1965. The homes along Kiowa Lane within the one-parcel boundary of the tank farm are not eligible individually or as a district for listing under any of the criteria for the CRHR and therefore not recommended as historical resources under CEQA.

Environmental Justice Impacts

As discussed in the Socioeconomics section of the PSA, there is neither a minority nor poverty-based environmental justice population residing within a 6-mile buffer of the HBEP. Relevant to cultural resources, staff reviewed the ethnographic and historical literature to determine whether any Native American populations use the project area. Staff concluded that because there is no current hunting or gathering area, Native Americans are not considered an environmental justice population for this project.

Cumulative Impacts

The HBEP Decision concluded that construction of the proposed HBEP would result in less-than-significant cumulative impacts on cultural resources; although construction of the proposed HBEP could result in damage to as-yet-unidentified, buried archaeological resources, the Decision includes eight conditions designed to mitigate any such inadvertent impacts. Therefore, the incremental effect of the proposed HBEP in conjunction with other projects will not be cumulatively considerable. (CEC 2014a:5.3-9.)

Since issuance of the Decision, additional projects have been built, proposed, and cancelled in the project vicinity, with varying degrees of cultural resources impacts. The amended HBEP, however, would not result in new or changed impacts on cultural resources; like the licensed HBEP, the amended HBEP's incremental effect would not be cumulatively considerable. Staff therefore concludes that the HBEP Decision does not require supplementation for cumulative impacts on cultural resources.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that no known historical resources, unique archaeological resources, or tribal cultural resources have been identified in the Amended PAA. As with the Licensed HBEP, however, construction of the Amended HBEP could result in impacts on buried, as-yet-unidentified cultural resources. Such impacts would most likely occur during construction of the project components for which the depth of excavation is unknown (see **Cultural Resources Table 1**); however, excavation to construct even these project components appear consistent with the scale of excavation described for the Licensed HBEP (that is, the project elements summarized in **Cultural Resources Table 1** are unlikely to require deeper excavations than what is already licensed). Staff therefore agrees with the project owner that existing license conditions **CUL-1–8** are sufficient to reduce the severity of any inadvertent impacts on buried cultural resources to a less than significant level. Staff also agrees that the Amended HBEP would conform to LORS relevant to cultural resources.

PROPOSED CONDITIONS OF CERTIFICATION

Staff proposes no modifications to the HBEP conditions of certification. Deleted text is in ~~strikethrough~~. New text is **<u>bold</u>** and **<u>underlined</u>**.

CUL-1 APPOINTMENT AND QUALIFICATIONS OF CULTURAL RESOURCES SPECIALIST (CRS)

A. CULTURAL RESOURCE SPECIALIST

1. Appointment and Qualifications

   The project owner shall assign at least one Cultural Resources Specialist (CRS) to the project. The project owner shall submit the resume of the proposed CRS, with at least three references and contact information, to the Energy Commission Compliance Project Manager (CPM) for review and approval.

   The CRS and alternate CRS(s) shall ~~include~~ have training and background that conform to the U.S. Secretary of the Interior's Professional Qualifications Standards, as published in Title 36, Code of Federal Regulations, part 61. In addition, the CRS and alternate CRS(s) shall have the following qualifications:

   a. A background in anthropology, archaeology, history, architectural history, or a related field;

b. At least 10 years of archaeological or historical experience (as appropriate for the project site), with resources mitigation and fieldwork;

c. At least one year of field experience in California; and

d. At least three years of experience in a **decision-making** capacity on cultural resources projects in California and the appropriate training and experience to knowledgably make recommendations regarding the significance of cultural resources.

The project owner may replace the CRS by submitting the required resume, references and contact information of the proposed replacement to the CPM.

2. Duties of Cultural Resources Specialist

The CRS shall manage all cultural resource monitoring, mitigation, curation, and reporting activities, and any post-certification cultural resource activities (as defined above), unless management of these is otherwise provided for in accordance with the cultural resource conditions of certification (conditions). The CRS shall serve as the primary point of contact on all cultural resource matters for the Energy Commission. The CRS may elect to obtain the services of Cultural Resource Monitors (CRMs), Native American Monitors (NAMs), and other technical specialists, if needed, to assist in monitoring, mitigation, and curation activities. The project owner shall ensure that the CRS makes recommendations regarding the eligibility for listing in the California Register of Historical Resources (CRHR) of any cultural resources that are newly discovered or that may be affected in an unanticipated manner.

After all ground disturbances is completed and the CRS has fulfilled all responsibilities specified in these cultural resources conditions, the project owner may discharge the CRS, after receiving approval from the CPM.

The **conditions of certification** described in this subsection of the FSA shall continue to apply during operation of the proposed power plant.

B. CULTURAL RESOURCES MONITORS

1. Appointment and Qualifications

The project owner may assign Cultural Resources Monitors (CRMs). CRMs shall have the following qualifications:

a. B.S. or B.A. degree in anthropology, archaeology, historical archaeology, or a related field; and one year of archaeological field experience in California; or

b. A.S. or A.A. degree in anthropology, archaeology, historical archaeology, or a related field, and four years of archaeological field experience in California; or

c. Enrollment in upper division classes pursuing a degree in the fields of anthropology, archaeology, historical archaeology, or a related field, and two years of archaeological field experience in California.

C. NATIVE AMERICAN MONITORS

1. Appointment and Qualifications:

If required pursuant to condition of certification **CUL-6**, the project owner shall obtain the services of qualified Native American Monitors (NAMs). Preference in selecting NAMs shall be given to Native Americans with:

a. Traditional ties to the area to be monitored, and

b. The highest qualifications as described by the Native American Heritage Commission (NAHC) document entitled: *Guidelines for Monitors/Consultants of Native American Cultural, Religious, and Burial Sites* (NAHC 2005).

Verification: The project owner shall submit the specified information at least 75 days prior to the start of (1) ground disturbance (as defined in the Compliance Conditions section); (2) post-certification cultural resources activities (including, but not limited to, "survey", "in-field data recording," "surface collection," "testing," "data recovery" or "geoarchaeology"); or (3) site preparation or subsurface soil work during pre-construction activities or site mobilization[2], the project owner shall obtain the services of a Cultural Resources Specialist (CRS) and one or more alternate CRS.

The project owner may replace a CRS by submitting the required resume, references and contact information to the CPM at least ten working days prior to the termination or release of the then-current CRS. In an emergency, the project owner shall immediately notify the CPM to discuss the qualifications and approval of a short-term replacement while a permanent CRS is proposed to the CPM for consideration.

At least 20 days prior to Cultural Resources Ground Disturbances, the CRS shall provide proof of qualifications for any anticipated CRMs and additional specialists for the project to the CPM.

At least 5 days prior to additional CRMs or NAMs beginning on-site duties during the project, the CRS shall review the qualifications of the proposed CRMs or NAMs and send approval letters to the CPM, identifying the monitors and attesting to their qualifications.

[2] For purposes of the Conditions of Certification for Cultural Resources, we will refer to these activities as "Cultural Resources Ground Disturbances".

At least 10 days prior to any technical specialists beginning tasks, the resume(s) of the specialists shall be provided to the CPM for review and approval.

At least 10 days prior to the start of construction-related ground disturbance, the project owner shall confirm in writing to the CPM that the approved CRS will be available for onsite work and is prepared to implement the cultural resources conditions.

No Cultural Resources Ground Disturbances shall occur prior to CPM approval of the CRS and alternates, unless such activities are specifically approved by the CPM.

CUL-2 INFORMATION TO BE PROVIDED TO CRS

Prior to the start of Cultural Resources Ground Disturbances , the project owner shall provide the CRS with copies of the AFC, data responses, confidential cultural resources reports, all supplements, the Energy Commission staff's cultural resources FSA, and the cultural resources Conditions of Certification from the Final Decision for the project if the CRS has not previously worked on the project. The project owner shall also provide the CRS and the CPM with maps and drawings showing the footprints of the power plant, all linear facility routes, all access roads, and all laydown areas. Maps shall include the appropriate USGS quadrangles and a map at an appropriate scale (e.g., 1:24,000 and 1 inch = 200 feet, respectively) for plotting cultural features or materials. If the CRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the CRS and CPM. The CPM shall review map submittals and, in consultation with the CRS, approve those that are appropriate for use in cultural resources planning activities. No ground disturbance shall occur prior to CPM approval of maps and drawings, unless such activities are specifically approved by the CPM.

Maps shall include any NRHP/CRHR-eligible historic built environment resources identified in the FSA.

If construction of the project would proceed in phases, maps and drawings not previously provided shall be provided to the CRS and CPM prior to the start of each phase. Written notice identifying the proposed schedule of each project phase shall be provided to the CRS and CPM.

Weekly, until ground disturbance is completed, the project construction manager shall provide to the CRS and CPM a schedule of project activities for the following week, including the identification of area(s) where ground disturbance will occur during that week.

The project owner shall notify the CRS and CPM of any changes to the scheduling of the construction phases.

The project owner shall provide the documents described in the first paragraph of this condition to new CRSs in the event that the approved CRS is terminated or resigns.

Verification:

1. At least 40 days prior to the start of ground disturbance, the project owner shall provide the CPM notice that the AFC, data responses, confidential cultural resources documents, all supplements, FSA, and Final Commission Decision have been provided to the CRS, if needed, and the subject maps and drawings to the CRS and CPM. The CPM will review submittals in consultation with the CRS and approve maps and drawings suitable for cultural resources planning activities.

2. At least 15 days prior to the start of ground disturbance, if there are changes to any project-related footprint, the project owner shall provide revised maps and drawings for the changes to the CRS and CPM.

3. At least 15 days prior to the start of each phase of a phased project, the project owner shall submit the appropriate maps and drawings, if not previously provided, to the CRS and CPM.

4. Weekly, during ground disturbance, a schedule of the next week's anticipated project activity shall be provided to the CRS and CPM by letter, e-mail, or fax.

5. Within 5 days of changing the scheduling of phases of a phased project, the project owner shall provide written notice of the changes to the CRS and CPM.

6. If a new CRS is approved by the CPM as provided for in **CUL-1**, the project owner shall provide the CPM notice that the AFC, data responses, confidential cultural resources documents, all supplements, FSA, Final Commission Decision, and maps and drawings have been provided to the new CRS within 10 days of such approval.

CUL-3 CULTURAL RESOURCES MITIGATION AND MONITORING PLAN (CRMMP)

Prior to the start of Cultural Resources Ground Disturbances, the project owner shall submit the Cultural Resources Mitigation and Monitoring Plan (CRMMP), as prepared by or under the direction of the CRS, to the CPM for review and approval. The CRMMP shall follow the content and organization of the draft model CRMMP, provided by the CPM, and the authors' name(s) shall appear on the title page of the CRMMP. The CRMMP shall identify measures to minimize potential impacts to sensitive cultural resources. Implementation of the CRMMP shall be the responsibility of the CRS and the project owner. Copies of the CRMMP shall reside with the CRS, alternate CRS, each CRM, and the project owner's on-site construction manager. No ground disturbance shall occur prior to CPM approval of the CRMMP, unless such activities are specifically approved by the CPM. The CRMMP shall be designated as a confidential document if the location(s) of cultural resources are described or mapped.

The CRMMP shall include, but not be limited to, the following elements and measures:

1. The following statement included in the Introduction: “Any discussion, summary, or paraphrasing of the conditions of certification in this CRMMP is intended as general guidance and as an aid to the user in understanding the conditions and their implementation. The conditions, as written in the Commission Decision, shall supersede any summarization, description, or interpretation of the conditions in the CRMMP. The Cultural Resources conditions of certification from the Commission Decision are contained in Appendix A.”

2. A proposed general research design that includes a discussion of archaeological research questions and testable hypotheses specifically applicable to the project area, and a discussion of artifact collection, retention/disposal, and curation policies as related to the research questions formulated in the research design. The research design shall specify that the preferred treatment strategy for any buried archaeological deposits is avoidance. A specific mitigation plan shall be prepared for any unavoidable impacts to any CRHR-eligible (as determined by the CPM) resources. A prescriptive treatment plan may be included in the CRMMP for limited data types.

3. Specification of the implementation sequence and the estimated time frames needed to accomplish all project-related tasks during the ground-disturbance and post-ground–disturbance analysis phases of the project.

4. Identification of the person(s) expected to perform each of the tasks, their responsibilities, and the reporting relationships between project construction management and the mitigation and monitoring team.

5. A description of the manner in which Native American observers or monitors will be included, the procedures to be used to select them, and their role and responsibilities.

6. A description of all impact-avoidance measures (such as flagging or fencing) to prohibit or otherwise restrict access to sensitive resource areas that are to be avoided during ground disturbance, construction, and/or operation, and identification of areas where these measures are to be implemented. The description shall address how these measures would be implemented prior to the start of ground disturbance and how long they would be needed to protect the resources from project-related effects.

7. A statement that all encountered cultural resources over 50 years old shall be recorded on DPR 523 forms and mapped and photographed. In addition, all archaeological materials retained as a result of the archaeological investigations (survey, testing, data recovery) shall be curated in accordance with the California State Historical Resources Commission's (SHRC) Guidelines for the Curation of Archaeological Collections (SHRC 1993), into a retrievable storage collection in a public repository or museum.

8. A statement that the project owner will pay all curation fees for artifacts recovered and for related documentation produced during cultural resources investigations conducted for the project. The project owner shall identify three possible curation facilities that could accept cultural resources materials resulting from project activities.

9. A statement demonstrating when and how the project owner will comply with Health and Human Safety Code, section 7050.5(b) and Public Resources Code, section 5097.98(b) and (e), including the statement that the project owner will notify the CPM and the NAHC of the discovery of human remains.

10. A statement that the CRS has access to equipment and supplies necessary for site mapping, photography, and recovery of any cultural resource materials that are encountered during ground disturbance and cannot be treated prescriptively.

11. **A description of the contents, format, and review and approval process of the final cultural resources report (CRR), which shall be prepared according to Archaeological Resource Management Report (ARMR) guidelines.**

Verification:

~~1. A description of the contents, format, and review and approval process of the final cultural resources report (CRR), which shall be prepared according to Archaeological Resource Management Report (ARMR) guidelines.~~

1. Upon approval of the CRS proposed by the project owner, the CPM will provide to the project owner an electronic copy of the draft model CRMMP for the CRS.

2. At least 30 days prior to the start of Cultural Resources Ground Disturbances, the project owner shall submit the CRMMP to the CPM for review and approval.

3. At least 30 days prior to the start of Cultural Resources Ground Disturbances, in a letter to the CPM, the project owner shall agree to pay curation fees for any materials generated or collected as a result of the archaeological investigations (survey, testing, and data recovery).

4. Within 90 days after completion of Cultural Resources Ground Disturbances (including landscaping), if cultural materials requiring curation were generated or collected, the project owner shall provide to the CPM a copy of an agreement with, or other written commitment from, a curation facility that meets the standards stated in SHRC (1993), to accept the cultural materials from this project. Any agreements concerning curation will be retained and available for audit for the life of the project.

CUL-4 FINAL CULTURAL RESOURCES REPORT (CRR)

The project owner shall submit the final cultural resources report (CRR) to the CPM for approval. The final CRR shall be written by, or under the direction of, the CRS and shall be provided in the ARMR format. The final CRR shall report on all field activities including dates, times and locations, results, samplings, and analyses. The final CRR shall be a confidential document if it describes or maps the location(s) of cultural resources. All survey reports, DPR 523 forms, data recovery reports, and any additional research reports not previously submitted to the California Historical Resources Information System (CHRIS) shall be included as appendices to the final CRR.

If the project owner requests a suspension of ground disturbance and/or construction activities, then a draft CRR that covers all cultural resources activities associated with the project shall be prepared by the CRS and submitted to the CPM for review and approval. The draft CRR shall be retained at the project site in a secure facility until ground disturbance and/or construction resumes or the project is withdrawn. If the project is withdrawn, then a final CRR shall be submitted to the CPM for review and approval.

Verification:

1. Within 30 days after requesting a suspension of construction activities, the project owner shall submit a draft CRR to the CPM for review and approval.

2. Within 90 days after completion of ground disturbance (including landscaping), the project owner shall submit the final CRR to the CPM for review and approval. If any reports have previously been sent to the CHRIS, then receipt letters from the CHRIS or other verification of receipt shall be included in an appendix.

3. Within 10 days after CPM approval of the CRR, the project owner shall provide documentation to the CPM confirming that copies of the final CRR have been provided to the State Historic Preservation Officer, the CHRIS, the curating institution, if archaeological materials were collected, and to the tribal chairpersons of any Native American groups requesting copies of project-related reports.

CUL-5 CULTURAL RESOURCES WORKER ENVIRONMENTAL AWARENESS PROGRAM (WEAP)

Prior to and for the duration of Cultural Resources Ground Disturbances, the project owner shall provide Worker Environmental Awareness Program (WEAP) training to all new workers within their first week of employment at the project site, along the linear facilities routes, and at laydown areas, roads, and other ancillary areas. The cultural resources part of this training shall be prepared by the CRS, may be conducted by any member of the archaeological team, and may be presented in the form of a video. The CRS is encouraged to include a Native American presenter in the training to contribute the Native American perspective on archaeological and ethnographic resources. During the training and during construction, the CRS shall be available (by telephone or in person) to answer questions posed by employees. The training may be discontinued when ground disturbance is completed or suspended, but must be resumed when ground disturbance, such as landscaping, resumes.

Verification: The training shall include:

1. A discussion of applicable laws and penalties under law;
2. Samples or visuals of artifacts that might be found in the project vicinity;
3. A discussion of what such artifacts may look like when partially buried, or wholly buried and then freshly exposed;
4. A discussion of what prehistoric and historical archaeological deposits look like at the surface and when exposed during construction, and the range of variation in the appearance of such deposits;
5. Instruction that the CRS, alternate CRS, and CRMs have the authority to halt ground disturbance in the area of a discovery to an extent sufficient to ensure that the resource is protected from further impacts, as determined by the CRS;
6. Instruction that employees, if the CRS, alternate CRS, or CRMs are not present, are to halt work on their own in the vicinity of a potential cultural resources discovery, and shall contact their supervisor and the CRS or CRM, and that redirection of work would be determined by the construction supervisor and the CRS;
7. An informational brochure that identifies reporting procedures in the event of a discovery;
8. An acknowledgement form signed by each worker indicating that they have received the training; and
9. A sticker that shall be placed on hard hats indicating that environmental training has been completed.
10. No ground disturbance shall occur prior to implementation of the WEAP program, unless such activities are specifically approved by the CPM.

11. At least 30 days prior to the beginning of ground disturbance, the CRS shall provide the cultural resources WEAP training program draft text and/or training video, including Native American participation, and graphics and the informational brochure to the CPM for review and approval.

12. At least 15 days prior to the beginning of ground disturbance, the CPM will provide to the project owner a WEAP Training Acknowledgement form for each WEAP-trained worker to sign.

13. Monthly, until ground disturbance is completed, the project owner shall provide in the Monthly Compliance Report (MCR) the WEAP Training Acknowledgement forms of workers who have completed the training in the prior month and a running total of all persons who have completed training to date.

CUL-6 UNDISCOVERED CULTURAL RESOURCES

In the event that a CRHR eligible (as determined by the CPM) cultural resource is discovered, at the direction of the CPM, the project owner shall ensure that the CRS or alternate CRS monitors full time all ground disturbances in the area where the CRHR-eligible cultural resources discovery has been made. The level, duration, and spatial extent of monitoring shall be determined by the CPM. In the event that the CRS believes that a current level of monitoring is not appropriate, a letter or email detailing the justification for changing the level of monitoring shall be provided to the CPM for review and approval prior to any change in the level of monitoring.

Full-time archaeological monitoring for the project, if deemed necessary due to the discovery of a CRHR-eligible cultural resource, shall consist of archaeological monitoring of all earth-moving activities in the area(s) of discovery(ies), for as long as the CPM requires.

The project owner shall obtain the services of one or more NAMs to monitor construction-related ground disturbance in areas, if any, where Native American artifacts have been discovered. Contact lists of interested Native Americans and guidelines for monitoring shall be obtained from the NAHC. Preference in selecting a NAM shall be given to Native Americans with traditional ties to the area that shall be monitored. If efforts to obtain the services of a qualified NAM are unsuccessful, the project owner shall immediately inform the CPM. The CPM will either identify potential monitors or will allow construction-related ground disturbance to proceed without an NAM.

If monitoring should be needed, as determined by the CPM, due to the discovery of a CRHR-eligible cultural resource, the CRS shall keep a daily log of any monitoring and other cultural resources activities and any instances of non-compliance with the conditions and/or applicable LORS on forms provided by the CPM. Copies of the daily monitoring logs shall be provided by the CRS to the CPM, if requested by the CPM. From these logs, the CRS shall compile a monthly monitoring summary report to be included in the MCR. If there are no monitoring activities, the summary report shall specify why monitoring has been suspended.

The CRS, at his or her discretion, or at the request of the CPM, may informally discuss cultural resource monitoring and mitigation activities with Energy Commission technical staff.

Cultural resources monitoring activities are the responsibility of the CRS. Any interference with monitoring activities, removal of a monitor from duties assigned by the CRS, or direction to a monitor to relocate monitoring activities by anyone other than the CRS shall be considered non-compliance with these conditions.

Upon becoming aware of any incidents of non-compliance with the conditions and/or applicable LORS, the CRS and/or the project owner shall notify the CPM by telephone or e-mail within 24 hours. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the conditions. When the issue is resolved, the CRS shall write a report describing the issue, the resolution of the issue, and the effectiveness of the resolution measures. This report shall be provided in the next MCR for the review of the CPM.

The research design in the CRMMP shall govern the collection, treatment, retention/disposal, and curation of any archaeological materials encountered. The daily monitoring logs shall at a minimum include the following:

- First and last name of the CRM and any accompanying NAM.
- Time in and out.
- Weather. Specify if weather conditions led to work stoppages.
- Work location (project component). Provide specifics—.e.g., power block, landscaping.
- Proximity to site location. Specify if work conducted within 1000 feet of a known cultural resource.
- Work type (machine).
- Work crew (company, operator, foreman).
- Depth of excavation.
- Description of work.
- Stratigraphy.

- Artifacts, listed with the following identifying features:
- Field artifact #: When recording artifacts in the daily monitoring logs, the CRS shall institute a field numbering system to reduce the likelihood of repeat artifact numbers. A typical numbering system could include a project abbreviation, monitor's initials, and a set of numbers given to that monitor: e.g., HBEP-MB-123.
- Description.
- Measurements.
- Universal Transverse Mercator coordinates.
- Whether artifacts are likely to be isolates or components of larger resources.
- Assessment of significance of any finds.
- Actions taken.
- Plan for the next work day.
- A cover sheet shall be submitted with each day's monitoring logs, and shall at a minimum include the following:
  - Count and list of first and last names of all CRMs and of all NAMs for that day.
  - General description (in paragraph form) of that day's overall monitoring efforts, including monitor names and locations.
  - Any reasons for halting work that day.
  - Count and list of all artifacts found that day: include artifact #, location (i.e., grading in Unit X), measurements, UTMs, and very brief description (i.e., historic can, granitic biface, quartzite flake).
  - Whether any artifacts were found out of context (i.e., in fill, caisson drilling, flood debris, spoils pile).

    If requested by the CPM, copies of the daily monitoring logs and cover sheets shall be provided by email from the CRS to the CPM, as follows:

    - Each day's monitoring logs and cover sheet shall be merged into one PDF document.
    - The PDF title and headings, and emails shall clearly indicate the date of the applicable monitoring logs.
    - PDFs for any revised or resubmitted versions shall use the word "revised" in the title.

Daily and/or weekly maps shall be submitted along with the monitoring logs as follows:

- o The CRS shall provide daily and/or weekly maps of artifacts at the request of the CPM. A map shall also be provided if artifact locations show complexity, high density, or other unique considerations.
- o Maps shall include labeled artifacts, project boundaries, previously recorded sites and isolates, aerial imagery background, and appropriate scales.

The Cultural Resources section of the MCR shall be prepared in coordination with the CRS, and shall include a monthly summary report of cultural resources-related monitoring. The summary shall:

- o List the number of CRMs and NAMs on a daily basis, as well as provide monthly monitoring-day totals.
- o Give an overview of cultural resource monitoring work for that month, and discuss any issues that arose.
- o Describe fulfillment of requirements of each cultural mitigation measure.
- o Summarize the confidential appendix to the MCR, without disclosing any specific confidential details.
- o Include the artifact concordance table (as discussed under the next bullet point), but with removal of UTMs.
- o Contain completed DPR 523A forms for all artifacts recorded or collected in that month shall be submitted as one combined PDF that includes an index and bookmarks. For any artifact without a corresponding DPR form, the CRS shall specify why the DPR form is not applicable or pending (i.e. as part of a larger site update). A concordance table that matches field artifact numbers with the artifact numbers used in the DPR forms shall be included. The sortable table shall contain each artifact’s date of collection and UTM numbers, and note if an artifact has been deaccessioned or otherwise does not have a corresponding DPR form. Any post-field log recordation changes to artifact numbers shall also be noted.
- o If artifacts from a given site location (in close proximity of each other or an existing site) are collected month after month, and if agreed upon with the CPM, a final updated DPR for the site may be submitted at the completion of monitoring. The monthly concordance table shall note that the DPR form for the included artifacts is pending.

Verification:

1. At least 30 days prior to the start of ground disturbance, the CPM will provide to the CRS an electronic copy of a form to be used as a daily monitoring log.

2. While monitoring is on-going and as required by the CPM, the project owner shall submit each day's monitoring logs and cover sheet merged into one PDF document by email within 24 hours.

3. The CRS and/or project owner shall notify the CPM of any incidents of noncompliance with the conditions and/or applicable LORS by telephone or email within 24 hours.

4. If resources are discovered as outlined in this condition of certification, the project owner shall notify all local Native American groups of the discovery of the resource within 48 hours of its discovery. If resources are discovered as outlined in this condition of certification, the project owner shall appoint one or more NAMs. Within 15 days of receiving from a local Native American group a request that a NAM be employed, the project owner shall submit a copy of the request and a copy of a response letter to the CPM. The project owner shall include a copy of this condition of certification in any response letter.

5. While monitoring is on-going, the project owner shall include in each MCR a copy of the monthly summary of cultural resources related monitoring prepared by the CRS and shall attach any new DPR 523A forms completed for finds treated prescriptively, as specified in the CRMMP.

6. Final updated DPRs with sites (where artifacts are collected month after month) can be submitted at the completion of monitoring, as agreed upon with the CPM.

7. At least 24 hours prior to implementing a proposed change in monitoring level, the project owner shall submit to the CPM, for review and approval, a letter or email detailing the CRS's justification for changing the monitoring level.

8. Within 15 days of receiving them, the project owner shall submit to the CPM copies of any comments or information provided by Native Americans in response to the project owner's transmittals of information.

CUL-7 POWERS OF CRS

The CRS shall have the authority to halt ground disturbance in the event of a discovery. Redirection of ground disturbance shall be accomplished under the direction of the construction supervisor in consultation with the CRS.

In the event that a cultural resource over 50 years of age is found (or if younger, determined exceptionally significant by the CRS), or impacts to such a resource can be anticipated, ground disturbance shall be halted or redirected in the immediate vicinity of the discovery sufficient to ensure that the resource is protected from further impacts. If the discovery includes human remains, the project owner shall comply with the requirements of Health and Human Safety Code, section 7050.5(b) and notify the CPM and the NAHC of the discovery of human remains. No action with respect to the disposition of human remains of Native American origin shall be initiated without direction from the CPM. Monitoring, including Native American monitoring, and daily reporting, as provided in other conditions, shall continue during the project's ground-disturbing activities on other areas of the project site, while the halting or redirection of ground disturbance in the vicinity of the discovery shall remain in effect until the CRS has visited the discovery, and all of the following have occurred:

1. The CRS has notified the project owner, and the CPM has been notified within 24 hours of the discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday, and provided a description of the discovery (or changes in character or attributes), the action taken (i.e., work stoppage or redirection), a recommendation of CRHR/NRHP eligibility, and recommendations for data recovery from any cultural resources discoveries, whether or not a determination of CRHR/NRHP eligibility has been made.

2. If the discovery would be of interest to Native Americans, the CRS has notified all Native American groups that expressed a desire to be notified in the event of such a discovery.

3. The CRS has completed field notes, measurements, and photography for a DPR 523 "Primary Record" form. Unless the find can be treated prescriptively, as specified in the CRMMP, the "Description" entry of the DPR 523 "Primary Record" form shall include a recommendation on the CRHR/NRHP eligibility of the discovery. The project owner shall submit completed forms to the CPM.

4. The CRS, the project owner, and the CPM have conferred, and the CPM has concurred with the recommended eligibility of the discovery and approved the CRS's proposed data recovery, if any, including the curation of the artifacts, or other appropriate mitigation; and any necessary data recovery and mitigation have been completed.

5. Ground disturbance may resume only with the approval of the CPM.

Verification:

1. At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM and CRS with a letter confirming that the CRS, alternate CRS, and CRMs have the authority to halt ground disturbance in the vicinity of a cultural resources discovery, and that the project owner shall ensure that the CRS notifies the CPM within 24 hours of a discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday.

2. Unless the discovery can be treated prescriptively, as specified in the CRMMP, completed DPR 523 forms for resources newly discovered during ground disturbance shall be submitted to the CPM for review and approval no later than 24 hours following the notification of the CPM, or 48 hours following the completion of data recordation/recovery, whichever the CRS decides is more appropriate for the subject cultural resource.

3. Within 48 hours of the discovery of a resource of interest to Native Americans, the project owner shall ensure that the CRS notifies all Native American groups that expressed a desire to be notified in the event of such a discovery, and the CRS must inform the CPM when the notifications are complete.

4. No later than 30 days following the discovery of any Native American cultural materials, the project owner shall submit to the CPM copies of the information transmittal letters sent to the chairpersons of the Native American tribes or groups who requested the information. Additionally, the project owner shall submit to the CPM copies of letters of transmittal for all subsequent responses to Native American requests for notification, consultation, and reports and records.

5. Within 15 days of receiving them, the project owner shall submit to the CPM copies of any comments or information provided by Native Americans in response to the project owner's transmittals of information.

CUL-8 FILL SOILS

If fill soils must be acquired from a non-commercial borrow site or disposed of to a non-commercial disposal site, the CRS shall survey the borrow or disposal site(s) for cultural resources and record on DPR 523 forms any that are identified. This survey shall not be required if there is a survey of the location that is less than five years old and if the site is approved by the CPM.

When any non–commercial borrow site or non-commercial disposal site survey is completed, the CRS shall convey the results and recommendations for further action to the project owner and the CPM. The CPM shall determine, in his/her sole discretion, whether significant archaeological resources that cannot be avoided are present at the borrow or disposal site. If the CPM determines that significant archaeological resources that cannot be avoided are present at the borrow or disposal site, the project owner must either select another borrow or disposal site or implement **CUL-7** prior to any use of the site. The CRS shall report on the methods and results of these surveys in the final CRR.

Verification:

1. As soon as the project owner knows that a non-commercial borrow site and/or disposal site will be used, he/she shall notify the CRS and CPM and provide documentation of previous archaeological survey, if any, dating within the past five years, for CPM approval.

2. In the absence of documentation of recent archaeological survey, at least 30 days prior to any soil borrow or disposal activities on the non-commercial borrow and/or disposal sites, the CRS shall survey the site(s) for archaeological resources. The CRS shall notify the project owner and the CPM of the results of the cultural resources survey, with recommendations, if any, for further action.

CULTURAL RESOURCES ABBREVIATION AND ACRONYM GLOSSARY

AB	Assembly Bill
AES	AES Southland Development (project owner)
Cal. Code Regs., tit. 20	Title 20, California Code of Regulations
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CHRIS	California Historical Resources Information System
Conditions	Conditions of Certifications
CRHR	California Register of Historical Resources
EMS	Environmental Management Strategies
HBEP	Huntington Beach Energy Project
HBGS	Huntington Beach Generating Station
HCRE	Historic and Cultural Resources Element
LORS	laws, ordinances, regulations, and standards
MBC	MBC Applied Environmental Sciences
NAHC	Native American Heritage Commission
PAA	project area of analysis
PTA	petition to amend
Pub. Resources Code	Public Resources Code (State of California)
SCCIC	South Central Coastal Information Center

REFERENCES

The *tn: 00000* in a reference below indicates the transaction number under which the item is catalogued in the Energy Commission's Docket Unit. The transaction number allows for quicker location and retrieval of individual items docketed for a case or used for ease of reference and retrieval of exhibits cited in briefs and used at Evidentiary Hearings.

HBEP 2012a - AES Southland Development, LLC / Stephen O'Kane (TN 66003). Application for Certification (AFC), Volume I & II, dated, 06/27/2012. Submitted to CEC/Dockets on 06/27/2012.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HBEP 2015h - Data Responses, Set1 (Responses to Data Request 1-74) (TN 206858). Submitted to CEC/Docket Unit on December 7, 2015.

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

CEC 2014d - Final Staff Assessment (TN 202405). Submitted to CEC/ Docket Unit June 2, 2014.

HBEP 2012a - Environmental Management Strategies. *Phase I Environmental Site Assessment: Huntington Beach Electrical Power Plant, 21730 Newland Street, Huntington Beach, CA*. February. Irvine, CA. Prepared for AES North American Development, Long Beach, CA. Appendix 5.14A in *Application for Certification: Huntington Beach Energy Project*, by AES. June. Vol. 2. Submitted to California Energy Commission, Sacramento. TN #66003.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). Melissa Fowler. Huntington Beach Energy Project: Biological Reconnaissance Survey for Plains All American Tank Farm. September 2. CH2M Hill. Prepared for AES Southland Development. Appendix 5.2A to *Petition to Amend Huntington Beach Energy Center (12-AFC-02C)*, by AES Southland Development, with CH2M Hill. September. Long Beach, CA. CEC/Docket Unit on September 9, 2015.

Galvin 2014a - Galvin Preservation Associates. *City of Huntington Beach Historic Resources Context and Survey Report*. Updated 2014. Prepared for City of Huntington Beach, CA.

Galvin 2014b - Galvin Preservation Associates. *City of Huntington Beach Historic Resources Context and Survey Report*. Prepared for the City of Huntington Beach. Updated 2014.

Hoover 2000 - Anna M. Hoover**.** *Cultural Resources Literature and Records Review for the Southeast Coastal Industrial Area Redevelopment Project, Huntington Beach, California*. November. RMW Paleo Associates, Mission Viejo, CA. Project No. 00-1767. Submitted to William Frost & Associates, Irvine, CA. On file, South Central Coastal Information Center, California Historical Resources Information System, Fullerton. Study OR-02456.

MBC 2010 - MBC Applied Environmental Sciences. *Site Assessment of the Plains All American Pipeline Property, Huntington Beach, Orange County, California*. May. Costa Mesa, CA. Prepared for Plains All American Pipeline, Long Beach, CA, and WGR Southwest, Los Alamitos, CA. Attachment A to *Draft Mitigated Negative Declaration, Magnolia Oil Storage Tanks Demolition and Transfer Piping Removal*, by Hayden Beckman. November 29. Planning & Building Department, City of Huntington Beach, CA. MND No. 2010-007. Electronic document, http://www.huntingtonbeachca.gov/government/departments/planning/environmental-reports/files/Attachment-5.3--Magnolia-Oil.pdf, accessed February 12, 2016.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-2C)
Petition to Amend Final Commission Decision
HAZARDOUS MATERIALS MANAGEMENT
Brett Fooks, PE and Geoff Lesh, PE

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Huntington Beach Energy Project (HBEP) proposes to modify the project and would not require substantive changes to the existing set of hazardous materials management conditions of certification. Consistent with the conclusions in the project's licensed Huntington Beach Energy Project 2014 Energy Commission Final Decision (Decision), staff has determined that 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 2014 Decision is necessary for Hazardous Materials Management. The committee may rely upon the environmental analysis and conclusions of the 2014 Decision with regards to Hazardous Materials Management and does not need to re-analyze them.

Staff determined that by following the existing conditions of certification resulting from the 2014 Decision with minor edits to conditions **HAZ-4**, **HAZ-8**, and **HAZ-9**, hazardous materials storage and use at HBEP 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 PTA would require new mitigation or modified hazard materials management conditions of certification. As discussed in detail in the Project Description section, the amended HBEP would be a natural gas fired, combined-cycle and simple-cycle, air-cooled electrical generating facility on the site of the existing Huntington Beach Generation Station (HBGS) in the city of Huntington Beach, California.

SUMMARY OF THE DECISION

The Decision 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 Committee found that the project would comply will all applicable LORS and would not result in any unmitigated significant impacts.

Hazardous Materials Management Table 1
Laws, Ordinances, Regulations, and Standards

Applicable LORS	Description
Federal	
The Superfund Amendments and Reauthorization Act of 1986 (42 USC §9601 et seq.)	Contains the Emergency Planning and Community Right To Know Act (also known as SARA Title III).
The Clean Air Act (CAA) of 1990 (42 USC 7401 et seq. as amended)	Established a nationwide emergency planning and response program and imposed reporting requirements for businesses that store, handle, or produce significant quantities of extremely hazardous materials.
The CAA section on risk management plans (42 USC §112(r)	Requires states to implement a comprehensive system informing local agencies and the public when a significant quantity of such materials is stored or handled at a facility. The requirements of both SARA Title III and the CAA are reflected in the California Health and Safety Code (CA H&S), section 25531, et seq.
49 CFR 172.800	The U.S. Department of Transportation (DOT) requirement that suppliers of hazardous materials prepare and implement security plans.
49 CFR Part 1572, Subparts A and B	Requires suppliers of hazardous materials to ensure that all their hazardous materials drivers are in compliance with personnel background security checks.
The Clean Water Act (40 CFR 112)	Aims to prevent the discharge or threat of discharge of oil into navigable waters or adjoining shorelines. Requires a written spill prevention, control, and countermeasures plan to be prepared for facilities that store oil that could leak into navigable waters.
Title 49, Code of Federal Regulations, Part 190	Outlines gas pipeline safety program procedures.
Title 49, Code of Federal Regulations, Part 191	Addresses transportation of natural and other gas by pipeline: annual reports, incident reports, and safety-related condition reports. Requires operators of pipeline systems to notify the DOT of any reportable incident by telephone and then submit a written report within 30 days.
Title 49, Code of Federal Regulations, Part 192	Addresses transportation of natural and other gas by pipeline and minimum federal safety standards, specifies minimum safety requirements for pipelines including material selection, design requirements, and corrosion protection. The safety requirements for pipeline construction vary according to the population density and land use that characterize the surrounding land. This part also contains regulations governing pipeline construction (which must be followed for Class 2 and Class 3 pipelines) and the requirements for preparing a pipeline integrity management program.
Federal Register (6 CFR Part 27) interim final rule	A regulation of the U.S. Department of Homeland Security that requires facilities that use or store certain hazardous materials to submit information to the department so that a vulnerability assessment can be conducted to determine what certain specified security measures shall be implemented.
State	
Title 8, California Code of Regulations, section 5189	Requires facility owners to develop and implement effective safety management plans that ensure that large quantities of hazardous materials are handled safely. While such requirements primarily provide for the protection of workers, they also indirectly improve public safety and are coordinated with the Risk Management Plan (RMP) process.

Applicable LORS	Description
Title 8, California Code of Regulations, section 458 and sections 500 to 515	Sets forth requirements for the design, construction, and operation of vessels and equipment used to store and transfer ammonia. These sections generally codify the requirements of several industry codes, including the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, the American National Standards Institute (ANSI) K61.1 and the National Boiler and Pressure Vessel Inspection Code. These codes apply to anhydrous ammonia but are also used to design storage facilities for aqueous ammonia.
California Health and Safety Code, section 25531 to 25543.4	The California Accidental Release Program (CalARP) requires the preparation of a RMP and off-site consequence analysis and submittal to the local Certified Unified Program Agency for approval.
California Health and Safety Code, section 41700	Requires that “No person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property.”
California Safe Drinking Water and Toxic Enforcement Act (Proposition 65)	Prevents certain chemicals that cause cancer and reproductive toxicity from being discharged into sources of drinking water.
California Public Utilities Commission General Order 112-E and 58-A	Contains standards for gas piping construction and service.
Local (or locally enforced)	
City of Huntington Beach Municipal Code Section 17.58	Develop and implement safety management plans as required by CA H&SC Sections 25500-25520. Administered by the Huntington Beach Fire Department
Huntington Beach Fire Department City Specifications	Various Huntington Beach Fire Department City Specifications (numbered 401 through 434) may be found at: http://www.huntingtonbeachca.gov/government/departments/Fire/fire_prevention_code_enforcement/fire_dept_city_specifications.cfm
City of Huntington Beach Municipal Code, Chapter 17.56	City of Huntington Beach Fire Code: The City of Huntington Beach has adopted the California Fire Code and has adopted several ordinances which amend it.
National Fire Protection Association (NFPA) 56	NFPA 56 is the Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems.

There have not been any changes to the applicable list of LORS since the Commission Decision was adopted, and the project would continue to comply with all applicable laws, ordinances, regulations, and standards.

ENVIRONMENTAL IMPACT ANALYSIS

Staff has reviewed the PTA for potential environmental impacts and for consistency with applicable LORS. Staff has determined that the PTA does not increase or decrease the use, storage, or transportation of hazardous materials.

After reviewing the PTA, staff has proposed revisions to conditions of certification **HAZ-4**, **HAZ-8**, and **HAZ-9**. **HAZ-4** was revised to update the design standard of the aqueous ammonia storage tank to the ASME Code for Unfired Pressure Vessels, Section VIII, Division 1. The condition referenced ANSI K61.6, an old standard applicable for anhydrous ammonia which the project would not be using. The API 620 was removed because the project would not build an aqueous ammonia tank to this standard. **HAZ-8** was updated to reference the latest North American Energy Corporation (NERC) security guidelines, version 1.9, rather than the initial 2002 guidelines. **HAZ-9** was updated to reference the correct citation to the latest version of NFPA 56 for the written procedures.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes 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. The existing conditions of certification resulting from the 2014 Decision (with the changes to **HAZ-4**, **HAZ-8**, and **HAZ-9** 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 <u>**bold underlined**</u> text and deletions are shown in ~~strikethrough~~.

HAZ-1 The project owner shall not use any hazardous materials not listed in Appendix B, below, or in greater quantities or strengths than those identified by chemical name in Appendix B, below, unless approved in advance by the Compliance Project Manager (CPM).

<u>**Verification:**</u> The project owner shall provide to the CPM, in the Annual Compliance Report, a list of hazardous materials, strengths, and quantities contained at the facility.

HAZ-2 The project owner shall concurrently provide a Business Plan and a Risk Management Plan (RMP) prepared pursuant to the California Accidental Release Program (CalARP) to the Huntington Beach Fire Department and the CPM for review. After receiving comments from the Huntington Beach Fire Department 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 Huntington Beach Fire Department for information and to the CPM for approval.

<u>**Verification:**</u> At least thirty (30) days prior to receiving any hazardous material on the site for commissioning or operations, the project owner shall provide a copy of a final Business Plan to the CPM for approval.

At least thirty (30) days prior to delivery of aqueous ammonia to the site, the project owner shall provide the final RMP to the Certified Unified Program Agency (the Huntington Beach Fire Department) 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 and other liquid hazardous materials by tanker truck. The plan shall include procedures, protective equipment requirements, training, and a checklist. It shall also include a section describing all measures to be implemented to prevent mixing of incompatible hazardous materials including provisions to maintain lockout control by a power plant employee not involved in the delivery or transfer operation. This plan shall be applicable during construction, commissioning, and operation of the power plant.

Verification: At least thirty (30) days prior to the delivery of any liquid hazardous material 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 **the ASME Code for Unfired Pressure Vessels, Section VIII, Division 1** ~~either the ASME Pressure Vessel Code and ANSI K61.6 or to API 620~~. ~~In either case, t~~**T**he storage tank shall be protected by a secondary containment basin capable of holding 125 percent of the storage volume or the storage volume plus the volume associated with 24 hours of rain assuming the 25-year storm. The containment basi**n**~~s~~ shall incorporate a vented cover that allows free flow of any aqueous ammonia release into the containment, yet limits the total vent area to not more than 16 square ft. 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 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.

Verification: At least thirty (30) 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-6 Prior to initial delivery, the project owner shall direct vendors delivering bulk quantities (>800 gallons per delivery) of hazardous material (e.g., aqueous ammonia, lubricating and insulating oils) to the site to use only the route approved by the CPM (I-405 to Beach Boulevard (State Highway 39), south onto Pacific Coast Highway (State Highway 1), and left onto Newland Street, then right into the HBEP site). The project owner shall obtain approval of the CPM if an alternate route is desired.

Verification: At least sixty (60) days prior to initial receipt of bulk quantities (>800 gallons per delivery) of hazardous materials (e.g., aqueous ammonia, lubricating or insulating oils) and at least ten (10) days prior to a new vendor delivery of bulk quantities (>800 gallons per delivery), the project owner shall submit a copy of the letter containing the route restriction directions that were provided to the hazardous materials vendor to the CPM for review and approval.

HAZ-7 Prior to commencing construction, a site-specific Construction Site Security Plan for the construction phase shall be prepared and made available to the CPM for review and approval. The Construction **Site** Security Plan shall include the following:

1. perimeter security consisting of fencing enclosing the construction area;
2. security guards;
3. site access control consisting of a check-in procedure or tag system for construction personnel and visitors;
4. written standard procedures for employees, contractors and vendors when encountering suspicious objects or packages on site or off site;
5. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency; and,
6. evacuation procedures.

Verification: At least thirty (30) days prior to commencing construction, the project owner shall notify the CPM that a site-specific Construction Security Plan is available for review and approval.

HAZ-8 The project owner shall also prepare a site-specific security plan for the commissioning and operational phases that will be available to the CPM for review and approval. The project owner shall implement site security measures that address physical site security and hazardous materials storage. The level of security to be implemented shall not be less than that described below (as per NERC **Security Guideline for the Electricity Sector: Physical Security v1.9** ~~2002~~).

The Operation Security Plan shall include the following:

1. Permanent full perimeter fence or wall, at least eight feet high and topped with barbed wire or the equivalent (and with slats or other methods to restrict visibility if a fence is selected;
2. Main entrance security gate, either hand operated or motorized;
3. Evacuation procedures;
4. Protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency;

5. Written standard procedures for employees, contractors, and vendors when encountering suspicious objects or packages on site or off site;

    A. A statement (refer to sample, **Attachment A**), signed by the project owner certifying that background investigations have been conducted on all project personnel. Background investigations shall be restricted to determine the accuracy of employee identity and employment history and shall be conducted in accordance with state and federal laws regarding security and privacy;

    B. A statement(s) (refer to sample, **Attachment B**), signed by the contractor or authorized representative(s) for any permanent contractors or other technical contractors (as determined by the CPM after consultation with the project owner), that are present at any time on the site to repair, maintain, investigate, or conduct any other technical duties involving critical components (as determined by the CPM after consultation with the project owner) certifying that background investigations have been conducted on contractors who visit the project site;

6. Site access controls for employees, contractors, vendors, and visitors;

7. A statement(s) (refer to sample, **Attachment C**), signed by the owners or authorized representative of hazardous materials transport vendors, certifying that they have prepared and implemented security plans in compliance with 49 CFR 172.880, and that they have conducted employee background investigations in accordance with 49 CFR Part 1572, subparts A and B;

8. Closed circuit TV (CCTV) monitoring system, recordable, and viewable in the power plant control room and security station (if separate from the control room) with cameras able to pan, tilt, and zoom, have low-light capability, and are able to view 100% of the perimeter fence, the ammonia storage tank, the outside entrance to the control room, and the front gate; and,

9. Additional measures to ensure adequate perimeter security consisting of either:

    A. Security guard(s) present 24 hours per day, 7 days per week; or

    B. Power plant personnel on site 24 hours per day, 7 days per week, and perimeter breach detectors or on-site motion detectors.

The project owner shall fully implement the security plans and obtain CPM approval of any substantive modifications to those security plans. The CPM may authorize modifications to these measures, or may require additional measures such as protective barriers for critical power plant components - transformers, gas lines, and compressors - depending upon circumstances unique to the facility or in response to industry-related standards, security concerns, or additional guidance provided by the U.S. Department of Homeland Security, the U.S. Department of Energy, or the North American Electrical Reliability Council, after consultation with both appropriate law enforcement agencies and the applicant.

Verification: At least thirty (30) days prior to the initial receipt of hazardous materials on site, the project owner shall notify the CPM that a site-specific operations site security plan is available for review and approval. In the annual compliance report, the project owner shall include a statement that all current project employee and appropriate contractor background investigations have been performed, and that updated certification statements have been appended to the operations security plan. In the annual compliance report, the project owner shall include a statement that the operations security plan includes all current hazardous materials transport vendor certifications for security plans and employee background investigations.

HAZ-9: The project owner shall not allow any fuel gas pipe cleaning activities on site, either before placing the pipe into service or at any time during the lifetime of the facility, that involve “flammable gas blows” where natural (or flammable) gas is used to blow out debris from piping and then vented to atmosphere. Instead, an inherently safer method involving a non-flammable gas (e.g. air, nitrogen, steam) or mechanical pigging shall be used as per NFPA 56. A written procedure shall be developed and implemented as per NFPA 56, section **4.4.1.** ~~4.3.1~~

Verification: At least 30 days before any fuel gas pipe cleaning activities begin, the project owner shall submit a copy of the Fuel Gas Pipe Cleaning Work Plan (as described in NFPA 56, section **4.4.1** ~~4.3.1~~) which shall indicate the method of cleaning to be used, what gas will be used, the source of pressurization, and whether a mechanical PIG will be used, to the CBO for information and to the CPM for review and approval.

REFERENCES

HBEP 2012a - AES Southland Development, LLC / Stephen O'Kane (TN 66003). Application for Certification (AFC), Volume I & II, dated, 06/27/2012. Submitted to CEC/Dockets on 06/27/2012.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

SAMPLE CERTIFICATION (Attachment A)

Affidavit of Compliance for Project Owners

I,

____

(Name of person signing affidavit)(Title)

do hereby certify that background investigations to ascertain the accuracy of the identity and employment history of all employees of

____

(Company name)

for employment at

____

(Project name and location)

have been conducted as required by the California Energy Commission Decision for the above-named project.

____

(Signature of officer or agent)

Dated this ___________________ day of ___________________, 20 _______.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

SAMPLE CERTIFICATION (Attachment B)

Affidavit of Compliance for Contractors

I,

____

(Name of person signing affidavit)(Title)

do hereby certify that background investigations to ascertain the accuracy of the identity and employment history of all employees of

____

(Company name)

for contract work at

____

(Project name and location)

have been conducted as required by the California Energy Commission Decision for the above-named project.

____

(Signature of officer or agent)

Dated this ____________________ day of ____________________, 20 _______.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

SAMPLE CERTIFICATION (Attachment C)

Affidavit of Compliance for Hazardous Materials Transport Vendors

I,

____

(Name of person signing affidavit)(Title)

do hereby certify that the below-named company has prepared and implemented security plans in conformity with 49 CFR 172.880 and has conducted employee background investigations in conformity with 49 CFR 172, subparts A and B,

____

(Company name)

for hazardous materials delivery to

____

(Project name and location)

as required by the California Energy Commission Decision for the above-named project.

____

(Signature of officer or agent)

Dated this ____________________ day of ____________________, 20 _______.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
LAND USE
Steven Kerr

SUMMARY OF CONCLUSIONS

California Energy Commission (Energy Commission) staff concludes that the proposed amendment to the license for the Huntington Beach Energy Project (HBEP) would have no new land use impacts and the mitigation for the original project would still be applicable. This mitigation would not require any substantive changes beyond the minor update to condition of certification **LAND-1** to include the additional 1.4 acres that the project owner has acquired from Southern California Edison (SCE), increasing the size of the Huntington Beach Energy Project (HBEP) site from 28.6 acres as licensed to 30 acres as amended. Staff also concludes that the findings of fact from the November 2014 Commission Decision (Decision) would still apply to the amended HBEP. Therefore, in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162, staff concludes that no supplementation to the Decision is necessary for Land Use. The Committee may rely upon the environmental analysis and conclusions of the Decision with regards to land use and does not need to re-analyze them.

INTRODUCTION

Staff reviewed the Decision for the licensed HBEP and analyzed the proposed changes for the amended HBEP. As discussed in detail in the Project Description section of this document, the amended HBEP would be a natural-gas-fired, combined-cycle and simple-cycle, air-cooled electrical generating facility located on the site of the existing Huntington Beach Generation Station (HBGS) in Huntington Beach, California.

SUMMARY OF THE DECISION

The list below provides a short summary of the Decision with regards to the Land Use technical area. Based on the evidence presented in the original proceeding, the Energy Commission made the following findings and conclusions.

FINDINGS OF FACT

1. The HBEP is not subject to a Williamson Act contract.

2. The project will not result in conversion of farmland to non-agricultural uses.

3. The HBEP, a repurposing of an existing industrial use, will not physically divide or disrupt an established community.

4. The project will not conflict with a habitat or conservation plan.

5. The project will be built on private lands.

6. The project will not contribute to a significant cumulative impact to land use inconsistencies within the area surrounding the project site.

7. The construction site has a Huntington Beach General Plan designation of Public.

8. The project site in the city of Huntington Beach has a zoning designation of Public-Semipublic and is within the Coastal Zone Overlay District.

9. The project would require a variance, a conditional use permit, and a coastal development permit but for the exclusive licensing jurisdiction of the Energy Commission.

10. The findings in support of a variance under the Huntington Beach Municipal Code can be made.

11. The findings in support of a conditional use permit under the Huntington Beach Municipal Code can be made.

12. The findings to support the granting of a coastal development permit under the Huntington Beach Municipal Code can be made.

13. The construction laydown yard in the city of Long Beach has a General Plan designation of Mixed Use.

14. The construction laydown yard in the city of Long Beach is within the South East Area Development and Improvement Plan.

15. The HBEP is compatible with surrounding land uses and will not result in any unmitigated public health or other environmental impacts to sensitive receptors.

CONCLUSIONS OF LAW

1. The record contains an adequate analysis of the land use laws, ordinances, regulations, and standards that are relevant to the project and establishes that the project will not create any unmitigated, significantly adverse land use effects as defined under the CEQA.

2. With the making of the necessary findings for a variance, conditional use permit, and coastal development permit, the HBEP is consistent with the land use policies, plans, and regulations of the city of Huntington Beach.

3. The construction laydown yard in the city of Long Beach is consistent with the land use policies, plans, and regulations of the city of Long Beach.

4. The HBEP complies with the provisions in Chapter 3 of the Coastal Act. (CEC 2014bb, pg. 6.1-24 – 6.1-25)

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

No LORS applicable to the project have changed since the Commission Decision was published in November 2014. Additionally, the proposed amendment would not trigger new LORS that may not have been applicable to the original project.

ENVIRONMENTAL IMPACT ANALYSIS

In accordance with CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Decision is necessary for Land Use. The Committee may rely upon the environmental analysis and conclusions of the Decision with regards to land use and does not need to re-analyze them due to the following conclusions.

- 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 Land Use analysis in the Decision.
- The circumstances under which the amended HBEP would be undertaken would not require major revisions of the Land Use analysis in the Decision.

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

- No LORS applicable to land use have changed since the Decision was published in November 2014.
- The city of Huntington Beach General Plan designation of Public (P) and zoning of Public-Semi-public (PS) and Coastal Zone Overlay District (CZ), as well as the Oil Production Overlay District (O) remain the same for the project site.
- Major utilities are permitted uses in the PS zone and CZ overlay district subject to a conditional use permit and coastal development permit.
- The findings from the Decision in support of a variance, conditional use permit, and coastal development permit for the licensed HBEP are applicable to the amended HBEP.
- With implementation of existing condition of certification **LAND-1** the amended HBEP would be consistent with the city of Huntington Beach existing land use plans and zoning ordinances.
- Existing condition of certification **LAND-1** would remain applicable and feasible and the project proponent, AES Southland Development, LLC, has not requested any changes to the condition.

The amended HBEP would be constructed entirely within the site of the existing HBGS. Both power blocks would interconnect to the existing onsite SCE 230-kilovolt switchyard (HBEP 2015a, 5.6-1).

Staff proposes one minor update to **LAND-1** to include the additional 1.4 acre triangle-shaped paved parking lot between the SCE substation and the boundary of the licensed HBEP that the project owner acquired from SCE, which would increase the HBEP site from 28.6 acres as licensed to 30 acres as amended (HBEP 2015a, 5.6-1).

Construction of the amended HBEP may utilize an additional 20 acres beyond the 1.9 acres identified in the Commission Decision at the former Plains All American Tank Farm site located adjacent to the HBEP site for temporary offsite construction laydown and construction worker parking. As previously identified in the Decision, the General Plan land use designation for the Plains All American Tank Farm site is Pubic and the zoning is Public-Semi-public (CEC 2014bb, p. 6.1-6). Further utilization of the Plains All American Tank Farm site would be preferable to the other previously identified potential offsite laydown and parking areas because of its close proximity to the project site (HBEP 2015a, p. CEC 2014d, p. 4.5-5). For additional information regarding temporary offsite construction laydown and construction worker parking, please see the **TRAFFIC AND TRANSPORTATION** and **BIOLOGICAL RESOURCES** sections of this assessment.

But for the Energy Commission’s exclusive authority to license the project, licensing the HBEP within the HBGS site would have required the following land use actions by the city of Huntington Beach:

- A Variance to exceed the maximum allowable structure height within the PS zone.
- A Conditional Use Permit to allow development of a Major Utility use within the PS zone.
- A Coastal Development Permit to allow development within the CZ overlay district. (CHB 2016a, section 241.10)

VARIANCE

Under the zoning and subdivision ordinance in the city of Huntington Beach, structures in the PS district are limited to 50 feet. The licensed HBEP would have utilized stacks of approximately 120 feet in height in order to meet air quality permitting standards of the South Coast Air Quality Management District. In order for the HBEP to locate in the area, it would thus need a variance.

The Huntington Beach City Council adopted its Resolution No. 2014-18 on April 7, 2014. While recognizing the exclusive permitting jurisdiction of the Energy Commission, the City Council nonetheless stated that if it had jurisdiction over the HBEP, it would grant the necessary variance.

In the Decision the Energy Commission gave due deference to the determination by the city of Huntington Beach of its own ordinances. (Cal. Code Regs., tit. 14, §1744(e).) The Energy Commission found that the evidence contained in the city's resolution was sufficient to support the necessary findings for a variance related to the over-height of the structures proposed by the licensed HBEP. The City Council cited to the long history of the power plant being on the site of the HBEP, as well as the significant reduction in height from the current HBGS. These factors allowed the city to conclude that denying a variance would result in a loss of a substantial property right, especially when coupled with the general plan and zoning designations on the site authorizing the continued existence of a power plant.

The amended HBEP proposes stack heights of 150 feet for the GE Frame 7FA.05 combustion-turbine generator units and 80 feet in height for the LMS100 units. While the 150-foot stack height for the amended project is higher than the 120-foot stack height of the licensed project, it is still a significant reduction in height from the current HBGS stack heights of 200 feet. Therefore, staff concludes that the Energy Commission's findings related to the variance for the licensed HBEP would still be relevant to the amended HBEP and would not require major revisions to the previous decision.

The approval of the variance for the licensed HBEP relied on the submission of architectural and landscaping plans for screening (CEC 2014bb, p. 6.1-19). On March 10, 2016, the city of Huntington Beach Design Review Board reviewed the project owner's revised conceptual architectural screening plan for the amended HBEP and forwarded a recommendation for approval to the City Council (HBEP 2016). The City Council is expected to adopt a new resolution addressing the revised architectural screening plan and updating their findings for the variance, conditional use permit, and coastal development permit prior to the publication of staff's Final Staff Assessment (FSA). Accordingly, staff will incorporate any updated findings from the city into the FSA when they become available. An assessment of applicable city policies regarding screening and design improvements and the required architectural improvement plan is included in the **VISUAL RESOURCES** section of this assessment. Condition of certification **VIS-1** includes the requirements for the architectural and landscaping plans for screening.

CONDITIONAL USE PERMIT

The Energy Commission found that a conditional use permit could be issued for the licensed HBEP. There would not be detrimental effects from the continued use of the project site for power generation as it would use existing transmission and other linear facilities. The general plan designation and zoning code already authorize use of the site for electrical generation (CEC 2014bb, p. 6.1-19).

Staff finds that the Energy Commission's conditional use permit findings for the licensed HBEP would be applicable to the amended HBEP and would not require major revisions to the previous decision because existing transmission and other linear facilities will still be used and LORS have not changed.

COASTAL DEVELOPMENT PERMIT

The Energy Commission also found that a coastal development permit could be issued for the licensed HBEP. As described above, the HBEP would be built on lands designated in the Huntington Beach General Plan as Public (P). The Coastal Element identifies the existing land use of the site as a regionally serving electrical generating plant, in which Coastal Element policy provides for the use to continue. The base zoning is PS; the site is within the CZ Overlay district. The HBEP would reuse existing onsite potable water, natural gas, storm water, process wastewater and sanitary pipelines, and electrical transmission facilities. Finally, the HBEP meets the requirements of public access and public recreation policies contained in the California Coastal Act. (CEC 2014bb, p. 6.1-20)

Staff finds that the amended HBEP could properly receive a coastal development permit as the circumstances considered for the Energy Commission's findings for the licensed HBEP remain unchanged for the amended project.

Because the amended project would qualify for the issuance of a variance, a conditional use permit, and a coastal development permit, staff finds that the amended HBEP remains consistent with the Huntington Beach zoning code and concludes that no supplementation to the Commission Decision is necessary for Land Use.

The proposed amendment would have no new land use impacts and would not result in a change or deletion of the condition of certification **LAND-1** adopted in the Commission Decision in the licensed HBEP proceeding. Staff recommends a minor edit to condition of certification **LAND-1,** as shown below, to incorporate the additional 1.4 acres that the project owner has acquired from SCE, increasing the size of the HBEP site from 28.6 acres as licensed to 30 acres as amended.

CUMULATIVE IMPACTS

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (Cal. Code Regs., tit. 14, §15065(a)(3).

The cumulative land use and planning analysis considers past, current, and probable future projects that are relatively near the proposed project that would contribute to cumulative impacts by impacting agricultural or forest lands, disrupting or dividing an established community, conflicting with applicable land use plans, policy or regulation, or conflicting with an applicable habitat conservation plan or natural community conservation plan.

Land Use Table 1 (below) displays the reasonably foreseeable significant sized development projects within approximately one mile of the project site in the city of Huntington Beach.

Land Use Table 1
Cumulative Projects

Project Title	Description	Location	Status of Project
Huntington Beach Generating Station Demolition (Demolition of Units 3 & 4)	Demo/removal of Units 3 & 4 from the existing Huntington Beach Generating Station.	Huntington Beach Generating Station, Huntington Beach	Demo estimated Q2 2020 to Q1 2022 (27 mo.)
Poseidon Desalination Plant	A 50 million gallon per day, seawater desalination facility located on 11-acre portion of the existing HBGS facility. Project would use existing HBGS seawater intake and outfall pipelines for operations.	21730 Newland St, Huntington Beach	Planning
Magnolia Oil Storage Tank and Transfer Facility Demolition and Removal	Demolition and removal of three empty above-ground crude oil storage tanks and ancillary site improvements.	21845 Magnolia St, Huntington Beach	In Progress
Newland St Residential (Pacific Shores)	Develop and subdivide former industrial site to residential with 204 multi-family residential units and two-acre public park.	21471 Newland St, Huntington Beach	Completed
Remedial Action Plan for Ascon Landfill Site	Remedial Action Plan (RAP) includes partial removal of waste materials and construction of protective cap over remaining waste materials.	Magnolia St and Hamilton Ave, Huntington Beach	Plan Check
Hilton Waterfront Beach Resort Expansion	Nine-story tower with 156 new guestrooms, appurtenant facilities, 261 parking spaces, a loading dock and other back-of-house facilities.	21100 Pacific Coast Hwy, Huntington Beach	Plan Check
Brookhurst Street Bridge Preventative Maintenance Project	Repair and rehabilitate the Brookhurst Street Bridge in the city of Huntington Beach.	Brookhurst St Bridge, Huntington Beach	Plan Check
P2-92 Sludge Dewatering and Odor Control	Build new sludge and odor control facilities at existing Plant 2.	Santa Ana River Channel, Huntington Beach	Construction scheduled Spring 2016
Pacific City	516 condominiums; 8 story-250 room hotel, spa and health club; and 191,100 sq. ft. visitor-serving commercial with retail, office, restaurant, cultural, and entertainment	21002 Pacific Coast Hwy, Huntington Beach	Under Construction

Source: Executive Summary Table 1

The following land use areas have been analyzed with regard to cumulative land use impacts.

AGRICULTURE AND FOREST

The project as amended does not have any impacts to agricultural or forest lands or conflict with any land that is zoned for agricultural purposes and therefore, does not contribute to cumulative impacts related to this land use area.

PHYSICAL DISRUPTION OR DIVISION OF AN ESTABLISHED COMMUNITY

Because the amended HBEP would be located entirely within the existing HBGS site and would not physically disrupt or divide an established community, it would not contribute to a cumulative impact in this land use area.

CONFLICT WITH ANY APPLICABLE HABITAT OR NATURAL COMMUNITY CONSERVATION PLAN

The amended HBEP does not conflict with any habitat or natural community conservation plans and will not contribute to any cumulative impacts in this land use area.

CONFLICT WITH ANY APPLICABLE LAND USE PLAN, POLICY OR REGULATION

Staff's analysis of the information available shows that the amended project would not conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction, with the inclusion of the proposed condition of certification. The amended HBEP would not result in cumulative impacts in this land use area.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the proposed amendment would have no new land use impacts and the mitigation for the original project would still be applicable and would not require any substantive changes beyond updating the project acreage in condition of certification **LAND-1**. Therefore, staff also concludes that the findings of fact and conclusions of law from the Decision would still apply to the amended HBEP:

FINDINGS OF FACT

1. The HBEP is not subject to a Williamson Act contract.
2. The project will not result in conversion of farmland to non-agricultural uses.
3. The HBEP, a repurposing of an existing industrial use, will not physically divide or disrupt an established community.
4. The project will not conflict with a habitat or conservation plan.
5. The project will be built on private lands.
6. The project will not contribute to a significant cumulative impact to land use inconsistencies within the area surrounding the project site.
7. The construction site has a Huntington Beach General Plan designation of Public.
8. The project site in the city of Huntington Beach has a zoning designation of PS and is within the Coastal Zone Overlay District.

9. The project would require a variance, a conditional use permit, and a coastal development permit but for the exclusive licensing jurisdiction of the Energy Commission.

10. The findings in support of a variance under the Huntington Beach Municipal Code can be made.

11. The findings in support of a conditional use permit under the Huntington Beach Municipal Code can be made.

12. The findings to support the granting of a coastal development permit under the Huntington Beach Municipal Code can be made.

13. The construction laydown yard in the city of Long Beach has a General Plan designation of Mixed Use.

14. The construction laydown yard in the city of Long Beach is within the South East Area Development and Improvement Plan.

15. The HBEP is compatible with surrounding land uses and will not result in any unmitigated public health or other environmental impacts to sensitive receptors.

CONCLUSIONS OF LAW

1. The record contains an adequate analysis of the land use laws, ordinances, regulations, and standards that are relevant to the project and establishes that the project will not create any unmitigated, significantly adverse land use effects as defined under CEQA.

2. With the making of the necessary findings for a variance, conditional use permit, and coastal development permit, the HBEP is consistent with the land use policies, plans, and regulations of the city of Huntington Beach.

3. The construction laydown yard in the city of Long Beach is consistent with the land use policies, plans, and regulations of the city of Long Beach.

4. The HBEP complies with the provisions in Chapter 3 of the Coastal Act.

Socioeconomics Figure 1 does not identify the presence of an environmental justice community. Therefore, the population in the six-mile buffer does not constitute an environmental justice population as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act* and would not trigger further scrutiny for purposes of an environmental justice analysis.

PROPOSED CONDITIONS OF CERTIFICATION

Existing condition of certification **LAND-1** would ensure the project remains in compliance with applicable laws, ordinances, regulations, and standards. Therefore, staff does not propose any modifications to **LAND-1**, with the exception of one minor update to include the additional 1.4 acres that the project owner has acquired from SCE, increasing the size of the HBEP site from 28.6 acres as licensed to 30 acres as amended. (**Note:** Deleted text is in ~~strikethrough~~, new text is **<u>bold and underlined</u>**)

LAND-1 The project owner shall comply with Appendix B(g)(3)(c) of the Siting Regulations (Title 20, California Code of Regulations) by ensuring that the HBEP site, excluding linear and temporary lay down or staging area, will be located on a single legal parcel.

<u>Verification:</u> Prior to construction of the first power block, the project owner shall submit evidence to the compliance project manager (CPM), indicating approval of a Lot Line Adjustment by the city of Huntington Beach, establishing a single parcel for the ~~28.6~~ **<u>30</u>** acre HBEP site. The submittal to the CPM shall include evidence of compliance with all conditions and requirements associated with the approval of the Lot Line Adjustment by the city.

REFERENCES

CEC 2014d - Final Staff Assessment (TN 202405). Submitted to CEC/ Docket Unit June 2, 2014.

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

CHB 2016a - City of Huntington Beach Zoning and Subdivision Ordinance. Accessed February 18, 2016. http://www.huntingtonbeachca.gov/government/Elected_Officials/city_clerk/Zoning_Code/

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HBEP 2016l - Stoel Rives LLP/Melissa A. Foster (TN 210763). Letter to John Heiser Re: Huntington Beach Energy Project - Petition to Amend (12-AFC-02C) Conceptual Design Plan - Status Update, dated March 16, 2016. Submitted to John Heiser/CEC/Docket Unit on March 16, 2016.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
NOISE AND VIBRATION
Edward Brady

SUMMARY OF CONCLUSIONS

Similar to the conclusions in the 2014 Energy Commission Final Decision (Decision) (CEC 2014bb), the potential impacts from the changes to the Huntington Beach Energy Project (HBEP) (HBEP 2015a) as proposed in the petition to amend (PTA) would be less than significant. Therefore, in accordance with the California Environmental Quality Act Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Decision is necessary for Noise and Vibration. The Committee may rely upon the environmental analysis and conclusions of the Decision with regards to Noise and Vibration and does not need to re-analyze them.

Conditions of certification **NOISE-1** through **NOISE-8** contained in the Decision would be sufficient to reduce impacts from the amended project to a less than significant level and to ensure the project would remain in compliance with applicable laws, ordinances, regulations, and standards (LORS) relating to noise and vibration.

INTRODUCTION

Staff has reviewed the Decision (CEC 2014bb) and analyzed the modifications proposed for the HBEP, which include revising the approved pair of three-on-one combined-cycle electric power generating blocks to a single two-on-one combined-cycle power block and two simple-cycle combustion-turbine generators (CTGs). 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 Decision found that the noise impacts associated with the project's construction and operation will be mitigated to the extent feasible, and therefore they will not significantly affect the surrounding communities or the project's construction workers. The Decision concluded that implementation of the staff's proposed Noise and Vibration conditions of certification will ensure that noise and vibration impacts will not cause any significant direct, indirect, or cumulative impacts and that the project will comply with the applicable LORS relating to noise and vibration.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS) COMPLIANCE

No LORS applicable to the project have changed since the Decision was published in 2014. Additionally, the proposed amendment would not trigger new LORS that may not have been applicable to the original project. The applicable Noise and Vibration LORS are listed in **Noise Table 1** below.

Noise Table 1
Laws, Ordinances, Regulations, and Standards

<table>
<tr><th>Applicable LORS</th><th>Description</th></tr>
<tr><td>Federal:
Occupational Safety & Health Act (OSHA): 29 U.S.C. § 651 et seq.

U.S. Environmental Protection Agency (USEPA)</td><td>Protects workers from the effects of occupational noise exposure.

Assists state and local government entities in development of state and local LORS for noise.</td></tr>
<tr><td>State:
California Occupational Safety & Health Act (Cal-OSHA): 29 U.S.C. § 651 et seq., California Code of Regulations, Title 8, §§ 5095-5099</td><td>Protects workers from the effects of occupational noise exposure.</td></tr>
<tr><td>Local:
City of Huntington Beach Municipal Code, Noise Ordinance, Chapter 8.40, Noise Control

City of Huntington Beach General Plan, Noise Element</td><td>Prohibits construction between 8 p.m. and 7 a.m. on Mondays through Saturdays and all day Sundays and federal holidays

Provides the following noise limits for exterior locations.
<table>
<tr><th colspan="3">Exterior Noise Standards</th></tr>
<tr><th>Noise Zone</th><th>Noise Level (dBA)</th><th>Time Period</th></tr>
<tr><td>1 Residential</td><td>55
50</td><td>7 am – 10 pm
10 pm – 7 am</td></tr>
<tr><td>2 Office</td><td>55</td><td>Anytime</td></tr>
<tr><td>3 Commercial</td><td>60</td><td>Anytime</td></tr>
<tr><td>4 Industrial</td><td>70</td><td>Anytime</td></tr>
</table>
Limit at M2 is the existing ambient level, or 62 dBA.

Establishes goals, objectives, and policies that address noise issues within the City's jurisdiction</td></tr>
</table>

Discussions related to LORS compliance are embedded in **ANALYSIS** below.

ANALYSIS

The noise-sensitive receptors previously identified and analyzed in the Decision remain the project's most noise-sensitive receptors and there are no new noise-sensitive receptors in the project area since the issuance of the Decision.

CONSTRUCTION IMPACTS

The amendment describes the amended HBEP's construction and demolition schedule, which is slightly different than the licensed HBEP, but would continue for approximately the same amount of time (8 years) (HBEP 2015a, §§ 5.7.1, 5.7.4). Also, construction and demolition equipment and activities and methods of construction would be similar to those expected for the licensed HBEP.

The licensed HBEP includes 1.9 acres of construction workers' parking on the former Plains All American Tank Farm site located adjacent to the HBEP site. The amended HBEP may require the use of an additional 20 acres on the Plains site, beyond the 1.9 acres identified in the Decision, for construction equipment laydown and construction workers' parking (HBEP 2015a, § 5.7.2). The Plains site is within a few hundred feet from the residential community east of the project site. This community is represented in the Decision by noise monitoring location M3 (CEC 2014bb, p. 6.4-5). The additional traffic on the adjacent street, Magnolia Street, caused by workers activity could potentially impact these residents. However, there is an existing masonry sound wall along Magnolia Street, separating it from this community. This sound wall would provide adequate acoustical protection from the noise due to the increased traffic.

The activities associated with equipment delivery and laydown occurring at this site may have a significant impact, but the existing condition of certification **NOISE-6** would mitigate the impact by limiting construction-related activities to the hours of 7 a.m. to 8 p.m., Monday through Saturday only, in compliance with the LORS (see **Noise Table 1**), and by requiring large trucks to avoid generating excessive and unnecessary noise. Besides, the above sound wall would partially shield the nearby community (represented by M3) from noise associated with equipment laydown. Also, condition of certification **NOISE-2** would establish a noise complaint process to resolve any complaints regarding project-related noise.

Thus, similar to the approved project, the noise impacts of the amended project's construction and demolition activities on the surrounding communities and on the project's construction workers would be less than significant and in compliance with the applicable noise-related LORS.

The Decision concluded that construction equipment and methods of construction would not cause perceptible vibration at any sensitive receptor. Therefore, by using similar construction equipment and methods, this conclusion remains valid for the amended project.

OPERATIONAL IMPACTS

The amended project includes revising the approved project's power blocks. The location of each of the power blocks would remain approximately the same within the project site, but the generating equipment would change. The approved HBEP includes two separate, three-on-one combined-cycle power blocks, consisting of a total of six Mitsubishi M501DA CTGs, six heat recovery steam generators (HRSGs), two steam turbine generators (STGs), and two air-cooled condensers (ACCs), totaling 939 megawatts (MW). The amended HBEP would substitute these power blocks with a single two-on-one combined-cycle power block using two General Electric (GE) 7FA CTGs, two HRSGs, one STG, and one ACC, and a second power block containing two GE LMS100 PB CTGs in a simple-cycle configuration, all totaling 844 MW (HBEP 2015a, §§ 1.0, 2.1). As seen here, the amended project's total MW output would be slightly less than the approved project and the amended project would use fewer pieces of equipment; this would likely result in slightly lower operational noise levels.

In addition, and unlike the licensed project, the amended project would include a tall sound wall along the eastern and southeastern boundaries of the combined-cycle power block (HBEP 2015a, § 5.13.3.2). This would help to reduce offsite noise levels due to the power block's ACC fans, turbines, and other equipment.

Therefore, staff believes that the amended project would be able to comply with the operational noise levels required in condition of certification **NOISE-4** of the Decision (61 dBA at receptor M2, 45 dBA at M3, and 49 dBA at M4) and with the limits set forth in the LORS (**Noise Table 1**, city of Huntington Beach limits). Furthermore, **NOISE-4** prohibits creation of perceptible tonal noise; that is, noise that may not be louder than permissible levels, but stands out in sound quality (for example, from out of tune or old equipment).

Similar to the approved 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** (occupational noise survey and mitigation) contained in the Decision.

Based on experience with several previous projects employing similar power block equipment as those proposed for the amended HBEP, and similar to the licensed HBEP, staff believes that vibration due to the operation of the amended HBEP would be undetectable by any likely receptor.

Staff concludes that project operation would create a less-than-significant noise impact and would remain in compliance with applicable LORS relating to noise and vibration.

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. The staff's updated cumulative project list shows that the only project to potentially create a cumulative noise impact when combined with the amended HBEP remains as the one identified and analyzed in the Decision. This is the Poseidon Seawater Desalination Plant (Poseidon), a water treatment plant to be located adjacent to the HBEP.

The Decision concludes that the cumulative noise impact of the adjacent Poseidon project and the licensed HBEP will be less than significant. Since the amended HBEP would be similar to the licensed HBEP in construction and operational noise levels, the cumulative noise impact of the adjacent Poseidon project and the amended HBEP would be less than significant as well. Therefore, the amended project would not result in any significant cumulative noise impacts.

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.

CONCLUSIONS AND RECOMMENDATIONS

The existing conditions of certification **NOISE-1** through **NOISE-8** would be sufficient to reduce noise and vibration impacts from the proposed amendment to a less than significant level directly, indirectly, and cumulatively and to ensure the project would remain in compliance with applicable LORS relating to noise and vibration.

PROPOSED CONDITIONS OF CERTIFICATION

Staff has deleted redundant footnotes (redundant definitions) and has clarified two of the remaining footnotes in the Noise and Vibration conditions of certification presented below. Deleted text is in ~~strikethrough~~ and new text is **<u>bold and underlined</u>**. Staff does not propose any other modifications to these conditions of certification.

NOISE-1 PUBLIC NOTIFICATION PROCESS

Prior to the start of ground disturbance, the project owner shall notify all residents within one mile of the project site and one-half mile of the linear facilities, by mail or by other effective means, of the commencement of project construction. At the same time, the project owner shall establish a telephone number for use by the public to report any undesirable noise conditions associated with the construction and operation of the project. If the telephone is not staffed 24 hours a 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, or a similarly effective telephone number, shall be posted at the project site during construction where it is visible to passersby. This telephone number shall be maintained until the project has been operational for at least one year.

Verification: At least 15 days prior to ground disturbance, the project owner shall transmit to the compliance project manager (CPM) a statement, signed by the project owner's project manager, stating that the above notification has been performed, and describing the method of that notification. This communication shall also verify that the telephone number has been established and posted at the site, and shall provide that telephone number.

NOISE-2 NOISE COMPLAINT PROCESS

Throughout the construction and operation of the project, the project owner shall document, investigate, evaluate, and attempt to resolve all legitimate project-related noise complaints[1]. The project owner or authorized agent shall:

- Use the Noise Complaint Resolution Form (below), or a functionally equivalent procedure acceptable to the CPM, to document and respond to each project-related noise complaint;
- Attempt to contact the person(s) making the noise complaint within 24 hours;
- Conduct an investigation to determine the source of noise in the complaint;
- If the noise is project related, take all feasible measures to reduce the source of the noise; and
- Submit a report documenting the complaint and actions taken. The report shall include: a complaint summary, including the final results of noise reduction efforts and, if obtainable, a signed statement by the complainant that states that the noise problem has been resolved to the complainant's satisfaction.

Verification: Within five days of receiving a legitimate noise complaint[2], the project owner shall file with the CPM a Noise Complaint Resolution Form, shown below, that documents the resolution of the complaint. If mitigation is required to resolve the complaint, and the complaint is not resolved within a three business-day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is implemented.

[1] A legitimate complaint refers to a complaint about noise that is caused by the HBEP project as opposed to another source (as verified by the CPM). A legitimate complaint constitutes a violation by the project of any noise condition of certification (as confirmed by the CPM), which is documented by an individual or entity affected by such noise.

[2] For the definition of "legitimate complaint", see the footnote in condition of certification **NOISE-2**.

NOISE-3 EMPLOYEE NOISE CONTROL PROGRAM

The project owner shall submit to the CPM for review and approval a noise control program. The noise control program shall be used to reduce employee exposure to high (above permissible) noise levels during construction in accordance to the applicable OSHA and Cal-OSHA standards.

<u>Verification:</u> At least 30 days prior to the start of ground disturbance, the project owner shall submit the noise control program to the CPM. The project owner shall make the program available to Cal-OSHA upon request.

NOISE-4 NOISE RESTRICTIONS

The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the operation of the project will not cause the noise levels due to normal steady-state plant operation alone, to exceed an hourly average of 61 dBA L_{50} measured at or near monitoring location M2.

Also, the project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the operation of the project will not cause the noise levels due to plant operation alone, during the four quietest consecutive hours of the nighttime, to exceed an average of 45 dBA L_{90} measured at or near monitoring location M3 and an average of 49 dBA L_{90} measured at or near monitoring location M4.

No new pure-tone components (as defined in **Noise Table A1**, below) shall be caused by the project. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints~~[3]~~.

When the project first achieves a sustained output of 85 percent or greater of its rated capacity, the project owner shall conduct a 25-hour community noise survey at monitoring locations M2, M3 and M4, or at a closer location acceptable to the CPM and include L_{50} and L_{90} readings. This survey shall also include measurement of one-third octave band sound pressure levels to ensure that no new pure-tone noise components have been caused by the project.

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 receptor locations to determine the presence of pure tones or other dominant sources of plant noise.

~~[3] For the definition of "legitimate complaint", see the footnote in condition of certification **NOISE-2**~~.

If the results from the noise survey indicate that the power plant noise at the affected receptor sites exceed the above values, 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 reduce the pure tones to a level that complies with **Noise Table A1**, below.

Verification: The above noise survey shall be conducted in two parts. Part one shall take place within 90 days of Power Block 1 (PB-1) first achieving a sustained output of 85 percent or greater of its rated capacity. Part 2 of this survey shall be performed within 90 days of Power Block 2 (PB-2) first achieving 85 percent or greater of its rated capacity and shall include the combined operation of PB-1 and PB-2 at 85 percent or greater of the overall plant rated capacity with all turbine generators operating. The exception to the above is that for the daytime portions of the survey only (between 7:00 a.m. and 10:00 p.m.) the above rated capacity can be 80 percent or higher rather than 85 percent or higher.

Within 15 days after completing each part, the project owner shall submit a summary report to the CPM. Included in the survey report shall be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limits, and a schedule, subject to CPM approval, for implementing these measures. When these measures are implemented and in place, the project owner shall repeat the noise survey.

Within 15 days of completion of the new survey, the project owner shall submit to the CPM a summary report of the new noise survey, performed as described above and showing compliance with this condition.

NOISE-5 OCCUPATIONAL NOISE SURVEY

Following PB-1's attainment of a sustained output of 90 percent or greater of its rated capacity, the project owner shall conduct an occupational noise survey to identify any noise hazardous areas in the facility. Following PB-2's attainment of a sustained output of 90 percent or greater of its rated capacity, the project owner shall repeat this survey.

The survey shall be conducted by a qualified person in accordance with the provisions of Title 8, California Code of Regulations, sections 5095-5099 (Article 105) and Title 29, Code of Federal Regulations, section 1910.95. The survey results shall be used to determine the magnitude of employee noise exposure.

The project owner shall prepare a report of the survey results and, if necessary, identify proposed mitigation measures to be employed in order to comply with the applicable California and federal regulations.

Verification: Within 30 days after completing each 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 from OSHA and Cal-OSHA.

NOISE-6 CONSTRUCTION RESTRICTIONS

Heavy equipment operation and noisy[~~4~~**3**] construction work relating to any project features, including pile driving, shall be restricted to the times delineated below:

Mondays through Saturdays:	7:00 a.m. to 8:00 p.m.
Sundays and Federal Holidays:	Construction not allowed

Limited construction activities may be performed outside of the above hours, with CPM approval as set forth below.

Haul trucks and other engine-powered equipment shall be equipped with adequate mufflers and other state-required noise attenuation devices. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use (jake braking) shall be limited to emergencies.

Verification: Prior to ground disturbance, the project owner shall transmit to the CPM a statement acknowledging that the above restrictions will be observed throughout the construction of the project.

In consultation with the CPM, construction equipment generating excessive noise[~~5~~**4**] shall be updated or replaced if beneficial in reducing the noise and if feasible. In addition, temporary acoustic barriers shall be installed around stationary construction noise sources if beneficial in reducing the noise and if feasible. The project owner shall reorient construction equipment, and relocate construction staging areas, when possible, to minimize the noise impact at nearest noise-sensitive receptors.

At least 10 days prior to any heavy equipment operation or noisy[~~6~~] construction activities that would occur outside of the above hours, the project owner shall submit a request to the CPM for review and approval and simultaneously send a copy to the City of Huntington Beach for review and comment. The project owner shall provide a copy of the transmittal letter to the City of Huntington Beach soliciting review and comment to the CPM.

The request submitted to the CPM shall specify the activities that need to occur outside of the restricted days and times set forth above; the need for such activities; the days, dates, and times during which these activities will occur; the approximate distance of activities to residential and sensitive receptors; the expected sound levels at these receptors; and a statement that the activities will be performed in a manner to ensure excessive noise is prohibited as much as practicable. At the same time, the project owner shall notify the residents and property owners within one-half mile of the project site of the request. In this notification, the project owner shall state that it will perform this activity in a manner to ensure excessive noise is prohibited as much as practicable.

[~~4~~3] ~~Noise~~ **"Noisy" means noise** that draws legitimate complaint (for the definition of "legitimate complaint", see the footnote in condition of certification **NOISE-2**)

[~~5~~4] ~~Noise~~ **"Excessive noise" means noise** that draws a legitimate complaint (for the definition of "legitimate complaint", see the footnote in condition of certification **NOISE-2**)

[~~6~~] ~~Noise that draws legitimate complaint (for the definition of "legitimate complaint", see the footnote in condition of certification **NOISE-2**)~~

The project owner shall not perform any heavy equipment operation or noisy[7] construction activities outside of the timeframes set forth above until the CPM has granted the request for exemption. If the exemption is granted, the project owner shall notify the residents and property owners within one-half mile of the project site of the approval of the request. The project owner shall provide copies to the CPM of all transmittal letters to property owners and residents.

NOISE-7 STEAM BLOW RESTRICTIONS

If a traditional, high-pressure steam blow process is used the project owner shall equip steam blow piping with a temporary silencer that quiets the noise of steam blows to no greater than 89 dBA measured at a distance of 50 feet. The steam blows shall be conducted between 8:00 a.m. and 6:00 p.m. A new high-pressure steam blow shall not be initiated after 5:00 p.m. If a low-pressure, continuous steam blow process is used, the project owner shall submit to the CPM a description of the process, with expected noise levels and planned hours of steam blow operation.

Verification: At least 15 days prior to the first steam blow, the project owner shall notify all residents or business owners within one mile of the project site boundary. The notification may be in the form of letters, phone calls, fliers, or other effective means, as approved by the CPM. The notification shall include a description of the purpose and nature of the steam blow(s), the planned schedule, expected sound levels, and explanation that it is a one-time activity and not part of normal plant operation.

NOISE-8 PILE DRIVING MANAGEMENT

The project owner shall perform pile driving in a manner to reduce the potential for any legitimate noise complaints. The project owner shall notify the residents in the vicinity of pile driving prior to start of pile driving activities.

Verification: At least 15 days prior to first pile driving, the project owner shall submit to the CPM a description of the pile driving technique to be employed, including calculations showing its projected noise impacts at monitoring locations M2-M4.

At least 10 days prior to first production pile driving, the project owner shall notify the residents within one-half mile of the pile driving. In this notification, the project owner shall state that it will perform this activity in a manner to reduce the potential for any legitimate noise complaints, as much as practicable. The project owner shall submit a copy of this notification to the CPM prior to the start of pile driving.

~~[7] Noise that draws legitimate complaint (for the definition of "legitimate complaint", see the footnote in condition of certification **NOISE-2**)~~

REFERENCES

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

NOISE COMPLAINT RESOLUTION FORM

Huntington Beach Energy Project
(12-AFC-02C)

NOISE COMPLAINT LOG NUMBER _________________________

Complainant's name and address:

Phone number: _________________________

Date complaint received: _________________________

Time complaint received: _________________________

Nature of noise complaint:

Definition of problem after investigation by plant personnel:

Date complainant first contacted: _________________________

Initial noise levels at 3 feet from noise source _________ dBA Date: ___________

Initial noise levels at complainant's property: __________ dBA Date: ___________

Final noise levels at 3 feet from noise source: ________ dBA Date: ___________

Final noise levels at complainant's property: __________ dBA Date: ___________

Description of corrective measures taken:

Complainant's signature: _________________________ Date: ___________

Approximate installed cost of corrective measures: $ ____________

Date installation completed: ____________

Date first letter sent to complainant: ____________ (copy attached)

Date final letter sent to complainant: ____________ (copy attached)

This information is certified to be correct:
Plant Manager's Signature: _________________________

(Attach additional pages and supporting documentation, as required).

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)

Petition to Amend Final Commission Decision

PUBLIC HEALTH

Huei-An (Ann) Chu, Ph. D.

SUMMARY OF CONCLUSIONS

California Energy Commission staff has analyzed the potential human health risks associated with construction, demolition and operation of the petition to amend (PTA) the Final Decision for Huntington Beach Energy Project (HBEP, 12-AFC-02). Given the scope of the changes proposed in the PTA, staff's analysis of potential health impacts of the HBEP was done as if HBEP was a new project, and based on a conservative health protective methodology that accounts for impacts to the most sensitive individuals in a given population. Staff concludes that there would be no significant health impacts from the HBEP's potential toxic air contaminant (TAC) emissions. Staff also concludes that the proposed modification would not affect the HBEP's ability to comply with applicable health 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 no supplementation is necessary and the Committee can rely on the analysis and conclusions of the Decision with regards to Public Health and does not need to reanalyze them.

INTRODUCTION

On June 27, 2012, AES Southland, LLC, submitted an Application for Certification (AFC) for the HBEP. On October 29, 2014, the Energy Commission approved the AFC for HBEP with a Final Decision. On September 14, 2015, AES Southland, LLC, submitted to the Energy Commission a PTA the Final Decision for HBEP (12-AFC-02).

The project modifications proposed by this PTA related to Public Health include (HBEP 2015a, Section 1.2 and Section 2.0, HBEP 2016n, Section 5.1.1):

- The Amended HBEP would be constructed on 30 acres entirely within the site of the existing Huntington Beach Generating Station (HBGS) in Huntington Beach, California.
- The combustion turbine combined-cycle (CTCC) power block (Block 1) would include two General Electric (GE) Frame 7FA.05 combustion turbine generators (CTG) with unfired heat recovery steam generators (HRSGs), one steam turbine generator, an air-cooled condenser, a natural-gas-fired auxiliary boiler, and related ancillary equipment, with nominal summer capacity of 644 megawatts (MWs) net.
- The simple-cycle power block (Block 2) would include two GE LMS-100 simple-cycle combustion turbine generators, with a nominal capacity of 200 MWs net.

- Construction of the Amended HBEP CTCC units (Block 1) would require the demolition of the existing Huntington Beach Generating Station HBGS Unit 5, two former fuel oil tanks and associated fuel oil pipelines and containment berms. Demolition of Unit 5 is scheduled to occur in 2016 under the already approved Final Decision. Construction of Block 1 is expected to take approximately 35 months (including commissioning), with construction scheduled to occur from the second quarter of 2017 through the second quarter of 2020.
- Construction of the Amended HBEP simple-cycle CTG units (Block 2) would require the retirement and demolition of existing HBGS Units 3 and 4. Demolition of existing HBGS Units 3 and 4 is not part of the Amended HBEP project description.
- In addition to the construction of the new generating units, upon the commercial operation of the Amended HBEP simple-cycle power block, existing HBGS Units 1 and 2 would be decommissioned and demolished to their turbine deck. HBGS Unit 1 would be retired in the fourth quarter of 2019 to provide interconnection capacity for the new CTCC units. HBGS Unit 2 would be retired either after commercial operation of the HBEP simple-cycle CTG or at the final compliance deadline for once-through-cooling intake structures.

The purpose of this Preliminary Staff Assessment (PSA) is to determine if emissions of TACs from the Amended HBEP would have the potential to cause significant adverse public health impacts or to violate standards for the protection of public health. If potentially significant health impacts are identified, staff would identify and recommend mitigation measures necessary to reduce such impacts to insignificant levels.

In addition to the analysis contained in this Public Health section that focuses on potential effects to the public from emissions of TACs, Energy Commission staff address the potential impacts of regulated, or criteria, air pollutants in the Air Quality section of this PSA, and assess the health impacts on public and workers from accidental releases of hazardous materials in the Hazardous Materials Management and Worker Safety and Fire Protection sections. The health and nuisance effects from electric and magnetic fields are discussed in the Transmission Line Safety and Nuisance section. Pollutants released from the project's wastewater streams are discussed in the Soil and Surface Water and Water Supply sections. Releases in the form of hazardous and nonhazardous wastes are described in the Waste Management section.

SUMMARY OF THE DECISION

The Energy Commission made the following findings for HBEP (CEC 2014bb):

1. Demolition, construction, and operation of the project will result in the routine release of criteria and noncriteria pollutants that have the potential to adversely impact public health.

2. Emissions of criteria pollutants, as discussed in the Air Quality section of this Decision, will be mitigated to levels consistent with applicable state and federal standards.

3. Emissions of noncriteria pollutants or toxic air contaminants are assessed according to procedures developed by state and federal regulatory agencies to evaluate potential health effects to protect the most sensitive individuals in the population.

4. The accepted method used by state and federal regulatory agencies in assessing the significance for both acute and chronic non-carcinogenic public health effects of noncriteria pollutants is known as the hazard index method. A similar method is used for assessing the significance of potential carcinogenic effects based on incremental exposure levels.

5. The evidence contains a screening level health risk assessment of the project's potential health effects due to emissions of TACs.

6. The health risk assessment is based on worst case assumptions using the highest emission factors, assuming the worst weather conditions, and calculating effects at the point of maximum impact, so that actual risks are expected to be much lower at any other location.

7. Exposure to diesel particulate emissions from construction equipment will not result in long-term carcinogenic or non-carcinogenic health effects with the implementation of the conditions of certification set forth in the Air Quality section of this Decision.

8. Exposure to demolition and construction-related diesel particulates will be mitigated to the extent feasible by implementing measures to reduce equipment emissions.

9. Exposure to particulates in fugitive dust due to demolition, excavation, and construction activities will be mitigated to insignificant levels by implementing measures to reduce dust production and dispersal.

10. The health risk assessment for exposure to TAC emissions during project operations confirmed that acute and chronic calculated risks fall below the significance level of 1.0, and that the cancer risk is below the significance level of 10 in one million.

11. Cumulative impacts from noncriteria pollutants were analyzed in accordance with CEQA requirements and are not expected to be significant.

12. Since the project's contributions to health risks are well below the significance level, the project is not expected to contribute significantly to a cumulative health impact.

13. Members of the public potentially exposed to toxic air contaminant emissions of this project—including sensitive receptors such as the elderly, infants, and people with pre-existing medical conditions—will not experience any acute or chronic significant health risk or any significant cancer risk as a result of that exposure.

14. Environmental justice populations will not be adversely affected by the construction and operation of the project.

The Commission made the following conclusions, and proposed no conditions of certification:

1. Emissions of noncriteria pollutants from the construction and operation of the HBEP do not pose a significant direct, indirect, or cumulative adverse public health risk.

2. The project will comply with the applicable LORS specified herein.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

No LORS applicable to the project have changed since the Commission Decision was published in October 2014. This section evaluates compliance with these requirements and summarizes the applicable LORS.

Public Health Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Federal	
Clean Air Act section 112 (Title 42, U.S. Code section 7412)	Section 112 of the Clean Air Act addresses emissions of hazardous air pollutants (HAPs). This act requires new sources that emit more than 10 tons per year of any specified HAP or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology (MACT).
40 Code of Federal Regulations (CFR) Part 63 Subpart YYYY (National Emission Standard for Hazardous Air Pollutants for Stationary Combustion Turbines)	This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility with emissions of 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit.
40 Code of Federal Regulations (CFR) Part 68 (Risk Management Plan)	This rule requires facilities storing or handling significant amounts of acutely hazardous materials to prepare and submit Risk Management Plans.
State	
California Health and Safety Code section 25249.5 et seq. (Proposition 65)	These sections establish thresholds of exposure to carcinogenic substances above which Proposition 65 exposure warnings are required.
California Health and Safety Code, Article 2, Chapter 6.95, Sections 25531 to 25541; California Code of Regulations (CCR) Title 19 (Public Safety), Division 2 (Office of Emergency Services), Chapter 4.5 (California Accidental Release Prevention Program)	These regulations require facilities storing or handling significant amounts of acutely hazardous materials to prepare and submit Risk Management Plans.
California Health and Safety Code section 41700	This section states that “no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property.”

Applicable LORS	Description
California Health and Safety Code Sections 44300 et seq.	Air Toxics Hot Spots Program requires participation in the inventory and reporting program at the local air pollution control district level.
California Health and Safety Code Sections 44360 to 44366 (Air Toxics “Hot Spots” Information and Assessment Act—AB 2588)	This act requires that based on results of a health risk assessment (HRA) conducted per the California Air Resources Board (ARB) / OEHHA (Office of Environmental Health Hazard Assessment) guidelines, toxic contaminants do not exceed acceptable levels.
California Public Resource Code section 25523(a); Title 20 California Code of Regulations (CCR) section 1752.5, 2300–2309 and Division 2 Chapter 5, Article 1, Appendix B, Part (1); California Clean Air Act, Health and Safety Code section 39650, et seq.	These laws and regulations require a quantitative health risk assessment for new or modified sources, including power plants that emit one or more TACs.
Local	
South Coast Air Quality Management District (SCAQMD) Rule 1401 (New Source Review of Toxic Air Contaminants)	This rule specifies limits for maximum individual cancer risk (MICR), cancer burden, and noncancer acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permit units which emit TACs.
SCAQMD Rule 1403 (Asbestos Emissions from Demolition/Renovation Activities)	This rule specifies work practice requirements to limit asbestos emissions from building demolition and renovation activities, including the removal and associated disturbance of asbestos-containing materials.
SCAQMD Rule 212(c)(3) (Permits – Public Notice)	This rule requires public notification if the MICR, based on Rule 1401, exceeds one in 1 million (1×10^{-6}), due to a project’s proposed construction, modification, or relocation for facilities with more than one permitted source unless the applicant can show the total facility-wide MICR is below 10 in 1 million (10×10^{-6}).

ENVIRONMENTAL IMPACT ANALYSIS

Characteristics of the natural environment, such as meteorology and terrain, affect the project’s potential for impacts on public health. An emission plume from a facility would affect elevated areas before lower terrain areas because of reduced opportunity for atmospheric mixing. Consequently, areas of elevated terrain located near a project site can often be subjected to increased pollutant impacts compared to lower-level areas. Also, the land use around a project site can influence impacts due to population distribution and density, which, in turn, can affect public exposure to project emissions. Additional factors affecting potential public health impacts include existing air quality and environmental site contamination. Because of the change in project technologies, the update the human health risk assessment guideline and software, it was necessary to redo the public health analysis.

SETTING

The Amended HBEP site is located in the city of Huntington Beach at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (Highway 1) and Newland Street, within the SCAQMD. Huntington Beach is a seaside city in Orange County in Southern California. The project is located on the site of the existing Huntington Beach Generating Station HBGS, an operating power plant. The HBEP site is bounded on the west by a manufactured home/recreational vehicle park, on the north by a tank farm, on the north and east by the Huntington Beach Channel and residential areas, on the southeast by the Huntington Beach Wetland Preserve/Magnolia Marsh wetlands, and to the south and southwest by the Huntington Beach State Park and the Pacific Ocean. The site is located on a gently sloping coastal plain (HBEP 2012a, section 5.9). The setting has not changed from the setting of the previously approved project.

The approved HBEP was proposed as a 939-MW power plant consisting of two independently operating, three-on-one combined-cycle combustion turbine power blocks. Each power block would have consisted of three natural gas-fired CTGs, three supplemental-fired HRSGs, one steam turbine generator (STG), an air-cooled condenser, and related ancillary equipment (HBEP 2015a, Section 1.1). The Amended HBEP differs from the Licensed HBEP in key ways. The Amended HBEP is proposed as an 844-MW (net), natural gas fired power plant with a combined-cycle unit with an air-cooled condenser and two and simple-cycle units, to be located on the site of the existing Huntington Beach Generating Station in Huntington Beach, California.

Sensitive receptors, such as infants, the aged, and people with specific illnesses or diseases, are the subpopulations which are more sensitive to the effects of toxic substance exposure. According to the PTA, approximately 353,173 residents live within a 6-mile radius of the site proposed for HBEP, and the sensitive receptors within a 6-mile radius of the project site include (HBEP 2015a, section 5.9.2):

- 275 preschool/daycare centers
- 12 nursing homes
- 81 schools
- 579 hospitals, clinics, and/or pharmacies
- 7 colleges

The nearest sensitive receptor is a daycare facility located 0.3 mile east of the project site. The nearest school is Edison High School, located approximately 0.5 mile to the northeast of the project site. The nearest residence is located approximately 250 feet west-northwest of the facility along Newland Street. The nearest businesses are located along Edison Drive, just north of the project site (HBEP 2015a, section 5.9.2). As discussed above, the changes in source-receptor relationship due to the changed facility design requires a new analysis which is presented in a later portion of this section.

METEOROLOGY AND CLIMATE

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into the air and the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants along with the associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced, and localized exposures may be increased.

Atmospheric stability is one characteristic related to turbulence, or the ability of the atmosphere to disperse pollutants from convective air movement. Mixing heights (the height marking the region within which the air is well mixed below the height) are lower during mornings because of temperature inversions. These heights increase during warm afternoons. Staff's Air Quality section presents a more detailed description of meteorological data for the area.

The climate of the South Coast Air Basin is mild, tempered by cool sea breezes. The area's climatic conditions are strongly influenced by its terrain and geographical location. The basin is a coastal plain with connecting broad valleys and low hills, bounded by the Pacific Ocean in the southwest quadrant with high mountains forming the remainder of the perimeter. The general region lies in the semi-permanent high pressure zone of the eastern Pacific. This usually mild climatological pattern is interrupted infrequently by periods of extremely hot weather, winter storms, or Santa Ana winds (HBEP 2012a, section 5.1.3.2).

The annual and quarterly wind rose plots (from 2010 to 2014) for the National Weather Service John Wayne Airport meteorological station[1] show that the prevailing winds that blow to the Amended HBEP site were mostly from the southwest. Only a small percent of prevailing winds blowing to the Amended HBEP site were from other directions (HBEP 2015a, Section 5.1.5.2 and Appendix 5.1C). The metrological data used for this analysis covered the years from 2010 to 2014 while the Licensed HBEP used observations made during earlier years (from 2008 to 2012). Please refer to the **AIR QUALITY** section for more details.

EXISTING PUBLIC HEALTH CONCERNS

By examining average toxic concentration levels from representative air monitoring sites, together with cancer risk factors specific to each carcinogenic contaminant, a lifetime cancer risk can be calculated to provide a background risk level for inhalation of ambient air.

[1] A wind rose plot is a diagram that depicts the distribution of wind direction and speed at a location over a period of time.

This analysis is prepared in order to identify the most current status of respiratory diseases (including asthma), cancer, and childhood mortality rates in the population located within the same county or air basin of the amended project site. Such assessment of existing health concerns provides staff with a basis on which to evaluate the significance of any additional health impacts from the Amended HBEP and assess the need for further mitigation. The public health information below is the most current available and is updated from the previous analysis.

Cancer

When examining such risk estimates, staff considers it important to note that the overall lifetime risk of developing cancer for the average male in the United States is about 1 in 2, or 500,000 in 1 million and about 1 in 3, or 333,333 in 1 million for the average female (American Cancer Society 2014).

From 2007 to 2011, the cancer incidence rates in California were 49.92 in 1 million for males and 39.63 for females. Also, from 2007 to 2011, the cancer death rates for California were 18.68 in 1 million for males and 13.73 in 1 million for females (American Cancer Society, Cancer Facts & Figures 2015).

By examining the State Cancer Profiles presented by the National Cancer Institute, staff found that cancer death rates in Orange County have been falling between 2008 and 2012. These rates (of 14.63 per 1,000,000, combined male/female) were somewhat lower than the statewide average of 15.51 per 1,000,000 (National Cancer Institute 2013).

According to the County Health Status Profiles 2015, the death rate due to all cancers, from 2011-2013, is 14.51 in 1 million for Orange County, slightly lower than the cancer death rate (15.09 in 1 million) for California (CDPH 2015).

Lung Cancer

As for lung and bronchus cancers, from 2007 to 2011 the cancer incidence rates in California were 5.8 in 1 million for males and 4.31in 1 million for females. Also, from 2007 to 2011, the cancer death rates for California were 4.55 in 1 million for males and 3.15 in 1 million for females (American Cancer Society, Cancer Facts & Figures 2015).

According to the County Health Status Profiles 2015, the death rate due to lung cancers, from 2011-2013, is 3.16 in 1 million for Orange County, slightly lower than the cancer death rate (3.36 in 1 million) for California (CDPH 2015).

Asthma

The asthma diagnosis rates in Orange County are lower than the average rates in California for both adults (age 18 and over) and children (ages 1-17). The percentage of adults in Orange County diagnosed with asthma was reported as 6.0 percent in 2005-2007, compared to 7.7 percent for the general California population. Rates for children for the same 2005-2007 period were reported as 9.5 percent in Orange County compared to 10.1 percent for the state in general (Wolstein et al., 2010).

Air Toxics Emission Estimates

As a follow-up to the Multiple Air Toxics Exposure Study II and III (MATES II and III), SCAQMD commenced a fourth MATES study (MATES IV) in 2012. After the approval of the previous project, the final report of MATES IV was published in May 1, 2015. The results of MATES IV study show a continuing downward trend in TACs. The comparison of county-wide population-weighted risk in Table 4-5 in the final report of MATES IV shows TAC reductions that occurred in Orange County, with values decreasing from 781 per million in 2005 to 315 per million in 2012. South Coast Air Basin (SCAB) data follow the same trend, with corresponding TACs decreasing from 853 per million in 2005 to 367 per million in 2012 (MATES IV, 2015).

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff conducts its public health analysis by evaluating the information and data provided in the PTA by the project owner. Staff also relies upon the expertise and guidelines of the California Environmental Protection Agency (Cal/EPA) Office of Environmental Health Hazard Assessment (OEHHA) in order to identify: (1) contaminants that cause cancer or other noncancer health effects, and (2) the toxicity, cancer potency factors and non-cancer RELs of these contaminants. Staff relies upon the expertise of the ARB and the local air districts to conduct ambient air monitoring of TACs and on the California Department of Public Health to evaluate pollutant impacts in specific communities. It is not within the purview or the expertise of the Energy Commission staff to duplicate the expertise and statutory responsibility of these agencies. The HRA process addresses three categories of health impacts: (1) acute (short-term) health effects, (2) chronic (long-term) noncancer effects, and (3) cancer risk (also long-term). This approach is consistent with the previous analysis. However, OEHHA's Air Toxics Hot Spots Program Guidance Manual for the Preparation of Risk Assessments (Guidance Manual) was updated March 6th, 2015 (OEHHA 2015). Also, a newer computer program, the Hot Spots Analysis and Reporting Program 2 (HARP2), has been developed by ARB as a tool to implement the risk assessments as outlined in this guidance manual (ARB 2016a).

Acute Noncancer Health Effects

Acute health effects are those that result from short-term (one-hour) exposure to relatively high concentrations of pollutants. Such effects are temporary in nature and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic Noncancer Health Effects

Chronic noncancer health effects are those that result from long-term exposure to lower concentrations of pollutants. Long-term exposure has been defined as more than 12 percent of a lifetime, or about 8 years (OEHHA 2003, p. 6-5). Chronic noncancer health effects include diseases such as reduced lung function and heart disease.

Reference Exposure Levels (RELs)

The analysis for both acute and chronic noncancer health effects compares the maximum project contaminant levels to safe levels known as Reference Exposure Levels, or RELs. These are amounts of toxic substances to which even sensitive individuals could be exposed without suffering any adverse health effects (OEHHA 2003, p. 6-2). These exposure levels are specifically designed to protect the most sensitive individuals in the population, such as infants, the aged, and people with specific illnesses or diseases which make them more sensitive to the effects of toxic substance exposure. The RELs are based on the most sensitive adverse health effect reported in the medical and toxicological literature and include specific margins of safety. The margins of safety account for uncertainties associated with inconclusive scientific and technical information available at the time of setting the REL. They are therefore meant to provide a reasonable degree of protection against hazards that research has not yet identified.

Concurrent exposure to multiple toxic substances would result in health effects that are equal to, less than, or greater than effects resulting from exposure to the individual chemicals. Only a small fraction of the thousands of potential combinations of chemicals have been tested for the health effects of combined exposures. In conformity with California Air Pollution Control Officers Association guidelines, the HRA assumes that the effects of each substance are additive for a given organ system (OEHHA 2003, pp. 1-5, 8-12). Other possible mechanisms due to multiple exposures include those cases where the actions would be synergistic or antagonistic (where the effects are greater or less than the sum, respectively). For these types of exposures, the health risk assessment could underestimate or overestimate the risks.

Cancer Risks

For carcinogenic substances, the health assessment considers the risk of developing cancer and assumes that continuous exposure to the carcinogen would occur over a 70-year lifetime[2]. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound estimate based on the worst-case assumptions.

Cancer Potency Factors

Cancer risk is expressed in terms of the number of chances per million of developing cancer. It is a function of the maximum expected pollutant concentration, the probability that a particular pollutant would cause cancer (called a potency factor), and the length of the exposure period. Cancer risks for individual carcinogens are added together to yield a total cancer risk for each potential source. The conservative nature of the screening assumptions used means that the actual cancer risks from project emissions would be considerably lower than estimated.

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[2] In 2015 Guidance, OEHHA recommends that an exposure duration (residency time) of 30 years be used to estimate individual cancer risk for the maximally exposed individual resident (MEIR). In addition, for the maximally exposed individual worker (MEIW), OEHHA now recommends using an exposure duration of 25 years to estimate individual cancer risk for off-site workers (OEHHA 2015, Table 8.5).

As previously noted, the screening analysis is performed to assess the worst-case risks to public health associated with the amended project. If the screening analysis were to predict a risk below significance levels, no further analysis would be necessary and the source would be considered acceptable with regard to carcinogenic effects. If however, the risk were to be above the significance level, then further analysis using more realistic site-specific assumptions would be performed to obtain a more accurate estimate.

Significance Criteria

Energy Commission staff assesses the maximum cancer impacts from specific carcinogenic exposures by first estimating the potential impacts on the maximally exposed individual. This is a person hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using the worst-case assumptions. Since the individual's exposure would produce the maximum impacts possible around the source, staff uses this risk estimate as a marker for acceptability of the project's carcinogenic impacts. This approach is consistent with the previous analysis.

Acute and Chronic Noncancer Health Risks

Non-criteria pollutants are evaluated for short-term (acute) and long-term (chronic) non-cancer health effects, and the noted cancer impacts from long-term exposures. The significance of project-related impacts is determined separately for each of the three health effects categories. Staff assesses the noncancer health effects by calculating a hazard index. A hazard index is a ratio obtained by comparing exposure from facility emissions to the safe exposure level (i.e. REL) for that pollutant. A ratio of less than 1.0 suggests that the worst-case exposure would be below the limit for safe levels and would thus be insignificant with regard to health effects. The hazard indices for all toxic substances with the same type of health effect are added together to yield a Total Hazard Index for the source. The Total Hazard Index is calculated separately for acute effects and chronic effects. A Total Hazard Index of less than 1.0 would indicate that cumulative worst-case exposures would not lead to significant noncancer health effects. In such cases, noncancer health impacts from project emissions would be considered unlikely even for sensitive members of the population. Staff would therefore conclude that there would be no significant noncancer project-related public health impacts. This assessment approach is consistent with risk management guidelines of both the California OEHHA and the U.S. Environmental Protection Agency (EPA).

Cancer Risk

Staff relies upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986, (Health & Safety Code, §§25249.5 et seq.) for guidance in establishing significance levels for carcinogenic exposures. Title 22, California Code of Regulations section 12703(b) states that "the risk level which represents no significant risk shall be one which is calculated to result in one or less excess cancer cases within an exposed population of 100,000, assuming lifetime exposure." This risk level is equivalent to a cancer risk of 10 in 1 million, which is also written as 10×10^{-6}. In other words, under state regulations, an incremental cancer risk greater than 10 in 1 million from a project should be regarded as suggesting a potentially significant carcinogenic impact on public health. The 10 in 1million risk level is also used by the Air Toxics "Hot Spots" (AB 2588) program as the public notification threshold for air toxic emissions from existing sources.

An important distinction between staff's approach and the Proposition 65 risk characterization approach is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the total risk from all the cancer-causing pollutants to which the individual might be exposed in the given case. Thus, the manner in which the significance level is applied by staff is more conservative (health-protective) than the manner applied by Proposition 65. The significant risk level of 10 in 1 million is also consistent with the level of significance adopted by many California air districts. In general, these air districts would not approve a project with a cancer risk estimate more than 10 in 1 million.

As noted earlier, the initial risk analysis for a project is typically performed at a screening level, which is designed to overstate actual risks, so that health protection could be ensured. Staff's analysis also addresses potential impacts on all segments of the population, including the young, the elderly, and people with existing medical conditions, that would render them more sensitive to the adverse effects of toxic air contaminants and any minority or low-income populations that are likely to be disproportionately affected by impacts. To accomplish this goal, staff uses the most current acceptable public health exposure levels (both acute and chronic) set to protect the public from the effects of air toxics being analyzed. When a screening analysis shows the cancer risks to be above the significance level, refined assumptions would be applied for likely a lower, more realistic risk estimate. If, after using refined assumptions, the project's risk is still found to exceed the significance level of 10 in 1 million, staff would require appropriate measures to reduce the risk to less than significant levels. If, after all feasible risk reduction measures have been considered and a refined analysis still identifies a cancer risk of greater than 10 in 1 million, staff would deem such a risk to be significant and would not recommend project approval.

AMENDED PROJECT'S CONSTRUCTION/DEMOLITION IMPACTS AND MITIGATION MEASURES

The construction and demolition period for Amended HBEP would be approximately 10 years or 120 months (HBEP 2015a, Table 2.2-1), longer than the approved HBEP (7.5 years). The potential construction/demolition risks are normally associated with exposure to asbestos, fugitive dust, and combustion emissions (i.e. diesel exhaust).

Asbestos

The demolition of buildings containing asbestos could cause the emission of asbestos particles. The mitigation measures needed to reduce the impacts of asbestos, asbestos containing materials (ACM), and other hazardous wastes from the construction or demolition phases of the project are covered in the Waste Management section. As for asbestos, conditions of certification **WASTE-2** requires that the project owner submit the SCAQMD Asbestos Notification Form to SCAQMD and the Energy Commission for review and approval prior to removal and disposal of asbestos. This program ensures there will be no release of asbestos that could impact public health and safety. Please refer to staff's **WASTE MANAGEMENT** section for detailed mitigation measures regarding the construction/demolition of asbestos and ACM, and information on the safe handling and disposal of these and all project-related wastes.

Fugitive Dust

Fugitive dust is defined as dust particles that are introduced into the air through certain activities such as soil cultivation, vehicles operating on open fields, or dirt roadways. Fugitive dust emissions during construction of the amended project could occur from:

- Dust entrained during site preparation and grading/excavation at the construction and demolition sites;
- Dust entrained during onsite movement of construction vehicles on unpaved surfaces;
- Fugitive dust emitted from an onsite concrete batch plant; and
- Wind erosion of areas disturbed during construction activities.

The effects of fugitive dust on public health are covered in the Air Quality section, which includes staff's recommended mitigation measures, including **AQ-SC3** (Construction Fugitive Dust Control) and **AQ-SC4** (Dust Plume Response Requirement) to prevent fugitive dust plumes from leaving the project boundary. As long as the dust plumes are kept from leaving the project site, there will be no significant concern of fugitive dust adversely affecting public health.

Diesel Exhaust

Emissions of combustion byproducts during construction would result from:

- Exhaust from diesel construction equipment used for site preparation, grading, excavation, trenching, and construction of onsite and offsite (transmission- and gas pipeline-related) structures and from demolition activities;
- Exhaust from water trucks used to control construction/demolition dust emissions;
- Exhaust from portable welding machines, small generators, and compressors;
- Exhaust from diesel trucks used to transport workers and deliver concrete, fuel, and construction supplies to construction/demolition areas; and
- Exhaust from vehicles used by construction/demolition workers to commute to and from the project areas.

Construction Health Risk Assessment (HRA) for Diesel Exhaust

The primary air toxic pollutant of concern from construction/demolition activities is diesel particulate matter (DPM). A screening construction HRA for DPM was conducted by the project owner to assess the potential impacts associated with diesel emissions during the construction and demolition activities at HBEP. The construction HRA was performed for a shorter exposure duration and different receptor locations. The total DPM exhaust emissions were averaged over the demolition and construction period (i.e. 120 months) and spatially distributed in: (1) the site's eastern area, which is associated with the demolition of HBGS Unit 5, preparation of the former Plains All American tank farm area, and construction of the combined-cycle power block; (2) the site's western area, which is associated with construction of the simple-cycle power block; and (3) the site's southern area, which is associated with demolition of HBGS Units 1 and 2 (HBEP 2015a, Section 5.9.3.1).

The project owner did not run the HARP2 model to evaluate construction-related public health impacts, but rather took the maximum locations from DPM modeling and hand calculated the results. The maximum modeled annual average concentration of diesel particulate matter calculated by the project owner was 0.01027μg/m^3 (HBEP 2015a, Appendix 5.9B, Table 5.9B.3).

The demolition/construction HRA estimated the rolling cancer risks for each 10-year period during a 30-year exposure duration (starting with exposure during the third trimester of pregnancy) for residential exposure and a 10-year exposure duration (from age 16 to 25) for worker exposure, aligned with the expected construction duration, at the Point of Maximum Impact (PMI), Maximum Exposed Individual Resident (MEIR), Maximum Exposed Individual Worker (MEIW), and maximum exposed sensitive receptor. The excess cancer risks were estimated using the following (HBEP 2016n, Section 5.9.3.2):

- Equations 5.4.1.1 and 8.2.4A from the *Air Toxic Hot Spots Guidance Manual for Preparation of Health Risk Assessments* (OEHHA, 2015) for residential exposure.
- Equations 5.4.1.2A, 5.4.1.2B, and 8.2.4B from the *Air Toxic Hot Spots Guidance Manual for Preparation of Health Risk Assessments* (OEHHA, 2015) for worker exposure. Staff only evaluates the health impact on off-site workers because on-site workers are protected by Cal OSHA and are not required to be evaluated under the Hot Spots Program, unless the worker also lives on the facility site or property (OEHHA 2003, Chapter 8, pp. 8-5 and 8-6).
- The maximum annual ground-level concentrations used to estimate risk were determined through dispersion modeling with AERMOD.
- The AERMOD modeling approach for the HRA was consistent with that used for the criteria pollutant modeling analysis, except that the receptor grid for the HRA included census and sensitive receptors and excluded receptors located within the AES-controlled property.
- The demolition/construction emission estimates modeled are presented in Table 5.9-1 of PTA.

Chronic risks were also estimated for the PMI, MEIR, MEIW, and maximum exposed sensitive receptor, based on the same emission rates and ground-level concentrations described above. To calculate chronic risk, as characterized by a health index, the maximum annual ground-level concentration was divided by the DPM Reference Exposure Level of 5 micrograms per cubic meter (µg/m3) (OEHHA 2015).

Staff reviewed the project owner's analysis and the results are contained in **Public Health Table 2** (HBEP 2015a, Section 5.9.3.2, Table 5.9B.3, Table 5.9B.4, Table 5.9B.5 and Table 5.9B.6). Staff also included the results of the 2014 final staff assessment (FSA) for HBEP for comparison, shown as "2014 FSA for Licensed HBEP" in the table below (CEC 2014d). The results show the excess cancer risk at the PMI, MEIR, the highest value at a sensitive receptor, and MEIW are 5.22 in a million, 4.23 in a million, 0.48 in a million and 0.25 in a million, respectively, all less than the Energy Commission staff's significant impact threshold of 10 in a million. The predicted chronic health index at the PMI, MEIR, the highest value at a sensitive receptor, and MEIW are 0.0021, 0.0017, 0.00019, and 0.0021, respectively. The chronic hazard indices for diesel exhaust during construction/demolition activities are all lower than the significance level of 1.0. This means that there would be no chronic non-cancer impacts expected from construction/demolition activities (HBEP 2015a, Section 5.9.3.2). They all show lower values than the Licensed HBEP.

Public Health Table 2
Construction Hazard/Risk from DPMs calculated by the Project owner

	Receptor Type	Risk Value		Significance Level	Significant ?
		2014 FSA for Licensed HBEP	2015 PTA for Amended HBEP		
Derived Cancer Risk (per million)	PMI	12.3	5.22	10	No
	MEIR	3.5	4.23	10	No
	at a Sensitive Receptor	1.86	0.48	10	No
	MEIW	11	0.25	10	No
Chronic HI (dimensionless)	PMI	0.0461	0.0021	1	No
	MEIR	0.0131	0.0017	1	No
	MEIW	0.115	0.0021	1	No
	at a Sensitive Receptor	-	0.00019	1	No

Sources: HBEP 2015a, Section 5.9.3.2, Table 5.9B.3, Table 5.9B.4, Table 5.9B.5 and Table 5.9B.6 and CEC 2014d.

Based on the results of project owner's and staff's analyses, and considering the following two additional factors: (1) the potential exposure of DPM would be sporadic and limited in length and (2) the predicted incremental increase in cancer risk at the MEIR and MEIW and chronic health index at the PMI, MEIR, and MEIW are each less than the significance thresholds of 10 in one million and 1.0, respectively, staff concludes that impacts associated with the DPM from anticipated HBEP construction and demolition activities would be less than significant.

Conditions of certification **AQ-SC5** (Diesel-Fueled Engine Control) and **AQ-SC6** in the Air Quality section would ensure that cancer-related impacts of diesel exhaust emissions for the public and off-site workers are mitigated during construction/ demolition activities to a point where they are not considered significant. The potential levels of criteria pollutants from operation of construction/demolition equipment are discussed in staff's Air Quality section along with mitigation measures and related conditions of certification. The pollutants of most concern in this regard are particulate matter (PM), carbon monoxide (CO), sulfur dioxide (SO_2), and nitrogen dioxide (NO_2).

AMENDED PROJECT'S OPERATIONAL IMPACTS AND MITIGATION MEASURES

Table 5.9-2 and Table 5.9-3 of the PTA (HBEP 2016n) list the specific non-criteria pollutants that would be emitted as combustion byproducts from the combustion turbines (i.e. two GE 7FA.05s and two LMS-100 PBs) and one auxiliary boiler. Air toxics emission factors for the combustion turbines and the auxiliary boiler were provided by SCAQMD, with the exception of ammonia. For combustion turbines, the ammonia emission factor was based on an operating exhaust ammonia limit of 5 parts per million by volume (ppmv) at 15 percent oxygen and an F-factor of 8,710 (Note: an F-factor is the ratio of the carbon dioxide generated by the combustion of a given fuel to the amount of heat produced.) For the auxiliary boiler, the ammonia emission factor was based on an operating exhaust ammonia limit of 5 ppmv at 3 percent oxygen and an F-factor of 8,710. Additionally, polycyclic aromatic hydrocarbons (PAH) emissions were conservatively assumed to be controlled up to 50 percent through the use of an oxidation catalyst (EPA, 2000), which is proposed for use with both the GE 7FA.05s and GE LMS-100PBs (HBEP 2016n, Section 5.9.3.1).

The health risk from exposure to each project-related pollutant is assessed using the "worst case" emission rates and impacts. Maximum hourly emissions are used to calculate acute (one-hour) noncancer health effects, while estimates of maximum emissions on an annual basis are used to calculate cancer and chronic (long-term) noncancer health effects.

Hazard Identification

Numerous health effects have been linked to exposure to TACs, including development of asthma, heart disease, Sudden Infant Death Syndrome (SIDS), respiratory infections in children, lung cancer, and breast cancer (OEHHA 2003). According to the HBEP PTA, the major toxic air contaminants emitted from the operation of the combustion turbines and auxiliary boiler include acetaldehyde, acrolein, ammonia, benzene, 1,3-buadine, ethylbenzene, formaldehyde, napthalene, polycyclic aromatics, propylene oxide, toluene and xylene. **Public Health Table 3** and **Public Health Table 4** list each such pollutant.

Public Health Table 3
The Main Pollutants Emitted from the Amended Project

Criteria Pollutants	Non-criteria Pollutants
Carbon monoxide (CO)	Acetaldehyde
Oxides of nitrogen (NO_x)	Acrolein
Particulate matter (PM10 and PM2.5)	Ammonia
Oxides of sulfur (SO_2)	Benzene
Volatile Organic Compounds (VOCs)	1,3-Butadiene
	Ethylbenzene
	Formaldehyde
	Naphthalene
	Polycyclic Aromatic Hydrocarbons (PAHs, as BaP[a])
	Propylene oxide
	Toluene
	Xylene

Source: HBEP 2016n, Table 5.9-2 and Table 5.9-3
[a] Benzo[a]pyrene

Public Health Table 4
Types of Health Impacts and Exposure Routes Attributed to Toxic Emissions

Substance	Oral Cancer	Oral Noncancer	Inhalation Cancer	Inhalation Noncancer (Chronic)	Inhalation Noncancer (Acute)
Acetaldehyde			✔	✔	✔
Acrolein				✔	✔
Ammonia				✔	✔
Benzene			✔	✔	✔
1,3-Butadiene			✔	✔	
Ethylbenzene			✔	✔	
Formaldehyde			✔	✔	✔
Napthalene		✔	✔	✔	
Polycyclic Aromatic Hydrocarbons (PAHs, as BaP)	✔		✔		
Propylene Oxide			✔	✔	✔
Toluene				✔	✔
Xylene				✔	✔

Source: OEHHA / ARB 2016b

Exposure Assessment

Public Health Table 4 shows the exposure routes of TACs and how they would contribute to the total risk obtained from the health risk analysis. The applicable exposure pathways for the toxic emissions include inhalation, home grown produce, dermal (through the skin) absorption, soil ingestion, and mother’s milk. This method of assessing health effects is consistent with OEHHA’s Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA 2015) referred to earlier.

The next step in the assessment process is to estimate the project's incremental concentrations using a screening air dispersion model and assuming conditions that would result in maximum impacts. The project owner used the EPA-recommended air dispersion model, AERMOD, along with 5 years (2010–2014) of compatible meteorological data from the John Wayne Airport meteorological station (HBEP 2015a, Section 5.1.5.2).

Dose-Response Assessment

Public Health Table 5 lists the toxicity values used to quantify the cancer and noncancer health risks from the project's combustion-related pollutants. It was modified from Table 5.9-2 and Table 5.9-3 of the PTA Revised Air Quality and Public Health Assessment Sections (HBEP 2015A, Section 5.1.5.2], excluding oral cancer potency factor and chronic oral REL. The listed toxicity values include RELs and the cancer potency factors published in the OEHHA's Guidelines (OEHHA 2015) and OEHHA/ARB Consolidation Table of OEHHA/ARB Approved Risk Assessment Health Values (ARB 2016b). RELs are used to calculate short-term and long-term noncancer health effects, while the cancer potency factors are used to calculate the lifetime risk of developing cancer.

Public Health Table 5
Toxicity Values Used to Characterize Health Risks

Toxic Air Contaminant	Inhalation Cancer Potency Factor $(mg/kg\text{-}d)^{-1}$	Chronic Inhalation REL ($\mu g/m^3$)	Acute Inhalation REL ($\mu g/m^3$)
Acetaldehyde	0.010	140	470 (1-hr) 300 (8-hr)
Acrolein	—	0.35	2.5 (1-hr) 0.7 (8-hr)
Ammonia	—	200	3,200
Benzene	0.10	60	1,300
1,3-Butadiene	0.60	20	—
Ethylbenzene	0.0087	2,000	—
Formaldehyde	0.021	9	55 (1-hr) 9 (8-hr)
Napthalene	0.12	9.0	—
Polycyclic Aromatic Hydrocarbons (PAHs, as BaP)	3.9	—	—
Propylene Oxide	0.013	3	3100
Toluene	—	300	37,000
Xylene	—	700	22,000

Sources: OEHHA/ARB 2016b

Characterization of Risks from TACs

As described above, the last step in a HRA is to integrate the health effects and public exposure information, provide quantitative estimates of health risks resulting from project emissions, and then characterize potential health risks by comparing worst-case exposure to safe standards based on known health effects.

The project owner's HRA was prepared using the ARB's HARP2. Emissions of non-criteria pollutants from the project were analyzed using emission factors, as noted previously, obtained mainly from the SCAQMD. Air dispersion modeling combined the emissions with site-specific terrain and meteorological conditions to analyze the worst-case short-term and long-term concentrations in air for use in the HRA. Ambient concentrations were used in conjunction with cancer unit risk factors and RELs to estimate the cancer and noncancer risks from operations. In the following sub-sections, staff reviews and summarizes the work of the project owner, and evaluates the adequacy of the project owner's analysis by conducting an independent HRA.

Staff evaluated the project owner's analysis, and the results are shown below in **Public Health Table 6**. Staff also included the results of the 2014 FSA for the Licensed HBEP for comparison (CEC 2014d). The analysis was conducted for the general population, sensitive receptors, nearby residences and the project's work force. The sensitive receptors, as previously noted, are subgroups that would be at greater risk from exposure to emitted pollutants, and include the very young, the elderly, and those with existing illnesses.

On March 6, 2015, OEHHA approved a revision to the Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments (OEHHA 2015). OEHHA developed age sensitivity factors to take into account the increased sensitivity to carcinogens during early-in-life exposure (OEHHA 2015, Table 8.3). This new methodology is used to reflect the fact that exposure varies among different age groups and exposure occurring in early life has a higher weighting factor.

Health risks potentially associated with ambient concentrations of carcinogenic pollutants were calculated in terms of excess lifetime cancer risks. The total cancer risk at any specific location is found by summing the contributions from the individual carcinogens. Health risks from non-cancer health effects were calculated in terms of hazard index as a ratio of ambient concentration of TACs to RELs for that pollutant.

The following is a summary of the most important elements of the health risk assessment for the Amended HBEP (HBEP 2016n, Section 5.9.3.2):

- The analysis was conducted using the latest version of ARB/OEHHA HARP2[3], which incorporates methodology presented in OEHHA's 2015 Guidance;
- Emissions are based upon concurrent operation of all four natural-gas-fired turbines and one auxiliary boiler. The existing fire pumps are already permitted by the SCAQMD and are considered part of the existing background conditions, so they were not included in the public health analysis for HBEP;
- Mandatory minimum pathways and homegrown pathways were selected to evaluate cancer risk and chronic hazard index at the PMI, MEIR, and sensitive receptor;
- Worker pathways (inhalation, dermal, and soil) were selected to evaluate cancer risk and chronic hazard index at the MEIW;

[3] HARP2 can be downloaded from ARB's HARP website. http://www.arb.ca.gov/toxics/harp/harp.htm

- The Risk Management Policy Derived method was used to calculate cancer risk at the PMI, MEIR, and sensitive receptor, consistent with SCAQMD guidance (SCAQMD, 2015); the OEHHA-Derived method was used for all remaining scenarios.

Cancer Risk at the Point of Maximum Impact

The most significant result of a HRA is the numerical cancer risk for the maximally exposed individual (MEI) which is the individual located at the PMI and risks to the MEIR. As previously noted, human health risks associated with emissions from the proposed project are unlikely to be higher at any other location than at the PMI. Therefore, if there is no significant impact associated with concentrations at the PMI location, it can be reasonably assumed that there would not be significant impacts in any other location in the project area. The cancer risk to the MEI at the PMI is referred to as the MICR. However, the PMI (and thus the MICR) is not necessarily associated with actual exposure because in many cases, the PMI is in an uninhabited area. Therefore, the MICR is generally higher than the maximum residential cancer risk. MICR is based on 24 hours per day, 365 days per year, 30 year lifetime exposure.

As shown below in **Public Health Table 6**, total worst-case individual cancer risk for the Amended HBEP was calculated by staff to be 4.26 in one million at the PMI. The PMI is approximately 0.15 miles northeast of the HBEP facility boundary. As **Public Health Table 6** shows, the cancer risk value at PMI is below the significance level, 10 in one million, indicating that no significant adverse cancer risk is expected.

Chronic and Acute Hazard Index (HI)

The screening HRA for the project included emissions from all sources and resulted in a maximum chronic Hazard Index (HI) of 0.011 and a maximum acute HI of 0.056 (HBEP 2016n, Table 5.9-4). As **Public Health Table 6** shows, both acute and chronic hazard indices are less than 1.0, indicating that no short- or long-term adverse health effects are expected.

Project-Related Impacts at Area Residences

Staff's specific interest in the risk to the maximally exposed individual in a residential setting is based on the MEIR (MEIR is used for this purpose because this risk most closely represents the maximum project-related lifetime cancer risk). Residential risk is presently assumed by the regulatory agencies to result from an exposure lasting 24 hours per day, 365 days per year, over a 30- year lifetime. Residential risks are presented in terms of MEIR and health hazard index (HHI) at residential receptors in **Public Health Table 6**. The cancer risk for the MEIR[4] is 2.68, which is below the significance level. The maximum resident chronic HI and acute HI are 0.0068 and 0.019, respectively (HBEP 2016n, Table 5.9-4). They are both less than 1.0, indicating that no short- or long-term adverse health effects are expected at these residences.

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[4] The AFC states the nearest resident is approximately 250 feet west-northwest of the facility along Newland Street (HBEP 2012a, Section 5.9.1.1); however, the MEIR is not located at this position, but is located approximately 0.4 mile northeast of the HBEP boundary.

Risk to Workers

The cancer risk to potentially exposed workers was presented by the project owner in terms of risk to the maximally exposed individual worker or MEIW at PMI and is also summarized in **Public Health Table 6**. The project owner's assessment for potential workplace risks uses a shorter duration exposure rather than the 70-year exposure used for residential risks. Workplace risk is presently calculated by regulatory agencies using exposures of 8 hours per day, 245 days per year, over a 25- year period. As shown in **Public Health Table 6**, the cancer risk for workers at MEIW (i.e. 0.15 in 1 million) is below the significance level (HBEP 2016n, Table 5.9-4).

Risk to Sensitive Receptors

The highest cancer risk at a sensitive receptor is 1.49 in one million[5], the highest chronic HI is 0.0038 and the acute HI is 0.013. (HBEP 2016n, Table 5.9-4). All risks are below significance levels.

In **Public Health Table 6**, it is notable that the cancer and noncancerous risks from Amended HBEP operation would be below their respective significance levels. This means that no health impacts would occur within all segments of the surrounding population. Therefore, staff concludes there is no need for conditions of certification to protect public health.

Title 40 CFR Part 63

The regulation applied to gas turbines located at major sources of HAP emissions is 40CFR Part 63 Subpart YYYY. A major source is defined as a facility with emissions of 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit.

The potential National Emissions Standards for Hazardous Air Pollutants (NESHAP) applicable to the Amended HBEP is Subpart YYYY, which sets a formaldehyde emission limit or an operational limit of 91 part(s) per billion by volume (ppbv) for turbines. Subpart YYYY sets emissions limits and requires notifications, source testing, monitoring, and recordkeeping for gas turbines. However, EPA proposed to delist natural gas-fired turbines from the NESHAP's on August 14, 2004. Therefore, in accordance with §63.6095(d) of this subpart, natural gas-fired turbines are exempt from all requirements other than the initial notification to the Administrator (SCAQMD 2014a and SCAQMD 2014c).

[5] This sensitive receptor is located approximately 0.6 mile northeast of HBEP boundary, not the nearest sensitive receptor.

Public Health Table 6
Cancer Risk and Chronic Hazard from HBEP Operations

Receptor Location	Cancer Risk (per million)		Chronic HI[f]		Acute HI[f]	
	2014 FSA for Licensed HBEP	2015 PTA for HBEP	2014 FSA for Licensed HBEP	2015 PTA for HBEP	2014 FSA for Licensed HBEP	2015 PTA for HBEP
PMI[a]	2.54[d]		0.00778	0.011	0.0781	0.056
	4.32[e]	4.26				
Residence MEIR[b]	2.2	2.68	0.00691	0.0068	0.0502	0.019
Worker MEIW[c]	0.446	0.15	0.00778	0.011	0.0781	0.056
Highest Cancer Risk at a Sensitive Receptor	1.65	1.49	0.00519	0.0038	0.0183	0.013
Significance level	10		1		1	

Source: HBEP 2016n, Table 5.9-4
[a] PMI = Point of Maximum Impact
[b] MEIR = MEI of residential receptors. Location of the residence of the highest risk with a 30-year residential scenario.
[c] MEIW = MEI for offsite workers. Occupational exposure patterns assuming standard work schedule, i.e. exposure of 8 hours/day, 5 days/week, 49 weeks/year for 25 years.
[d] Applicant's calculated value using previous OEHHA methodology.
[e] Cancer risk calculated by using the Age Sensitivity Factors recommended by OEHHA (OEHHA 2012).
[f] HI = Hazard Index

CUMULATIVE IMPACTS AND MITIGATION

A project would result in a significant adverse cumulative impact if its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (California Code of Regulations, Title 14, section 15130). As for cumulative impacts for cumulative hazards and health risks, if the implementation of the amended project, as well as the past, present, and probable future projects, would not cumulatively contribute to regional hazards, then it could be considered a less than cumulatively considerable impact.

The geographic scope of analysis for cumulative effects to public health is a six-mile buffer zone around the project site. This is the same six-mile buffer zone for localized significant cumulative air quality impacts described and evaluated in the Air Quality section. While MATES II and MATES III studies were discussed, cumulative impacts of the amended project along with other projects within a 6-mile radius were not quantitatively evaluated in the PTA (HBEP 2016n, section 5.9.4).

The maximum cancer risk and non-cancer hazard index (both acute and chronic) for operations emissions from the Amended HBEP estimated independently by the project owner, staff, and the SCAQMD (SCAQMD 2016b)are all below the level of significance. While air quality cumulative impacts could occur with sources within a 6-mile radius, cumulative public health impacts are usually not significant unless the emitting sources are extremely close to each other, within a few blocks, not miles. Since no cumulative projects are within a few blocks of the HBEP, staff concludes that the Amended HBEP project, even when combined with these projects, would not contribute to cumulative impacts in the area of public health.

Moreover, as previously noted, the maximum impact location would be the spot where pollutant concentrations for the amended project would theoretically be highest. Even at this hypothetical location, staff does not expect any significant change in lifetime risk to any person, given the calculated incremental cancer risk of 4.26 in one million, which staff regards as not contributing significantly to the previously noted county-wide population-weighted risks of MATES VI, 315 per million for Orange County and 367 per million for SCAB. Modeled facility-related risks are much lower for more distant locations. Given the previously noted conservatism in the calculation method used, the actual risks would likely be much smaller. Therefore, staff does not consider the incremental risk estimate from Amended HBEP’s operation as suggesting a potentially significant contribution to the area’s overall or cumulative cancer risk that includes the respective risks from the background pollutants from all existing area sources.

COMPLIANCE WITH LORS

Staff has conducted a HRA for the Amended HBEP and found no potentially significant adverse impacts for any receptors, including sensitive receptors. In arriving at this conclusion, staff notes that its analysis complies with all directives and guidelines from the Cal/EPA Office of Environmental Health Hazard Assessment and the California Air Resources Board. Staff’s assessment is biased towards protection of public health and takes into account the most sensitive individuals in the population. Using extremely conservative (health-protective) exposure and toxicity assumptions, staff’s analysis demonstrates that members of the public potentially exposed to toxic air contaminant emissions from this project, including sensitive receptors such as the elderly, infants, and people with pre-existing medical conditions, would not experience any acute or chronic significant health risk or any significant cancer risk as a result of that exposure.

Staff incorporated every conservative assumption called for by state and federal agencies responsible for establishing methods for analyzing public health impacts. The results of that analysis indicate that there would be no direct or cumulatively significant public health impact on any population in the area. Therefore staff concludes that construction and operation of the HBEP and demolition of the HBGS would comply with all applicable LORS regarding long-term and short-term project impacts in the area of public health.

Additionally, staff reviewed **Socioeconomics Figure 1**, which shows that the environmental justice population (see the **SOCIOECONOMICS** and **EXECUTIVE SUMMARY** sections of this PSA for further discussion of environmental justice) is not greater than fifty percent within a six-mile buffer of the Amended HBEP site. Because no members of the public potentially exposed to toxic air contaminant emissions from this project would experience acute or chronic significant health risk or cancer risk, there would not be a public health impact resulting from construction and operation of the amended project to an environmental justice population or any other group of people.

CONCLUSIONS AND RECOMMENDATIONS

Staff has analyzed the potential public health risks associated with construction and operation of the Amended HBEP using a conservative methodology that accounts for impacts to the most sensitive individuals in a given population. Staff concludes that there would be no significant health impacts from the project's toxic air emissions. According to the results of the HRA, both construction/demolition and operating emissions from the HBEP would not contribute significantly or cumulatively to morbidity or mortality in any age or ethnic group residing in the project area.

PROPOSED CONDITIONS OF CERTIFICATION

No public health conditions of certification are proposed for Amended HBEP.

REFERENCES

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

CEC 2014d - Final Staff Assessment (TN 202405). Submitted to CEC/ Docket Unit June 2, 2014.

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HBEP 2016n - AES Southland Development, LLC/Stephen O'Kane (TN 210969). Petition to Amend (12-AFC-02C) Revised Air Quality and Public Health Assessment, dated April 6, 2016. Submitted to John Heiser/CEC/Docket Unit on April 6, 2016

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HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
SOCIOECONOMICS

Lisa Worrall

SUMMARY OF CONCLUSIONS

Energy Commission staff concludes that the proposed amendment to the licensed Huntington Beach Energy Project (HBEP) would not cause significant direct, indirect, or cumulative adverse socioeconomic impacts on the project area’s housing, schools, law enforcement services, and parks. Staff also concludes that the amended HBEP would not induce a substantial population growth or displacement of population, or induce substantial increases in demand for housing, parks, or law enforcement services. Conditions of certification **SOCIO-1** and **SOCIO-2** from the 2014 Final Commission Decision (Decision) would ensure project compliance with state and local laws, ordinances, regulations, and standards (LORS).

Staff also concludes that the findings of fact and the conclusions of law from the Decision would still apply to the amended HBEP. Therefore, in accordance with California Environmental Quality Act (CEQA) Guidelines Section 15162, staff concludes that no supplementation to the Decision is necessary for Socioeconomics. The Committee may rely upon the environmental analysis and conclusions of the Decision for Socioeconomics and does not need to re-analyze them.

INTRODUCTION

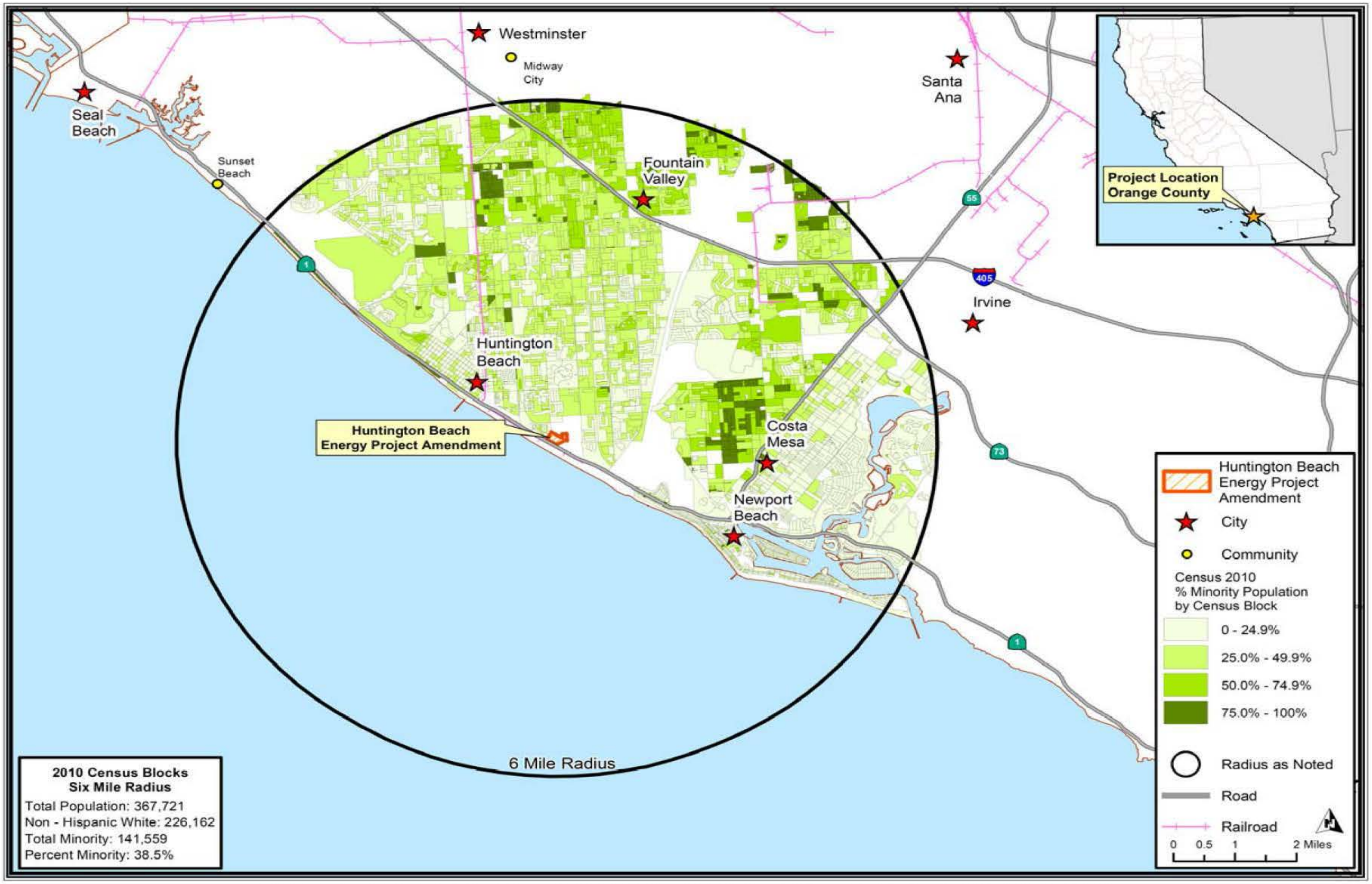
Staff reviewed the Decision and the changes to the licensed HBEP relevant to Socioeconomics. The HBEP amendment would increase the construction workforce from a peak of 236 to a peak of 306 workers (HBEP 2015i, pg. 33 and Appendix 5.10A-R1). The average number of construction workers would be reduced from 192 workers to 127 workers (CEC 2014d, pg.4.8-9). The operations workforce would be reduced from 33 to 23 members. The HBEP amendment would take 67 months overall to complete, compared with 56 months estimated for the licensed HBEP.

MINORITY AND BELOW-POVERTY-LEVEL POPULATIONS

The 2010 U.S. Census data staff used to identify minority-based environmental justice populations for **Socioeconomics Figure 1** used in the 2014 Commission Decision is still current. As identified in the Commission Decision, there is no minority environmental justice population present in the project’s six-mile radius. To determine whether a poverty-based environmental justice population is present, staff used the most currently available poverty data from the U.S. Census American Community Survey (ACS), presented in **Socioeconomics Table 1**, below.

SOCIOECONOMICS - FIGURE 1

Huntington Beach Energy Project Amendment - Census 2010 Minority Population by Census Block - Six Mile Radius



CALIFORNIA ENERGY COMMISSION, SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Multinet, Census 2010 - PL94-171, Open Street Map City Data March 2013.

Based on 2010-2014 ACS census data, 10.02 percent of people within the six-mile radius of the HBEP are living below the poverty level. Since this is less than the 12.80 percent of people living below the poverty level in Orange County, the population within a six-mile radius of HBEP does not constitute an environmental justice population as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*.

Socioeconomics Table 1
Poverty Data within the Project Area

Area	Total			Income in the past 12 months below poverty level			Percent below poverty level		
	Estimate[1]	MOE[2]	CV[3] (%)	Estimate	MOE	CV (%)	Estimate	MOE	CV (%)
Cities Used to Determine Poverty Status- Total	447,742	439	0.06	44,862	±2,530	3.43	10.02	±0.57	3.46
Costa Mesa	110,636	±182	0.10	16,719	±1,481	5.38	15.10	±1.3	5.23
Fountain Valley	56,185	±179	0.19	4,017	±724	10.96	7.10	±1.3	11.13
Huntington Beach	194,680	±305	0.10	17,895	±1,672	5.68	9.20	±0.9	5.95
Newport Beach	86,241	±186	0.13	6,231	±941	9.18	7.20	±1.1	9.29
Reference Geography									
Orange County	3,049,290	±2,022	0.04	391,705	±7,700	1.19	12.80	±0.3	1.24

Note: [1] Population for whom poverty status is determined. [2] MOE Margin of Error - a range of how well the sample represents the actual population. [3] CV Coefficient of Variation - a measure of the reliability of data. **Sources:** US Census 2015 and UW-Extension 2011.

SUMMARY OF THE DECISION

Based on the evidence presented in the original proceeding, the Energy Commission made the following conclusions of law:

1. The HBEP is compliant with all laws, ordinances, regulations, and standards.
2. The HBEP does not create direct or indirect significant adverse impacts on population, housing, schools, parks and recreation, or law enforcement.
3. The HBEP does not create cumulative impacts on population, housing, schools, parks and recreation, or law enforcement.
4. There is not an environmental justice population, based on either the presence of minority or low-income populations, within six-miles of the HBEP project site.
5. Payment of school fees to the Huntington Beach Union High School District as required by Education Code Section 17620 constitutes sufficient analysis and mitigation of any impacts of the HBEP on school facilities.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS) COMPLIANCE

No LORS applicable to the project have changed since the Decision was published in November 2014. Additionally, the proposed amendment would not trigger new LORS that may not have been applicable to the original project.

ENVIRONMENTAL IMPACT ANALYSIS

In accordance with the CEQA Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Decision is necessary for Socioeconomics. The Committee may rely upon the environmental analysis and conclusions of the Decision concerning Socioeconomics 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 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 that would require major revisions of the Socioeconomics analysis in the Decision.
- The circumstances under which the HBEP amendment would be undertaken would not require major revisions of the Socioeconomics analysis in the Decision.

Staff's conclusion is supported by the following key factual information:

- The change in construction workforce numbers and duration are minimal and workforce-related impacts would remain less than significant.
- The operations staff is reduced.
- The large labor pool in Orange, Los Angeles, Riverside, and San Bernardino counties is more than sufficient to accommodate the labor needs of the HBEP amendment.

CUMULATIVE IMPACTS AND MITIGATION

A project may result in significant adverse cumulative impacts when its effects are cumulatively considerable. Cumulatively considerable means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects [Cal. Code Regs., tit.14, § 15065 (a)(3)].

In a socioeconomic analysis, cumulative impacts could occur when more than one project in the same area has an overlapping construction schedule, thus creating a demand for workers that cannot be met locally, or when a project's demand for public services does not match a local jurisdiction's ability to provide such services. An influx of non-local workers and their dependents can strain housing, schools, parks and recreation, and law enforcement services.

Staff has updated the Master Cumulative Project List since the licensing of the HBEP. Because of the large labor supply in Orange County and the mobility of the labor supply, staff included projects in Orange County and the cities within the county that would likely employ a similar workforce to the HBEP amendment.

Staff reviewed this updated list for projects that would likely have overlapping construction schedules with the HBEP amendment. The projects listed below in **Socioeconomics Table 2** represent the updated cumulative setting for socioeconomic resources.

Socioeconomics Table 2
HBEP Amendment Socioeconomics Cumulative Project List

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
1	Huntington Beach Generating Station Demolition (Demolition of Units 3 & 4)	Demo/removal of Units 3 & 4 from the existing Huntington Beach Generating Station.	Huntington Beach Generating Station, Huntington Beach	0.05	Demo estimated Q2 2020 to Q1 2022 (27 mo.)
2	Poseidon Desalination Plant	A 50-million-gallon-per-day, seawater desalination facility located on 11-acre portion of the existing Huntington Beach Generating Station (HBGS) facility. Project would use existing HBGS seawater intake and outfall pipelines for operations.	21730 Newland St, Huntington Beach	0.22	Planning
3	Magnolia Oil Storage Tank and Transfer Facility Demolition and Removal	Demolition and removal of three empty above ground crude oil storage tanks and ancillary site improvements.	21845 Magnolia St, Huntington Beach	0.35	In Progress
4	Newland St Residential (Pacific Shores)	Develop and subdivide former industrial site to residential with 204 multi-family residential units and two-acre public park.	21471 Newland St, Huntington Beach	0.40	Completed
5	Remedial Action Plan for Ascon Landfill Site	Remedial Action Plan includes partial removal of waste materials and construction of protective cap over remaining waste materials.	Magnolia St and Hamilton Ave, Huntington Beach	0.43	Plan Check
6	Hilton Waterfront Beach Resort Expansion	Nine-story tower with 156 new guestrooms, appurtenant facilities, 261 parking spaces, a loading dock and other back-of-house facilities.	21100 Pacific Coast Hwy, Huntington Beach	1.02	Plan Check
8	P2-92 Sludge Dewatering and Odor Control	Build new sludge and odor control facilities at existing Plant 2.	Santa Ana River Channel, Huntington Beach	1.17	Construction scheduled Spring 2016
9	Pacific City	516 condominiums; 8 story-250 room hotel, spa and health club; and 191,100 sq. ft. visitor-serving commercial with retail, office, restaurant, cultural, and entertainment	21002 Pacific Coast Hwy, Huntington Beach	1.26	Under Construction
10	Pierside Pavilion Expansion	Proposes to construct a connecting four-story, mixed-use, visitor-serving/office building and storefront extension.	300 Pacific Coast Hwy, Huntington Beach	1.51	Plan Check

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
12	Beach Walk	173 multi-family apartment units within a 4-story building, a 5-level parking structure, public and private open space areas.	19891 & 19895 Beach Blvd, Huntington Beach	2.10	Completed
13	LeBard Park and Residential Project	9.7-acre surplus school site for public recreation and single-family residential uses.	20461 Craimer Ln, Huntington Beach	2.16	Approved
14	Truewind- Former Wardlow School Site	49 detached single-family residential units on an 8.35-acre site.	9191 Pioneer Dr, Huntington Beach	2.16	Under Construction
15	Brookhurst Street and Adams Avenue IIP	Widening of the Brookhurst St/Adams Ave intersection in all directions.	Brookhurst St and Adams Ave, Huntington Beach	2.38	Draft Environmental Impact Report (DEIR)
16	Lighthouse Project	89-unit (49 residential units, 40 live/work units), three-story mixed-use development. 332 space parking garage, 2 aces of common open space.	1620-1644 Whittier Ave, Costa Mesa	2.42	Initial Study (IS)/Mitigated Negative Declaration (MND)
17	Ebb Tide Residential Project	Demolition of 73 mobile home spaces, three fixed structures and related surface improvements and the development of 81 single-family detached condominium units.	Placentia Ave and 16th St, Newport Beach	2.96	MND
18	Fairwind- Former Lamb School Site	80 detached single-family residential units on a 11.65-acre site	10251 Yorktown Ave, Huntington Beach	2.96	Unknown
19	Westside Gateway Project	Seeking approval to redevelop a 9-acre project site with a mix of 177 dwelling units (residential lofts and live/work). Redevelopment includes demolition of all existing buildings and parking areas.	671 W. 17th St, Costa mesa	3.20	Unknown
20	Beach and Ellis - Elan Mixed Use	274 units (26 studio, 123 one-bedroom, 6 live-work, 119 two-bedroom units of which 27 are affordable units) also includes: 8,500 sq. ft. commercial, 17,540 sq. ft. public open space and 31,006 sq. ft. residential private open space.	18502, 18508-18552 Beach Blvd, Huntington Beach	3.37	Unknown
21	Newport Beach City Hall Reuse Project- Now called the "Lido House Hotel"	Four story, 130-room hotel set on a 4.25-acre site that formerly housed the Newport Beach City Hall.	3300 Newport Blvd, Newport Beach	3.45	IS/ND
22	2277 Harbor Boulevard Project	Proposal involves demolishing existing 236-room motel and the construction of a four-story, 224-unit luxury apartment project.	2277 Harbor Boulevard, Costa Mesa	3.50	IS/MND

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
24	Oceana Apartments	Four story apartment building with 78 affordable housing units for income levels at 30 to 60 percent of Orange County median income on 2-acre site.	18151 Beach Blvd, Huntington Beach	3.75	Under Construction
26	Huntington Beach Senior Center	One-story senior center on an undeveloped portion of Central Park. Approximately 227 parking spaces will be provided for visitors and city vehicles.	Central Park (5-acre area; SW of the intersection of Goldenwest St and Talbert Ave)	4.14	Under Construction
29	Well #6 Colored Water Treatment Plant	Construct WTP within the next two years.	Harbor Blvd at Gisler Ave, Costa Mesa	4.48	Unknown
30	Fountain Valley Civic Center Specific Plan	Build Ayres Hotel, 88 residential units (27 single-family, 61 townhomes), and 2,300 sq. ft. of retail space on 8.62-acres.	Brookhurst St and Slater Ave, Fountain Valley	4.64	Unknown
32	Back Bay Landing Project	New reservoir foundation, install underground pipelines	East Coast Hwy at Bayside Dr, Newport Beach	4.76	Under review with Coastal Commission
35	Beach Blvd and Warner Ave Intersection Improvement Project	Construct westbound right turn lane on Warner Ave at intersection and associated improvements including new 5 ft. wide, 15 ft. long sidewalk along west side of A Lane.	Intersection of Beach Blvd and Warner Ave, on the north side of Warner Ave from Beach Blvd to the alley between A Lane and B Lane, including portions of the adjacent commercial properties to the north at 16990 Beach Blvd, 8021 Warner Ave, and 8071 Warner Ave.	4.92	Adopted

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
36	Beach Edinger Corridors Specific Plan	Removal Action Workplan includes excavation of Volatile Organic Compound and lead-impacted soil areas within and around site building. Approximately 1,800 tons of soil to be generated from excavation of 3,000 sq. ft. area to 12 ft. below the ground surface. Excavation then proceeds approximately 4 ft. below water table. Groundwater to be pumped up to 24 hrs. to remove estimated 10,000 gallons of groundwater. Soil transported off-site to permitted facility. Soil confirmation sampling of excavation flood and sidewalls to verify soil exceeding cleanup objectives been satisfactorily removed. Following completion of the remedial excavation and confirmation sampling, excavation backfilled with either native material taken from other areas of the property or from an approved borrow site. Excavated area returned to grade and suitable standards of completion. Installation of sub-slab methane-mitigation barrier and venting system to address naturally occurring methane in site area. Sub-slab system will be installed beneath the new multi-family residential building that will occupy the site and surrounding properties.	Edinger Ave to Atlanta Ave, Huntington Beach	5.16	Planning
39	Parkside Estates	111 single-family residences; 23-acres preserved, restored and enhanced open space; 1.6-acre neighborhood park; public trails; and water quality treatment system.	W side Graham St, S of Warner Ave, along E Garden Grove Wintersburg Flood Channel 17221 (S of Greenleaf Ln), Huntington Beach	5.67	Planning
41	Brightwater	347 single-family units and over 37-acres habitat restoration and trails.	Warner Ave and Los Patos Ave, Huntington Beach	5.77	Under Construction
44	Monogram Apartments (Formerly Pedigo)	Four-story apartment building with 510 dwelling units and six-level, 862-space parking structure.	7262,7266,7280 Edinger Ave and 16001, 17091 Gothard St, Huntington Beach	5.96	Plan Check

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
45	The Boardwalk (Murdy Commons)	487 dwelling units and 14,500 sq. ft. of commercial area on a 12.5-acre site with 1/2 acre public park.	7441 Edinger Ave-Northeast corner of Edinger Ave and Gothard St (Former Levitz Furniture store site)	5.97	Under Construction. First two phases have opened for occupancy.
47	Airport Circle Residential Project	45-unit condominium subdivision with open space on 2.5-acre site. Site layout: 8 detached three-story buildings with 4 to 8 attached dwelling units.	16911 Airport Cir. Huntington Beach	6.04	Plan Check
48	The Village at Bella Terra	Costco Wholesale, with gasoline service station and mixed-use retail and residential project.467 multi-family residential units within four-story building.	7777 Edinger Ave, Huntington Beach	6.06	Completed
49	San Diego Freeway I-405 Improvement Project	One general-purpose lane in each direction on I-405 from Euclid St to the I-605 interchange, add tolled express lane in each direction of I-405 from SR-73 to SR-22 East.	I-405 between SR-73 & I-605, Costa Mesa, Seal Beach	6.06	Unknown
50	Huntington Beach Lofts	Five-story, 385-luxury residential units located above 10,000 sq. ft. of street level retail and commercial uses.	7302-7400 Center Ave, Huntington Beach	6.16	Under Construction
52	Wyndham Boutique Hotel/High-Rise Residential Project	Demolition of Wyndham Hotel parking garage and construction of a 100-unit condominium tower adjacent to a new 6.5-level parking garage with 1 subterranean level and 5.5 levels above ground.	3350 Ave of the Arts, Costa Mesa	6.53	Approved
54	OC-44 Pipeline Rehabilitation Project	Sip-line existing 42-inch pipeline with new 30-inch Ductile Iron Pipe. To accommodate these improvements, a pipe jacking operation would be conducted, requiring three access pits.	University Dr and La Vida, Newport Beach	6.61	Approved-Construction 2018-2020
55	Civic Center and Park Project	Construction of park, city hall building, and 450 parking spaces.	Avocado Ave and McArthur Blvd, Newport Beach	6.62	Unknown
56	Uptown Newport Village Specific Plan Project	Mixed-use project with 1,244 residential units, 11,500 sq. ft. retail, and a 2-acre park.	Jamboree Rd and Fairchild Rd, Newport Beach	6.92	Approved
58	Rofael Marina and Caretaker Facility	Construct marina on 6,179 sq. ft. property.	16926 Park Ave, Huntington Beach	7.12	In Progress. Requires Coastal Development Permit and a Conditional Use Permit.

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
59	Campus and Jamboree	1,600 residential units (5 to 6-story apartments), 17,000 sq. ft. plus primary retail in Irvine Technology Center, and up to 23,000 sq. ft. accessory retail and/or residential-serving amenities, 1-acre public park, and two 0.5-acre public plazas.	NW corner of Campus and Jamboree, Irvine	7.37	Phase 1 Under Construction (9/26/2015)
60	Mater Dei High School Parking Structure	Three-level parking structure	1202 W Edinger Ave, Santa Ana	7.80	Proposed, 3-5 years 2018 at earliest
62	Warner Avenue Widening	Widening to six lanes.	Warner Ave, Santa Ana	8.48	Approved. Construction in four phases. Phase 1 Jan. 2016 to Jan 2017.
63	2801 Kelvin	384-unit apartments.	2801 Kelvin Ave, Irvine	8.70	Under Construction. 18-month construction period
65	Vista Verde	Build 55-unit project, which is proposing to add 3 additional units to the project	5144 Michelson Dr, Irvine	10.00	Unknown
67	I-5 Central County Improvement Project	Add second carpool lane in each direction on I-5 between the SR-55 and the SR-57.	I-5 between SR-55 and SR-57, cities of Santa Ana, Tustin and Orange.	10.39	Approved. Construction Jan. 2016 to Jan 2017.
68	I-5, SR-73 to El Toro Road	Widen I-5 to accommodate general-purpose lanes in each direction. Reestablish existing auxiliary lanes. Extend second carpool lane from El Toro Rd. to Alicia Parkway in both directions and modify ramps as needed. Reconstruct Avery Parkway and La Paz Rd. interchanges. 2018 to 2022	I-5 between SR-73 to El Toro Rd, cities of Laguna Hills, Laguna Woods, Laguna Niguel, Mission Viejo, Lake Forest, and San Juan Capistrano.	10.67	Proposed
69	Alamitos Energy Center	Two natural gas turbine power blocks. Power Block 1:natural-gas-fired combustion turbine generators in combined-cycle configuration, two unfired heat recovery steam generators, one steam turbine generator, air-cooled condenser, auxiliary boiler, related ancillary equipment. Power Block 2: four simple-cycle combustion turbine generators with fin-fan coolers and ancillary facilities. 21-acre site within larger 71.1-acre Alamitos Generation Station site.	690 N Studebaker Rd, Long Beach	10.74	Proposed
72	Irvine Center Drive and Alton, NWC.	766-unit apartments.	Northwest corner of Irvine Center Dr and Alton Pkwy, Irvine	12.84	Under Construction. Estimated 24-month construction

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
74	Pacifica and Spectrum NWC	573-unit apartments	SW corner of Alton Pkwy and Spectrum, Irvine	13.19	Under Construction. 24-month construction
81	I-5 between Avenida Pico to San Juan Creek Road	Add carpool lane both directions on I-5 between Avenida Pico to San Juan Creek Road. Reconstruct interchange at Avenida Pico. Widen northbound Avenida Pico on-ramp to three lanes. Provide dual left-turn lanes to both northbound and southbound Avenida Pico on-ramps. Add sound walls where needed.	I-5 between Avenida Pico and San Juan Creek Rd, San Clemente, San Juan Capistrano and Dana Point.	21.14	Under Construction 2013 to 2017.

The large labor pool in Orange, Los Angeles, Riverside, and San Bernardino counties is more than sufficient to accommodate the labor needs of the HBEP amendment and the cumulative projects in **Socioeconomics Table 2**. Therefore, the HBEP amendment in combination with the other projects in the cumulative study area would not have significant cumulative impacts from population influx (construction and operations workers) on housing supply, law enforcement, and parks and recreation.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that proposed amendment would have no new socioeconomic impacts and the mitigation for the original project would still be applicable and would not require any changes. The following findings of fact from the Decision would still apply to the HBEP amendment:

1. The amended HBEP would not directly displace existing housing or people.

2. The amended project's construction and operation workforces would not directly or indirectly induce a substantial population growth in the project area.

3. The amended project's construction and operation workforce would not have a significant adverse impact on housing within the project area and would not displace any people or housing, or necessitate construction of replacement housing elsewhere.

4. The amended HBEP would not result in substantial adverse physical impacts associated with the provision of new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives with respect to law enforcement service.

5. The amended HBEP would not result in substantial adverse physical impacts associated with the provision of new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives with respect to education.

6. The amended HBEP would not result in substantial adverse physical impacts associated with the provision of new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives with respect to parks.

7. The amended HBEP would not increase the use of existing neighborhood and regional parks or recreational facilities to the extent that substantial physical deterioration of the facility would occur or be accelerated and new parks are not proposed by or needed because of the project.

8. The workforce available in the area of the HBEP site is sufficient for the amended project plus other future planned projects.

9. The minority population within six miles of the HBEP site is not meaningfully greater than the minority populations in the comparison geographies.

10. The below-poverty-level population within six miles of the HBEP site is not meaningfully greater than the below-poverty-level population in the comparison geographies.

PROPOSED CONDITIONS OF CERTIFICATION

Existing conditions of certification **SOCIO-1** and **SOCIO-2** would be sufficient to ensure the project remains in compliance with applicable state and local LORS. Therefore, staff does not propose any modifications to the existing conditions of certification.

SOCIO-1 The project owner shall pay the one-time statutory school facility development fees to the Huntington Beach Union High School District as required by Education Code Section 17620.

Verification: At least 30 days prior to the start of project construction, the project owner shall provide to the Compliance Project Manager (CPM) proof of payment to the Huntington Beach Union High School District of the statutory development fee.

SOCIO-2 The project owner shall pay the following one-time Development Impact Fees to the city of Huntington Beach as required by Chapter 17 of the Huntington Beach municipal code:

- Police Facilities Development Impact Fees
- Parkland Acquisition and Park Facilities Development Impact Fees

Verification: At least 90 days prior to the start of commercial operation, the project owner shall confer with the CEC's assigned Chief Building Official (CBO) for HBEP to calculate the applicable one-time development impact fee(s) as set forth in Chapter 17 of the Huntington Beach Municipal Code. At least 30 days prior to commercial operation, the project owner shall provide to the Compliance Project Manager (CPM) proof of payment to the city of Huntington Beach of the required Development Impact Fee(s).

REFERENCES

CEC 2014d - Final Staff Assessment (TN 202405). Submitted to CEC/ Docket Unit June 2, 2014.

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HBEP 2015h - Data Responses, Set 1 (Responses to Data Request 1-74) (TN 206858). Submitted to CEC/Docket Unit on December 7, 2015.

UW-Extension 2011 - University of Wisconsin-Extension American Community Survey Statistical Calculator, March 22, 2011, <http://fyi.uwex.edu/community-data-tools/2011/03/22/american-community-survey-acs-statistical-calculator/>.

US Census 2010 - United States Census Bureau, *P2: HISPANIC OR LATINO, AND NOT HISPANIC OR LATINO BY RACE - Universe: Total population, 2010 Census Redistricting Data (Public Law 94-171) Summary File,* <http://factfinder2.census.gov/faces/nav/jsf/pages/index.xhtml>.

US Census 2015 - United States Census Bureau, *S1701 POVERTY STATUS IN THE PAST 12 MONTHS 2010-2014 American Community Survey 5-Year Estimates*, <http://factfinder2.census.gov/faces/nav/jsf/pages/index.xhtml>.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
SOIL AND WATER RESOURCES
Mike Conway

SUMMARY OF CONCLUSIONS

The changes sought in the Petition to Amend (PTA) the Huntington Beach Energy Project (HBEP) would not result in any substantial modifications to the existing Soil & Water Resources conditions of certification. There are no new significant environmental effects or any substantial increase in the severity of previously identified significant adverse effects that would require major revisions of the 2014 HBEP Commission Decision (Decision). Nor is there new information of substantial importance that could not have been known in the Decision regarding substantially more severe impacts. 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 Decision is necessary for Soil & Water Resources. The Committee may rely on the conclusions of the Decision in analyzing the changes to the project's design, operation, and performance pursuant to Title 20, section 1769. This section augments the existing record to reflect current environmental conditions and policy considerations.

Staff and petitioner suggest a minor revision to the conditions of certification. **Soil & Water Table 1** summarizes the proposed change.

Soil & Water Table 1
Summary of Proposed Modifications to Conditions of Certification

Condition of Certification	Proposed Modification(s) to Condition
SOIL&WATER-6	WATER USE AND REPORTING: Propose to reduce annual water use limit from 134 AFY to 120 AFY.

INTRODUCTION

In this section, Energy Commission staff discusses potential impacts of the proposed HBEP amendment on Soil & Water Resources. The HBEP was originally licensed as the 939-megawatt (MW) project in November 2014.

The proposed amendment seeks to modify each of the two power block turbine configurations. The amended project would consist of a two-on-one combined-cycle gas turbine for power Block 1, with a 644 MW capacity, and two simple-cycle gas turbines for power Block 2, with 200 MW of capacity. The amended HBEP would have a reduced total capacity (844 MW) relative to the licensed project (939 MW). The amended project would require a 1.4-acre increase in total project size, bringing the project up to 30-acres. An increase in temporary project laydown and parking would also be required. Total temporary construction area would be 22-acres.

SUMMARY OF THE DECISION

In this section staff summarizes the 2014 Commission Decision for the HBEP. The 2014 Decision discusses HBEP protection from the theoretical 100-year flood. The Decision acknowledges flooding impacts that could originate inland or from the sea. Also included in the discussion was the influence of tides, waves, and sea-level rise. The Decision concluded that the site is adequately protected from the threats of flooding mentioned. No mitigation was specified for hazards from flooding or sea-level rise.

The 2014 Decision considered alternative water supplies for the project. The Commission found that the use of treated wastewater is both environmentally undesirable and economically unsound. The project’s proposed use of potable water was considered a substantial reduction in the facility’s baseline use and therefore a net benefit.

The 2014 Decision stated that one of the main HBEP benefits was that it would allow the cessation of once-through-cooling at the site. When considered cumulatively with other proposed projects, the HBEP would result in a net cumulative benefit in waste discharges to the Pacific Ocean.

The 2014 Decision found that a Water Supply Assessment (WSA) should be prepared for HBEP. The conclusion was that the project had an adequate and reliable water supply. It was also concluded that HBEP would use significantly less water than the existing Huntington Beach Generation Station while generating more energy. HBEP was said to create a net beneficial impact on local water supplies.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The table below summarizes the LORS that are applicable to HBEP.

Soil & Water Table 2
Summary of Laws, Ordinances, Regulations and Standards (LORS)

Applicable LORS	Description
Federal	
Clean Water Act (33 U.S.C. Section 1257 et seq.)	The Clean Water Act (CWA) (33 USC § 1257 et seq.) requires states to set standards to protect water quality, which includes regulation of storm water and wastewater discharges during construction and operation of a facility. California established its regulations to comply with the CWA under the Porter-Cologne Water Quality Control Act.
State	
California Constitution, Article X, section 2	The California Constitution requires that the water resources of the state be put to beneficial use to the fullest extent possible and states that the waste, unreasonable use or unreasonable method of use of water is prohibited.
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 protected water supplies would 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.

Applicable LORS	Description
The Porter-Cologne Water Quality Control Act of 1967, California Water Code Section 13000 et seq.	Requires the State Water Resources Control Board (SWRCB) and the nine Regional Water Quality Control Boards (RWQCBs) to adopt water quality criteria to protect state waters. Those regulations require that the RWQCBs issue waste discharge requirements (WDRs) specifying conditions for protection of water quality as applicable. Section 13000 also states that the state must be prepared to exercise its full power and jurisdiction to protect the quality of the waters of the state from degradation. Although Water Code 13000 et seq. is applicable in its entirety, the following specific sections are included as examples of applicable sections.
California Water Code Section 13240, 13241, 13242, 13243, & Water Quality Control Plan for the Santa Ana River Basin (Basin Plan)	The Basin Plan establishes water quality objectives that protect the beneficial uses of surface water and groundwater in the Region. The Basin Plan describes implementation measures and other controls designed to ensure compliance with statewide plans and policies, and provides comprehensive water quality planning.
California Water Code Section 13260	This section requires filing, with the appropriate RWQCB, a report of waste discharge that could affect the water quality of the state unless the requirement is waived pursuant to Water Code section 13269.
California Water Code Section 13550	Requires the use of recycled water for industrial purposes when available and when the quality and quantity of the recycled water are suitable for the use, the cost is reasonable, the use is not detrimental to public health, and the use would not impact downstream users or biological resources.
Water Recycling Act of 1991 (Water Code 13575 et. seq.)	The Water Recycling Act states that retail water suppliers, recycled water producers, and wholesalers, should promote the substitution of recycled water for potable and imported water in order to maximize the appropriate cost-effective use of recycled water in California.
Water Conservation Act of 2009 (Water Code 10608 et. seq)	This 2009 legislative package requires a statewide 20% reduction in urban per capita water use by 2020. It requires that urban water retail suppliers determine baseline water use and set reduction targets according to specified requirements, and requires agricultural water suppliers to prepare plans and implement efficient water management practices.
California Code of Regulations, Title 17	Requires prevention measures for backflow prevention and cross connections of potable and non-potable water lines.
California Code of Regulations, Title 20, Division 2, Chapter 3, Article 1	The regulations under Quarterly Fuel and Energy Reports (QFER) require power plant owners to periodically submit specific data to the California Energy Commission, including water supply and water discharge information.
SWRCB Order 2009-0009-DWQ	The SWRCB regulates storm water discharges associated with construction affecting areas greater than or equal to 1 acre to protect state waters. Under Order 2009-0009-DWQ, the SWRCB has issued a National Pollutant Discharge Elimination System (NPDES) General Permit for storm water discharges associated with construction activity. Projects can qualify under this permit if specific criteria are met and an acceptable Storm Water Pollution Prevention Plan (SWPPP) is prepared and implemented after notifying the SWRCB with a Notice of Intent.
SWRCB Order R8-2010-0062, NPDES No. CA0001163	This SWRCB permit regulates all operational water discharges from the Huntington Beach Energy Project site, including once-through cooling water, storm water, and industrial process water.
Santa Ana Regional Water Quality Control Board, Permit Order No. R8-2009-0003, NPDES NO. CAG998001	The Santa Ana Regional Water Quality Control Board issued this order to regulate discharges to surface waters that pose a *de minimus* threat.

Applicable LORS	Description
Santa Ana Regional Water Quality Control Board, Permit Order No. R8-2007-0008, NPDES No. CAG918001	This order provides NPDES coverage for discharges of petroleum contaminated water in the Santa Ana region.
Local	
City of Huntington Beach – Code Chapter 14.36 - Sewer System Service Connections, Fees, Charges, and Deposits	Defines local fees for sewer connections and services.
State Policies and Guidance	
Integrated Energy Policy Report (Public Resources Code, Div. 15, Section 25300 et seq.)	In the 2003 Integrated Energy Policy Report (IEPR), consistent with SWRCB Policy 75-58 and the Warren-Alquist Act, the Energy Commission clearly outlined the state policy with regards to water use by power plants, stating that the Energy Commission would approve the use of fresh water for cooling purposes only where alternative water supply sources and alternative cooling technologies are shown to be “environmentally undesirable” or “economically unsound.”
SWRCB Res. 2009-0011 (Recycled Water Policy)	This policy supports and promotes the use of recycled water as a means to achieve sustainable local water supplies and reduction of greenhouse gases. This policy encourages the beneficial use of recycled water over disposal of recycled water.
SWRCB Res. 75-58	The principal policy of the SWRCB that addresses siting of energy facilities is the Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling, adopted by the Board on June 19, 1976, by Resolution 75-58. This policy states that fresh inland waters should only be used for cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound.
SWRCB Res. 77-1	SWRCB Resolution 77-1 encourages and promotes recycled water use for non-potable purposes and use of recycled water to supplement existing surface and groundwater supplies.
SWRCB Res. 2010-0020	SWRCB’s Resolution No. 2010-0020 and adoption of a Policy for the Use of Coastal and Estuarine Waters for Power Plant Cooling (OTC Plan), requires all coastal power plants that utilize OTC to meet new performance requirements (Best Technology Available [BTA]) through a reduction in intake volume and velocity. The proposed project helps achieve the goals of the OTC Plan through dry-cooling and reduced discharge.

ENVIRONMENTAL IMPACT ANALYSIS

Since the conditions and associated hazards at the proposed site are expected to be similar to those previously analyzed, potential impacts to soil and water resources are essentially the same as documented in the 2014 Commission Decision. Where necessary, staff provides updated information to help the Committee understand the environmental setting.

CONSTRUCTION IMPACTS AND MITIGATION

Land Disturbance

The construction of the amended HBEP would require the use of an additional 1.4 acres for the project footprint and an additional 20 acres for construction laydown and temporary parking area, beyond what was identified in the 2014 Final Decision. The ground disturbance for laydown and temporary parking would largely occur in the former Plains All American Tank Farm site. There is known contamination below the existing above-ground storage tanks, distillate tank, and presence of fuel pipelines onsite. Staff understands the project owner is currently in discussions with the Department of Toxic Substances Control Chatsworth Office to identify, quantify and remediate past contamination issues at the HBGS. Existing and discovered contamination would be remediated prior to the construction of HBEP. The analysis of potential impacts related to the tank site remediation is discussed in the Waste Management section of this document.

The change in construction disturbance area does not require any changes to the existing Conditions of Certification. The owner would still be required to comply with **SOIL&WATER-1** and apply to the State Water Resources Control Board for coverage under the Clean Water Act construction storm water discharge permit to ensure no offsite water quality impacts. Site specific measures necessary to ensure any runoff from the Plains All American Tank Farm site disturbance would be included in the Stormwater Pollution Prevention Plan required for remediation, construction, and use of the laydown area.

OPERATION IMPACTS AND MITIGATION

Water Use

The proposed project would use less water than the licensed project. The 2014 Commission Decision approved the use of up to 134 AFY of water from the city of Huntington Beach for industrial operation. This project amendment proposes to reduce total water use to 120 AFY. This reduction results in a potentially beneficial impact by decreasing the demand on the supplier system by up to 14 AFY.

Coastal Flooding and Sea-Level Rise

The 2014 Decision evaluated the impact of coastal flooding on the reliability of HBEP. The conclusion was that HBEP had adequate protection from coastal flooding. While the conclusion remains the same for the proposed HBEP, staff presents some updated information regarding coastal flooding and sea-level rise below.

The United States Geological Survey has partnered with California public agencies and other coastal community stakeholders to develop a hazard assessment tool called the Coastal Storm Modeling System (CoSMoS). CoSMoS is a modeling system that predicts levels of coastal flooding and erosion due to both sea level rise and storms driven by climate change. It provides region-specific flood hazard projections at a detailed parcel scale along the California coast. It is based on an active scientific development approach that utilizes cutting-edge science to provide the optimum model outputs possible at this time. CoSMoS uses a combination of historic conditions and global climate models to project future conditions. It also provides flood projections specific for the bathymetry and topography of the modelled areas in Southern California. Staff considers CoSMoS to be the best available science for community planning in coastal zones in Southern California.

CoSMoS calculates 100-year storm water levels based on the contributions of multiple wave condition parameters. These contributions include wave runup, storm surge, seasonal effects, tide differences, and fluvial discharge backflow. Sea-level rise scenarios are later added to the calculated water levels (CCC2016d).

The latest version of CoSMos, version 3.0, is expected to be complete by summer 2016. Preliminary Phase I, 100-year storm data became available in 2015. Staff reviewed the available data to evaluate the risks to HBEP. Modelled sea-level rise scenarios in CoSMoS include 50 cm and 100 cm projections. The 2014 Decision contemplated sea-level rise of up to 61 cm (or 2.0 feet). Staff reviewed the CoSMoS 100-year storm with 100 cm sea-level rise inundation risk scenario, assuming it would over-predict the risk at the HBEP site. Staff constructed an inundation map using the data available from the CoSMoS (USGS2016). The resulting geospatial evaluation is included as **Soil and Water Resource Figure 1**. The data show that HBEP is not inundated during a 100-year storm, under a 100 cm sea-level rise scenario. Staff expects the risk of inundation to be lower if sea-level rise during the project life is less than shown in the figure.

COMPLIANCE WITH LORS AND STATE POLICIES

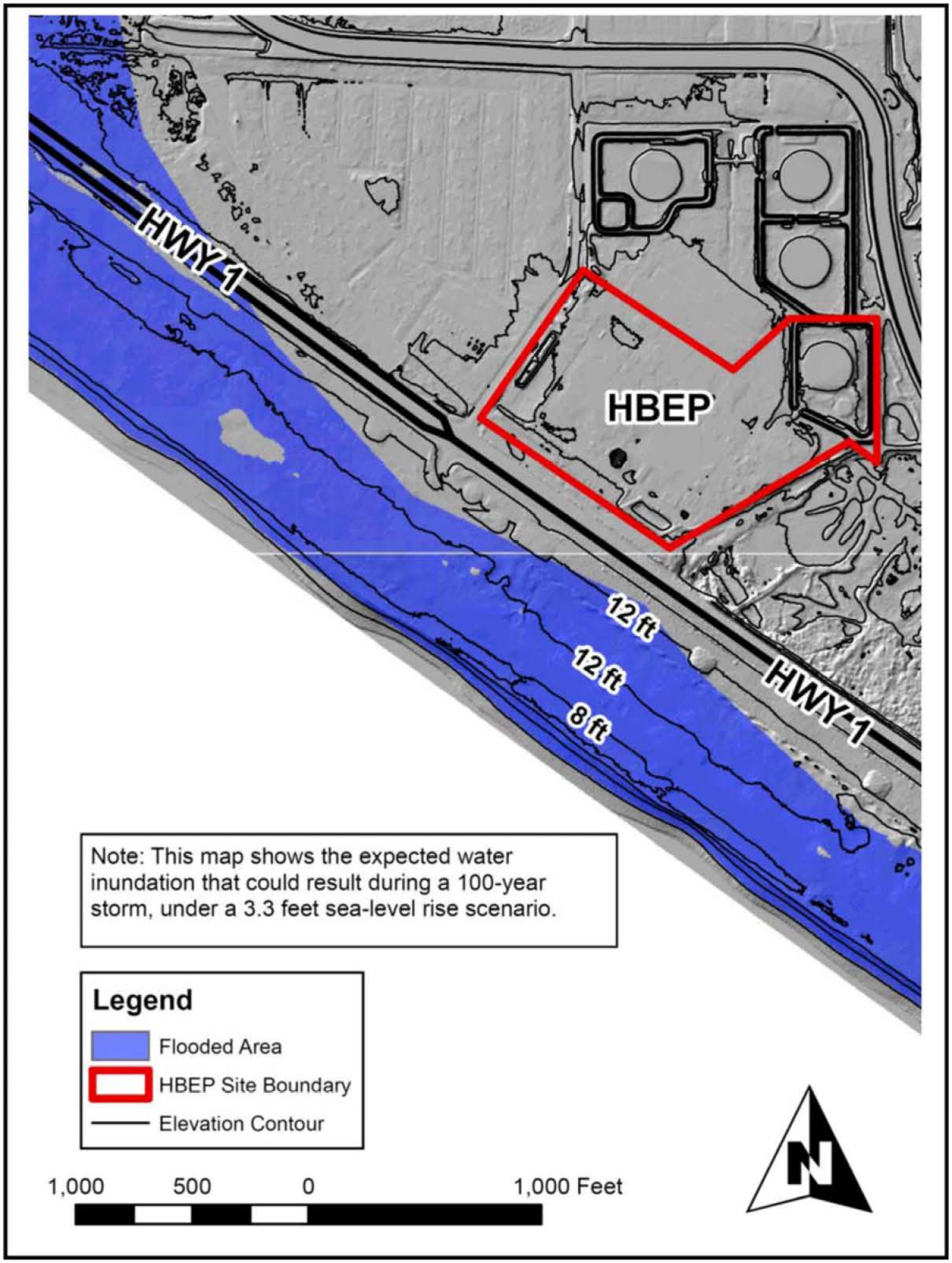
WATER SUPPLY ASSESSMENT

In this section staff updates the information relied on in the Decision.

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 Guidebook discusses how to manage water supplies and how to appropriately project future demands on a water supply system for the next 20 years, while considering new developments. Ultimately a WSA should provide evidence that verifies the sufficiency of, or the deficiencies in, a project’s water supply while also ensuring there is an adequate supply for existing users and future demand. The 2014 Decision should be updated to address recent city of Huntington Beach water supply data, relevant to the requirements of California Water Code Sections 10910 through 10915.

SOIL AND WATER RESOURCES - FIGURE 1
Huntington Beach Energy Project - Inundation Map



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: USGS, 2016

Required WSA Elements

Is the amended HBEP 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 apply to HBEP; 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 is one “project” definition that requires further consideration. Section (a) (7) requires a WSA if a project used an amount of water equivalent to a 500 dwelling unit project.

> *(a)(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.*

This requirement is the most difficult threshold in the list to interpret. Staff considered the following in making an interpretation about item (a)(7).

a) How much water does a 500 dwelling unit project use in California?

b) How much water does a 500 dwelling unit project use in the city of Huntington Beach?

c) What would staff assume a 500 dwelling unit project would use?

d) Would the city of Huntington Beach define the amended HBEP as a “project” under Water Code Section 10912?

e) Would the amended HBEP qualify as a “project” under Water Code Section 10912?

A. How much water does a 500 dwelling unit project use in California?

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.

Staff reviewed recent water use data for the state to test the use estimates provided by DWR. During 2015, the statewide average residential gallon per day per capita use rate was 86.0 (SWRCB2016). Census.gov reports that there was an average of 2.95 persons per household in California for years 2010-2014 (Census2016). This equates to 0.28 AF/DU, or 142 AF/500DUs.

The statewide average use for 2015 was very close to DWR’s low estimate per household. In the last few years California has experienced and unprecedented drought. Mandatory water use restrictions statewide have resulted in a substantial reduction in water use.

B. How much water does a 500 dwelling unit project use in the city of Huntington Beach?

Staff used two methods to estimate what 500 dwelling units would use in the city of Huntington Beach, both based on actual usage data from the city of Huntington Beach. The first method utilized data provided in the city of Huntington Beach's 2010 Urban Waste Management Plan (UWMP) (UWMP2010). The UWMP plan provides the total water delivered (and projected to be delivered) to residential units, single- and multi-family, in the city's service area. The UWMP also provides the number of single- and multi-family connections. **Soil & Water Table 3** below shows that the expected use for 500 dwelling units in the city of Huntington Beach would be between 151 and 168 AFY, averaging 163 AFY for the projected period 2010 through 2035.

Soil & Water Table 3
Summary of City of Huntington Beach Dwelling Unit Water Usage

	2010	2015	2020	2025	2030	2035
Single Family Use (AF)	14,707	13,754	15,526	16,029	16,252	16,384
Multi-Family Use (AF)	6,908	6,149	7,035	7,119	7,346	7,525
Single Family Units	44,147	44,420	45,459	47,464	48,725	49,562
Multi-Family Units	20,595	21,275	21,730	22,980	23,380	23,965
Total Water Used (AF)	21,615	19,903	22,561	23,148	23,598	23,909
Total Dwelling Units (AF)	64,742	65,695	67,189	70,444	72,105	73,527
Avg Water Used (AF/DU)	0.33	0.30	0.34	0.33	0.33	0.33
Avg AF / 500DUs	167	151	168	164	164	163

Using a slightly different method, staff reviewed water use data submitted by the city of Huntington Beach to the State Water Resources Control Board (SWRCB2016), which is shown in **Soil & Water Table 4** below. Staff assumed the water used in 2015 was used by 65,695 units, as was calculated by the city and shown in **Table 3** above. Based on data the city submitted to the SWRCB, the average rate of use per 500 homes in Huntington Beach was 126 AF in 2015. This lower use rate is consistent with city of Huntington Beach conservation standard imposed by the SWRCB, requiring a 20-percent reduction in residential per capita use due to the recent drought.

C. What would staff assume a 500 dwelling unit project would use?

As shown above, staff has four estimates of water use per 500 dwelling units, based on actual water use rates[1]. The lower estimate provided by DWR is 150 AFY. The statewide average in 2015 during the drought was 142 AFY. The most recently published UWMP for the city of Huntington Beach indicates an average use of 163 AFY. Data submitted by the city of Huntington Beach to the SWRCB for 2015, indicates 126 AFY per 500 dwellings. The range of estimates provided is from 126 AFY to 163 AFY. Staff believes all the provided estimates are equally valid.

Soil & Water Table 4
Summary of Residential Water Use in City of Huntington Beach, 2015

Year	Month	Total Use (gal)	R-GPCD	percent res	Total Use Res (gal)	Units	gal/unit	gal/500 units	AF/500 units
2015	Jan	617,781,720	69.1	0.68	420,091,570	65,695	6,395	3,197,287	10
2015	Feb	602,336,363	74.6	0.68	409,588,727	65,695	6,235	3,117,351	10
2015	Mar	720,750,771	80.6	0.68	490,110,525	65,695	7,460	3,730,197	11
2015	Apr	736,098,374	85.1	0.68	500,546,894	65,695	7,619	3,809,627	12
2015	May	710,779,718	79.5	0.68	483,330,208	65,695	7,357	3,678,592	11
2015	Jun	719,251,855	83.2	0.68	489,091,261	65,695	7,445	3,722,439	11
2015	Jul	725,540,787	86.0	0.72	522,389,367	65,695	7,952	3,975,869	12
2015	Aug	763,111,457	90.4	0.72	549,440,249	65,695	8,364	4,181,751	13
2015	Sep	688,328,554	86.6	0.74	509,363,130	65,695	7,753	3,876,727	12
2015	Oct	694,845,583	83.5	0.73	507,237,276	65,695	7,721	3,860,547	12
2015	Nov	649,421,894	80.6	0.73	474,077,983	65,695	7,216	3,608,174	11
2015	Dec	608,820,806	75.1	0.75	456,615,605	65,695	6,951	3,475,269	11
								Total	**126**

D. Would the city of Huntington Beach define the amended HBEP as a "project" under Water Code Section 10912?

No. Staff inquired with the city regarding the applicability of a WSA for the amended HBEP. The city provided a letter stating that a WSA would not need to be prepared for the project. The letter states that the project's proposed potable water demand would be less than one-half of the four year (Fiscal Year 2009/2010 to 2013/2014) billed average of 252 AFY, for Huntington Beach Generating Station. The project's proposed use would result in a net reduction in water delivery of at least 132 AFY (CITY2015a).

[1] The 2014 HBEP Decision limited the representative 500 dwelling units to low and very low income housing. The UWMP for Huntington Beach forecasts a mix of housing, with the majority being for moderate and high income.

E. Would the amended HBEP qualify as a “project” under Water Code Section 10912?

No. HBEP proposes to use up to 120 AFY, which is below the lowest estimate of use per 500 dwelling units, 126 AFY. HBEP would therefore not be considered a “project” under Water Code Section 10912. This conclusion is in agreement with the letter provided by the city of Huntington Beach Public Works Department, stating that a WSA does not need to be prepared for HBEP.

CUMULATIVE IMPACTS

The proposed amendment would result in a reduction in the net water demand on the city of Huntington Beach water supply system. Staff has not identified adverse environmental impacts that could result from the approval of the amended HBEP. There are no threats to existing populations near the proposed project identified in this analysis.

CONCLUSIONS AND RECOMMENDATIONS

Staff presented updated information about threats posed by sea-level rise and coastal flooding to the amended HBEP. This new information represents the best available science for planning-level decisions. Staff believes the information provided shows that HBEP has adequate protection from coastal flooding and sea-level rise during the project’s life.

The provided analysis demonstrates that the amended HBEP does not qualify as a “project” under Water Code Section 10912 and that a WSA does not need to be prepared. The Committee should re-analyze the conclusions of the 2014 Decision regarding the maximum amount of water to be used by the project alongside the new information provided in this analysis. This section augments the existing record to reflect current environmental conditions and policy considerations.

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 HBEP. Deleted text is in ~~strikethrough~~; new text is **bold and underlined**).

NPDES CONSTRUCTION PERMIT REQUIREMENTS

SOIL&WATER-1: The project owner shall manage stormwater pollution from HBEP construction activities by fulfilling the requirements contained in State Water Resources Control Board’s *National Pollutant Discharge Elimination System (NPDES) General Permit for Storm Water Discharges Associated with Construction and Land Disturbance Activities (Order No. 2009-0009-DWQ, NPDES No. CAS000002*) and all subsequent revisions and amendments. The project owner shall develop and implement a construction Storm Water Pollution Prevention Plan (SWPPP) for the construction of the HBEP project.

<u>Verification</u>: Thirty (30) days prior to site mobilization of HBEP construction activities, the project owner shall submit the construction SWPPP to the CBO and CPM for review and the SWRCB for review and comment. A copy of the approved construction SWPPP shall be kept accessible onsite at all times. Within 10 days of its mailing or receipt, the project owner shall submit to the CPM any correspondence between the project owner and the Santa Ana Regional Water Quality Control Board about the general NPDES permit for discharge of stormwater associated with construction and land disturbance activities. This information shall include a copy of the notice of intent and the notice of termination submitted by the project owner to the SWRCB.

HYDROSTATIC WATERDISCHARGE PERMIT REQUIREMENTS

SOIL&WATER-2: Prior to initiation of hydrostatic testing water discharge to surface waters, the project owner shall obtain a National Pollutant Discharge Elimination System permit for discharge to the Pacific Ocean. The project owner shall comply with the requirements of the Permit Order No. R8-2009-0003, NPDES NO. CAG998001 for hydrostatic testing water discharge. The project owner shall provide a copy of all permit documentation sent to the Santa Ana Regional Water Quality Control Board or State Water Quality Control Board to the CPM and notify the CPM in writing of any reported non-compliance.

<u>Verification</u>: Prior to construction mobilization, the project owner shall submit to the CPM documentation that all necessary NPDES permits were obtained from the Santa Ana Regional Water Quality Control Board or State Water Quality Control Board. Thirty (30) days prior to HBEP operation, the project owner shall submit to the CPM a copy of the relevant plans and permits received. The project owner shall submit to the CPM all copies of any relevant correspondence between the project owner and the Board regarding NPDES permits in the annual compliance report.

GROUNDWATER DISCHARGE PERMIT REQUIREMENTS

SOIL&WATER-3: Discharge of dewatering water shall comply with the Santa Ana Regional Water Quality Control Board (RWQCB) and State Water Resources Control Board regulatory requirements. The project owner shall submit a Report of Waste Discharge (RWD) to the compliance project manager (CPM) and RWQCB for determination of which regulatory waiver or permit applies to the proposed discharges. The project owner shall pay all necessary fees for filing and review of the RWD and all other related fees. Checks for such fees shall be submitted to the RWQCB and shall be payable to the State Water Resources Control Board. The project owner shall ensure compliance with the provisions of the waiver or permit applicable to the discharge. Where the regulatory requirements are not applied pursuant to a National Pollutant Discharge Elimination System permit, it is the Commission's intent is that the requirements of the applicable waiver or permit be enforceable by both the Commission and the RWQCB. In furtherance of that objective, the Commission hereby delegates the enforcement of the waiver or permit requirements, and associated monitoring, inspection, and annual fee collection authority, to the RWQCB. Accordingly, the Commission and the

RWQCB shall confer with each other and coordinate, as needed, in the enforcement of the requirements.

Verification: Prior to any dewatering water discharge, the project owner shall submit a RWD to the RWQCB to obtain the appropriate waiver or permit. The appropriate waiver or permit must be obtained at least 30 days prior to the discharge. The project owner shall submit a copy of any correspondence between the project owner and the RWQCB regarding the waiver or permit and all related reports to the CPM within 10 days of correspondence receipt or submittal.

NPDES INDUSTRIAL PERMIT REQUIREMENTS

SOIL&WATER-4: Prior to mobilization for construction, the project owner shall obtain a National Pollutant Discharge Elimination System permit for industrial waste and stormwater discharge to the Pacific Ocean. The project owner shall discharge to the same outfall currently utilized by the Huntington Beach Generating Station under the requirements of Order No. R8-2010-0062, NPDES No. CA0001163. The project owner shall provide a copy of all permit documentation sent to the Santa Ana or State Water Board to the CPM and notify the CPM in writing of any reported non-compliance.

Verification: Prior to construction mobilization, the project owner shall submit to the CPM documentation that all necessary NPDES permits were obtained from the Santa Ana or State Water Board. Thirty (30) days prior to HBEP operation, the project owner shall submit to the CPM a copy of the Industrial SWPPP. The project owner shall submit to the CPM all copies of any relevant correspondence between the project owner and the Board regarding NPDES permits in the annual compliance report.

WATER AND SEWER CONNECTIONS

SOIL&WATER-5: The project owner shall pay the city of Huntington Beach all fees normally associated with industrial connections to the city's sanitary sewer or water supply system as defined in the city's code, Title 14 Water and Sewers.

Verification: Prior to the use of the city's water or sewer system the owner shall provide the CPM documentation indicating that the city has accepted the project's connections to the water and sewer systems. Fees paid to the city shall be reported in the Annual Compliance Report (ACR) for the life of the project.

WATER USE AND REPORTING

SOIL&WATER-6: Water supply for project operation and construction shall be potable water supplied from the city of Huntington Beach. Water use for operation of the Huntington Beach Energy Project shall not exceed ~~134~~ **120** AFY; water use for construction shall not exceed 22 AFY. A monthly summary of water use shall be submitted to the CPM.

Verification: The project owner shall record HBEP operation water use on a daily basis and shall notify the CPM within 14 days upon forecast to exceed the maximum annual use as described above. Prior to exceeding the maximum use, the owner shall provide a plan to modify operations.

The project owner shall record HBEP construction water use on a daily basis and shall notify the CPM within 14 days upon forecast to exceed the maximum annual use of 22 AFY of potable water. Prior to exceeding the maximum use, the owner shall provide a plan to modify construction practices or offset excess water use.

The project owner shall submit a water use summary report to the CPM monthly during construction and annually in the ACR during operations for the life of the project. The annual report shall include calculated monthly range, monthly average, daily maximum within each month and annual use by the project in both gallons per minute and acre-feet. After the first year and for subsequent years, this information shall also include the yearly range and yearly average potable water used by the project.

WATER METERING

SOIL&WATER-7: Prior to the use of a water source during commercial operation, the project owner shall install and maintain metering devices as part of the water supply and distribution system to monitor and record in gallons per day the total volume(s) of water supplied to the HBEP from the water source. Those metering devices shall be operational for the life of the project and must be able to record the volume from each source separately.

Verification: At least thirty (30) days prior to use of any water source for HBEP operation, the project owner shall submit to the CPM evidence that metering devices have been installed and are operational. The project owner shall provide a report on the servicing, testing, and calibration of the metering devices in the annual compliance report.

REFERENCES

CCC 2016d - California Coastal Commission/Tom Luster (TN 210681). Total Water Level Contributions Near Huntington Beach. Submitted to CEC/Docket Unit on March 11, 2016

CENSUS 2016 - United States Census Bureau, State and County Quick Facts, website. Accessed at: http://quickfacts.census.gov/qfd/states/06000.html. Accessed on April 8, 2016.

CITY 2015a - Response Letter to the 10/26/15 Request for Water Supply Assessment, City of Huntington Beach Public Work Department. December 11, 2015. TN# 207017.

DWR 2003 - Guidebook for Implementation of Senate Bill 610 and Senate Bill 221 of 2001. California Department of Water Resources. October 8, 2003.

SWRCB 2016 - State Water Resources Control Board, Water Conservation Portal. Accessed on April 8, 2016. Accessed at: http://www.waterboards.ca.gov/water_issues/programs/conservation_portal/conservation_reporting.shtml

USGS 2016 - United State Geological Survey, Costal Storm Modelling System. Accessed March 2016, accessed at: https://walrus.wr.usgs.gov/coastal_processes/cosmos/socal3.0/index.html.

UWMP 2010 - 2010 Urban Water Management Plan, City of Huntington Beach. June 20, 2011.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
TRAFFIC AND TRANSPORTATION
John Hope

SUMMARY OF CONCLUSIONS

Staff reviewed potential traffic and transportation impacts previously analyzed for the licensed Huntington Beach Energy Project (HBEP). Staff concludes that the amended HBEP would not result in new significant traffic and transportation effects or increase the severity of previously identified significant effects. In accordance with California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the 2014 Commission Decision is necessary for traffic and transportation. The Committee may rely upon the environmental analysis and conclusions of the 2014 Commission Decision with regards to traffic and transportation and does not need to re-analyze them.

The amended HBEP would remain in compliance with applicable laws, ordinances, regulations, and standards (LORS) related to traffic and transportation. Although the proposed amended HBEP would require additional roadway improvements compared to the licensed HBEP, existing condition of certification **TRANS-4** would ensure the project owner complies with the city of Huntington Beach's requirements for encroachments into public rights-of-way.

INTRODUCTION

Staff reviewed the 2014 Commission Decision and analyzed the changes to the licensed HBEP, which include:

- Replacing Block 1 with a two-on-one combined-cycle gas turbine (CCGT) configuration,
- Replacing Block 2 as licensed with two simple-cycle gas turbine (SCGT) units,
- Using a natural-gas-fired auxiliary boiler to support the CCGT power block,
- Using a set of natural gas compressors in each power block,
- Constructing other equipment and facilities to be shared by both power blocks,
- Constructing the project on 30 acres within the footprint of the existing Huntington Beach Generating Station (HBGS), and
- Adding a 22-acre area for temporary construction laydown and construction worker parking at the former Plains All-American Tank Farm property.

SUMMARY OF THE DECISION

The Energy Commission’s Final Decision for the HBEP was published in November 2014. Based on the evidence presented in the original proceeding, the Energy Commission found and concluded that construction of the HBEP would add traffic to local roadways which would reduce the level of service (LOS) at the Beach Boulevard/ Pacific Coast Highway (PCH) and Brookhurst Street/ PCH intersections. To reduce these impacts, the project owner was required to implement a Traffic Control Plan (TCP) to ensure LOS on local roadways is not significantly degraded and to ensure the safety of the public and construction workers. In addition, the Commission required the project owner to implement a Parking and Staging Plan for all phases of construction to ensure that all project-related parking remains on-site or in designated off-site parking areas.

The Energy Commission also concluded that the HBEP’s thermal exhaust plumes could present a potential impact to helicopters and small aircraft if they were to fly over the HBEP at low altitude. To mitigate this impact, the Commission required the project owner to coordinate with the Federal Aviation Administration (FAA) to issue various notifications to pilots to advise them against direct overflight of the HBEP.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

No LORS applicable to the project have changed since the Commission Decision was published in October 29, 2014. Additionally, the proposed amendment would not trigger new LORS that may not have been applicable to the original project. The amended HBEP would remain in compliance with applicable LORS. As discussed further below, the amended HBEP would involve roadway improvements associated with the proposed expanded use of the Plains All American Tank Farm site. Existing condition of certification **TRANS-4** would ensure the project owner complies with the city of Huntington Beach’s requirements for encroachments into public rights-of-way.

ENVIRONMENTAL IMPACT ANALYSIS

Staff has reviewed the petition for potential environmental effects. Based on this review, staff determined that modification to the HBEP license would result in changes to the traffic and transportation environment related to construction parking, construction traffic generation, and thermal exhaust plumes.

CONSTRUCTION PARKING

Construction worker parking for construction of the HBEP and demolition of the existing power generating units at the HBGS would be provided by a combination of onsite parking and offsite parking. As with the licensed HBEP, a maximum of 330 parking spaces would be required during construction and demolition activities. The construction and demolition parking options discussed below would include approximately 28.9 acres (approximately 975 parking stalls).

The licensed HBEP included the following parking locations:

- 1.5 acres onsite at the HBGS (approximately 130 parking stalls)
- 3 acres of existing paved/graveled parking located adjacent to the HBEP across Newland Street (approximately 300 parking stalls)
- 2.5 acres of existing paved parking located at the corner of Pacific Coast Highway and Beach Boulevard (approximately 215 parking stalls)
- 1.9 acres at the former Plains All American Tank Farm site located adjacent to the HBEP site (approximately 170 parking stalls).

The amended HBEP would add an additional 20 acres (for a total of 21.9 acres) at the former Plains All American Tank Farm site (for a total of approximately 330 parking stalls). The expanded area would also be used for construction laydown.

To facilitate use of the Plains All American site for construction worker parking and as a construction laydown area, the project owner would construct a new entrance (two lanes in each direction) at the existing Magnolia and Banning signalized intersection. This intersection is currently controlled by an existing three-way traffic signal. The project owner would modify the intersection to a 4-way traffic signal in coordination with the city of Huntington Beach engineering and planning departments in regards to design and meeting the city's specifications. Construction workers who park at the Plains site would walk to the HBEP site via an existing bridge over the Huntington Beach Channel and a walking path. (HBEP 2015a, pg. 2-14) This walking path crosses land owned by the Huntington Beach Wetlands Conservancy (HBWC), which has expressed concern with the project owner's proposed use of the Plains All American site for construction worker parking. Specifically, HBWC states the use of this pathway crossing the wetlands is prohibited. (HBWC 2016) At the April 19, 2016, status conference, the project owner acknowledged HBWC's comments related to the pathway. The project owner responded by stating they would continue pursuing the use of the pathway but would revise the project description if an agreement cannot be reached. It should be noted that the licensed HBEP includes the operation of a shuttle from offsite parking areas which provide sufficient area to accommodate construction worker parking.

The existing condition of certification **TRANS-4** would ensure the project owner coordinates with the city of Huntington Beach prior to constructing any improvements to the Magnolia/Banning intersection. Specifically, condition of certification **TRANS-4** would require the project owner to provide the compliance project manager (CPM) with copies of all related permit(s) received from the city of Huntington Beach prior to any ground disturbance or obstruction of traffic that would occur with improvements to this intersection.

CONSTRUCTION TRAFFIC GENERATION

Implementation of the amended HBEP would result in fewer construction trips than the licensed HBEP. Based on the proposed construction activities and workforce estimates, the proposed amended HBEP would generate 638 daily one-way trips and 312 peak hour trips. In comparison, the licensed HBEP was estimated to generate 734 daily trips and 343 peak hour trips. Routes used for construction workers and truck deliveries, including heavy-haul routes, would not change with implementation of the proposed amended HBEP.

Magnolia Street

The project owner assumes that 100 percent of the construction workers for the proposed amended HBEP would park at the Plains All American site. Therefore, it is also assumed that a higher percentage of the project traffic would be distributed to Magnolia Street than what was previously evaluated for the licensed HBEP. The project owner evaluated potential traffic impacts to three intersections along Magnolia Avenue, including at Atlanta Avenue, Hamilton Avenue, and Pacific Coast Highway.

Traffic and Transportation Table 1 below shows the daily traffic volumes and volume-to-capacity (V/C) ratio for the existing plus project conditions on Magnolia Street between Garfield Avenue and Yorktown Avenue. As shown in the table, Magnolia Street would continue to operate at LOS C under the assumption that 100 percent of the workforce uses this roadway exclusively.

Traffic And Transportation Table 1
Construction Roadway Segment LOS

Roadway Segment	Number of Lanes	Average Annual Daily Volume	Construction Volume	Total Volume with Construction	Construction V/C Ratio	Construction LOS
Magnolia Street between Garfield Avenue and Yorktown Avenue	4	23,000	638	23,638	0.79	C

Source: HBEP 2015a, page 5-12-5

The project owner also assessed the operating conditions of the intersections on Magnolia Street closest to the Plains All American Tank Farm. **Traffic and Transportation Table 2** below shows the existing AM and PM peak hour intersection LOS for three intersections along Magnolia Street. As shown in the table, the intersections currently operate at LOS A and are estimated to have sufficient capacity to accommodate the increase in project-related trips during both peak hours. This conclusion is based on the minimal increase of traffic along Magnolia Street (3 percent of average annual daily volume) that would occur during construction. Increased traffic generated during construction of the proposed amended HBEP would not have the potential to substantially change the existing operating conditions of Magnolia Street (estimated to operate at LOS C) or intersections which currently operate at LOS A.

Traffic And Transportation Table 2
Existing Intersection LOS

Intersection	AM Peak Hour		PM Peak Hour	
	ICU[1]	LOS	ICU[1]	LOS
Magnolia Street at Atlanta Avenue	0.53	A	0.49	A
Magnolia Street at Hamilton Avenue	0.49	A	0.55	A
Magnolia Street at Pacific Coast Highway	0.56	A	0.57	A

[1] For signalized intersections, the intersection capacity utilization (ICU) methodology is used by the city of Huntington Beach to evaluate the intersection LOS. This methodology sums the V/C ratios for the critical movements of an intersection and results in a total V/C for an intersection, which correlates to a LOS for the intersection.

THERMAL PLUMES

Staff conducted an updated thermal plume analysis of the amended HBEP's combustion turbines (simple- and combined-cycle units), auxiliary boiler, air cooled condenser, and fin fan coolers. The analysis concluded that the air-cooled condenser could cause the greatest risk to any light aircraft that may fly over the HBEP site, with thermal plumes predicted to drop below the critical velocity threshold of 4.3 meters per second (m/s) at 2,200 feet above ground level (AGL). For the licensed HBEP, the thermal plumes were predicted to drop below 4.3 m/s at 1,740 feet AGL. The updated thermal plume velocity analysis is provided in **Appendix TT-1**. However, as discussed in the Commission Decision, pilots would have the ability to safely avoid the HBEP thermal plumes because of the small number of aircraft likely to fly over the HBEP and the presence of available flight paths to avoid the thermal plumes (CEC 2014bb, page 6.2-24). Staff has proposed changes to condition of certification **TRANS-7** (Pilot Notification and Awareness) to reflect the increased height of the thermal plumes to be avoided, to update the names of aviation publications and charts, and to improve clarity.

CUMULATIVE IMPACTS

Based on the evidence presented in the original proceeding, the Energy Commission found and concluded that trips generated by 26 known past, current, and probable future projects near the proposed HBEP project and located within the transportation network used by HBEP may combine with HBEP trips to result in cumulative impacts to the LOS of nearby highways, roadways, and intersections. **Traffic and Transportation Table 11** in the Final Commission Decision lists the locations of these cumulative projects (HBEP 2014bb). The Commission concluded that, with imposition and implementation of conditions of certification **TRANS-1** through **TRANS-4**, all traffic related direct impacts would be less than significant, and therefore, the project's incremental effects would not be cumulatively considerable. Staff has identified no new projects within the transportation network used by HBEP since publication of the Commission Decision; therefore, no new analysis or changes to the cumulative impact conclusions for the amended HBEP are required.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the proposed amendment would not result in new significant traffic and transportation effects, or increased the severity of previously identified significant effects. Existing conditions of certification **TRANS-1** through **TRANS-6**, and **TRANS-7** as modified to reflect the increased height of the thermal plumes, would be sufficient to reduce the amended HBEP's traffic impacts to a less-than-significant level. Therefore, staff concludes that the findings of fact from the licensed HBEP Commission Decision would still apply to the amended HBEP. In accordance with CEQA Guidelines section 15162, staff concludes that no supplementation to the 2014 Commission Decision is necessary for traffic and transportation. The Committee may rely upon the environmental analysis and conclusions of the 2014 Commission Decision with regards to traffic and transportation and does not need to re-analyze them.

Subsequent to the HBEP Decision, staff became aware of updated sectional charts and changes to FAA circulars and regulations related to the safe operation of aircraft near a power plant. Therefore, staff recommends minor administrative changes to conditions of certification **TRANS-6** and **TRANS-7** to reflect these updates and changes. Staff proposes deleting the portions of the Verification for **TRANS-6** related to obstruction marking and lighting on <u>permanent</u> structures, which appear to have been included in error. **TRANS-6** relates to the marking and lighting per FAA regulations of objects taller than 200 feet AGL (i.e., construction equipment). As discussed in the Commission Decision, the licensed HBEP's tallest permanent structures (its 120-foot tall exhaust stacks) would not exceed this threshold and neither would the amended HBEP's tallest permanent structures (150-foot tall stacks). Staff has proposed other minor changes to **TRANS-7** to improve clarity and implementation of certain elements of the condition.

The amended HBEP would remain in compliance with applicable LORS related to traffic and transportation. Although the amended HBEP would require improvements to the Magnolia Street/Banning Avenue intersection, existing condition of certification **TRANS-4** would ensure the project owner complies with the city of Huntington Beach requirements for encroachments into public rights-of-way prior to constructing any improvements.

Socioeconomics Figure 1 shows no presence of an environmental justice population living in the project's six-mile radius.

PROPOSED CONDITIONS OF CERTIFICATION

Conditions of certification **TRANS-3** through **TRANS-5** do not require any changes. Staff proposes two minor editorial changes to conditions **TRANS-1** and **TRANS-2** for clarity. As discussed above, staff proposes minor changes to Conditions of Certification **TRANS-6** and **TRANS-7**. Deleted text is in ~~strikethrough~~. New text is **<u>bold</u>** and **<u>underlined</u>**.

TRANS-1 ROADWAY USE PERMITS AND REGULATIONS

The project owner shall apply to each jurisdiction along the route of travel from the Port of Long Beach to the **Alamitos Generating Station (**AGS**)** and/or project site for all necessary transportation permits and shall comply with all conditions imposed by the California Department of Transportation (Caltrans) and other relevant jurisdictions, including, but not limited to, Orange County, Los Angeles County, and the cities of Huntington Beach, Long Beach, and Seal Beach, on vehicle sizes and weights, driver licensing, and truck routes.

Verification: In the Monthly Compliance Reports (MCRs), the project owner shall submit copies of all applications submitted and any permits received during that reporting period to the Compliance Project Manager (CPM) In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.

TRANS-2 RESTORATION OF ALL PUBLIC ROADS, EASEMENTS, AND RIGHTS-OF-WAY

The project owner shall restore all public rights-of-way, including but not limited to streets, highways, roads, easements, and intersections, that have been damaged due to project-related construction and demolition activities. Restoration of significant damage which could cause hazards (such as potholes) must take place immediately after the damage has occurred. The restoration shall be completed in a timely manner to the road's original condition in compliance with the applicable jurisdiction's standards.

Verification: Prior to the start of site mobilization, the project owner shall photograph or videotape all public rights-of-way segments that may be affected by project-related traffic. The project owner shall provide the photograph or videotape to the CPM and the affected local jurisdiction(s). The project owner shall coordinate with each jurisdiction regarding planned improvement activities on affected public rights-of-way.

If damage to public roads, easements, or rights-of-way occurs ~~is detected~~, the project owner shall notify the CPM and shall enter into an agreement with each affected local jurisdiction for implementing a roadway repair/rehabilitation program, including any necessary repairs before the end of construction. At a minimum, roads damaged by construction and demolition activities shall be repaired to a structural condition equal to that which existed prior to construction and demolition activity. Following completion of any public right-of-way repairs, the project owner shall provide proof to the CPM from each affected jurisdiction of its satisfaction with the repairs.

TRANS-3 TRAFFIC CONTROL PLAN

The project owner shall prepare and implement a Traffic Control Plan (TCP) for the HBEP's construction and operations traffic. The TCP shall address the movement of workers, vehicles, and materials, including arrival and departure schedules and designated workforce and delivery routes. The project owner shall consult with Caltrans and all applicable local jurisdictions, including, but not limited to, Orange County, Los Angeles County, and the cities of Huntington Beach, Long Beach, and Seal Beach, in the preparation and implementation of the Traffic Control Plan (TCP). The project owner shall submit the proposed TCP to Caltrans and applicable local jurisdictions in sufficient time for review and comment, and to the CPM for review and approval prior to the proposed start of demolition and construction and implementation of the plan.

The Traffic Control Plan (TCP) shall include:

1. Provisions for redirection of construction traffic with a flag person as necessary to ensure traffic safety and minimize interruptions to non-construction related traffic flow,

2. Placement of necessary signage, lighting, and traffic control devices at the project construction site and lay-down areas;

3. A heavy-haul plan addressing the transport and delivery of heavy and oversized loads requiring permits from the California Department of Transportation (Caltrans), other state or federal agencies, and/or the affected local jurisdictions including Los Angeles county, Orange county, city of Long Beach, city of Seal Beach, and city of Huntington Beach;

4. Location and details of construction along affected roadways at night, where permitted;

5. Temporary closure of travel lanes or disruptions to street segments and intersections during construction activities;

6. Traffic diversion plans (in coordination all applicable local jurisdictions and Caltrans) to ensure access during temporary lane/road closures;

7. Access to residential and/or commercial property located near construction work and truck traffic routes;

8. Assurance of access for emergency vehicles to the project site;

9. Advance notification to residents, businesses, emergency providers, and hospitals that would be affected when roads may be partially or completely closed;

10. Identification of safety procedures for exiting and entering the site access gate;

11. Parking/Staging Plan for all phases of project construction and operation to require all project-related parking to be on-site or in designated off-site parking areas. The Parking/Staging Plan shall prohibit use of the Huntington Beach City parking area unless the CPM determines that there are insufficient parking spaces available at the other parking facilities identified in this Decision.

Verification: At least 60 calendar days prior to the start of construction, the project owner shall submit the TCP to the applicable agencies for review and comment and to the CPM for review and approval. The project owner shall also provide the CPM with a copy of the transmittal letter to the agencies requesting review and comment.

At least 30 calendar days prior to the start of construction, the project owner shall provide copies of any comment letters received from the agencies, along with any changes to the proposed development plan, to the CPM for review and approval.

TRANS-4 ENCROACHMENT INTO PUBLIC RIGHTS-OF-WAY

Prior to any ground disturbance, improvements, or obstruction of traffic within any public road, easement, or right-of-way, the project owner or its contractor(s) shall coordinate with all relevant jurisdictions, including, but not limited to, Orange County, Los Angeles County, and the cities of Huntington Beach, Long Beach, and Seal Beach, and Caltrans, to obtain all required encroachment permits and comply with all applicable regulations.

Verification: At least 10 days prior to ground disturbance or interruption of traffic in or along any public road, easement, or right-of-way, the project owner shall provide copies of all permit(s) received from Caltrans or any other affected jurisdiction/s to the CPM. In addition, the project owner shall retain copies of the issued/approved permit(s) and supporting documentation in its compliance file for a minimum of 6 months after the start of commercial operation.

TRANS-5 HAZARDOUS MATERIALS

The project owner shall ensure that permits and/or licenses are secured from the California Highway Patrol, Caltrans and all other relevant jurisdictions for the transport of hazardous materials.

Verification: The project owner shall include in the MCRs copies of all permits/ licenses acquired by the project owner and/or subcontractors concerning the transport of hazardous substances during that reporting period.

TRANS-6 OBSTRUCTION MARKING AND LIGHTING

The project owner shall install blinking obstruction marking and lighting on any construction equipment that exceeds 200 feet in height in accordance with FAA requirements, as expressed in the **FAA Advisory Circular 70/7460-1L (or current circular in effect).**~~following documents:~~

~~o FAA Advisory Circular 70/7460-1K~~

~~o FAA Safety Alert for Operators (SAFO) 09007.~~

Lighting shall be operational 24 hours a day, 7 days a week for the duration of project construction. Upgrades to the required lighting configurations, types, location, or duration shall be implemented consistent with any changes to FAA obstruction marking and lighting requirements.

Verification: At least 60 days prior to the presence of any construction equipment which exceeds 200 feet in height, the project owner shall submit to the CPM for approval final design plans for construction equipment depicting the required air traffic obstruction marking and lighting.

~~At least 60 days prior to plant operation, the project owner shall install of permanent obstruction marking and lighting consistent with FAA requirements and shall inform the CPM in writing within 10 days of installation. The lighting shall be inspected and approved by the CPM (or designated inspector) within 30 days of installation.~~

~~At least 10 days prior to installation of permanent obstruction marking and lighting, the project owner shall provide the CBO and CPM proof in writing of approval by the FAA for all structure marking and lighting.~~

TRANS-7 PILOT NOTIFICATION AND AWARENESS

The project owner shall initiate the following actions to ensure pilots are aware of the project location and potential hazards to aviation:

- Submit a letter to the FAA requesting a Notice to Airmen (NOTAM) be issued advising pilots of the location of the HBEP and recommending avoidance of overflight of the project site below ~~1,740~~ **2,200** feet AGL. The letter should also request that the NOTAM be maintained in active status until all navigational charts and Airport Facility Directories (AFDs) have been updated.
- Submit a letter to the FAA requesting a power plant depiction symbol be placed at the HBEP site location on the **Los Angeles**~~San Diego~~ Sectional Chart with a notice to "avoid overflight below ~~1,740~~ **2,200** feet AGL".
- **Submit a letter** ~~R~~**r**equest**ing** that Southern California **Terminal Radar Approach Control (**TRACON**)** submit aerodrome remarks describing the location of the HBEP plant and advising against direct overflight below ~~1,740~~ **2,200** feet AGL to the:
- FAA ~~AeroNav Services, formerly the FAA National Aeronautical Charting Office (~~Airport/Facility Directory~~)~~ **- Southwest U.S.**
- Jeppesen Sanderson Inc. (~~JeppGuide Airport Directory,~~ **Airway Manual Services -** Western ~~Region~~ **U.S. Airport Directory**)
- ~~**Airguide Publications (Flight Guide, Western States)**~~ **Pilot's Guide to California Airports**

Verification: Within 30 days following the start of construction, the project owner shall submit draft language for the letters of request to the FAA ~~(including~~ **and** Southern California TRACON~~)~~ to the CPM for review and approval.

Within ~~At least~~ 60 days ~~prior to the start of operations,~~ **after CPM approval of draft language for the letters of request to the FAA and Southern California TRACON,** the project owner shall submit the required letters of request to the FAA and ~~request that~~ **to** Southern California TRACON **to** submit aerodrome remarks to the listed agencies. The project owner shall submit copies of these requests to the CPM. A copy of any resulting correspondence shall be submitted to the CPM within 10 days of receipt.

If the project owner does not receive a response from any of the above agencies within 45 days of the request (or by 15 days prior to the start of operations) the project owner shall follow up with a letter to the respective agency/ies to confirm implementation of the request. A copy of any resulting correspondence shall be submitted to the CPM within 10 days of receipt.

The project owner shall contact the CPM within 72 hours if notified that any or all of the requested notices cannot be implemented. Should this occur, the project owner shall appeal such a determination, consistent with any established appeal process and in consultation with the CPM. A final decision from the jurisdictional agency denying the request, as a result of the appeal process, shall release the project owner from any additional action related to that request and shall be deemed compliance with that portion of this condition of certification.

REFERENCES

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

FAA 2015 - *Aeronautical Information Manual, Section 7−5−15. Avoid Flight in the Vicinity of Exhaust Plumes (Smoke Stacks and Cooling Towers)*. December 10, 2015.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HBEP 2014j - City of Huntington Beach Comments Regarding Final Staff Assessment, dated June 26, 2014 (TN 202629). Submitted to CEC/Docket Unit on June 30, 2014.

HBWC 2016 - Huntington Beach Wetlands Conservation / Gordon W. Smith (tn211134). Comments of the Huntington Beach Energy Projects' Petition to Amend, dated 04/18/2016. Submitted to CEC/Dockets Unit on 04/18/2016.

APPENDIX TT-1: PLUME VELOCITY ANALYSIS

Wenjun Qian, Ph.D., P.E.

INTRODUCTION

The following provides the assessment exhaust stack plume vertical velocities of the Amended Huntington Beach Energy Project (Amended HBEP) combustion turbines, auxiliary boiler, air cooled condenser (ACC) and fin fan coolers. Staff completed calculations to determine the worst-case vertical plume velocities at different heights above the stacks based on the project owner's proposed facility design, with staff corrections to some of the operational data. The purpose of this appendix is to provide documentation of the method used to estimate worst-case vertical plume velocity estimates to assist evaluation of the project's impacts on aviation safety in the vicinity of the Amended HBEP.

SUMMARY OF THE DECISION

On October 29, 2014, the Energy Commission approved the HBEP as a 939 MW (nominal output) combined cycle power plant with two power blocks. Each power block would consist of three Mitsubishi Heavy Industries 501DA gas turbine generators coupled with one steam turbine, in a combined cycle configuration. The Final Commission Decision (CEC 2014bb) of HBEP concluded that the average velocity of the gas turbines drops below 4.3 m/s at the height of 1,740 feet (with two plumes fully merged). The Final Commission Decision also shows that the vertical plume velocity for the air cooled condenser (ACC) would drop below 4.3 m/s at a lower height, between 1,000 and 1,100 feet above ground level (AGL).

PROJECT DESCRIPTION

The Amended HBEP would be a natural-gas-fired, combined-cycle and simple-cycle, air-cooled electrical generating facility located on the site of the existing Huntington Beach Generating Station (HBGS) in Huntington Beach, California. The combined-cycle power block would consist of one two-on-one combined-cycle unit – two GE Frame 7FA.05 gas turbines, two unfired heat recovery steam generators (HRSGs), one steam turbine generator, one air-cooled condenser, one natural-gas-fired auxiliary boiler, and related ancillary equipment. The other power block would include two simple cycle GE LMS-100PB combustion turbines with one fin-fan cooler each and their separate ancillary equipment.

PLUME VELOCITY CALCULATION METHOD

SPILLANE APPROACH

Staff uses a calculation approach from a technical paper (Best 2003) to estimate the worst-case plume vertical velocities for vertical turbulence from plumes such as the Amended HBEP stacks and cooling system. The calculation approach, which is also known as the “Spillane approach”, used by staff is limited to calm wind conditions, which are the worst-case wind conditions. The Spillane approach uses the following equations to determine vertical velocity for single stacks during dead calm wind (i.e., wind speed = 0) conditions:

(1) $(V*a)^3 = (V*a)_o^3 + 0.12*F_o*[(z-z_v)^2-(6.25D-z_v)^2]$

(2) $(V*a)_o = V_{exit}*D/2*(T_a/T_s)^{0.5}$

(3) $F_o = g*V_{exit}*D^2*(1-T_a/T_s)/4$

(4) $Z_v = 6.25D*[1-(T_a/T_s)^{0.5}]$

Where: V = vertical velocity (m/s), plume-average velocity
a = plume top-hat radius (m, increases at a linear rate of a = $0.16*(z- z_v)$
F_o= initial stack buoyancy flux m^4/s^3
z = height above ground (m)
z_v= virtual source height (m)
V_{exit}= initial stack velocity (m/s)
D = stack diameter (m)
T_a= ambient temperature (K)
T_s= stack temperature (K)
g = acceleration of gravity (9.8 m/s^2)

Equation (1) is solved for V at any given height above ground that is above the momentum rise stage for single stacks (where z > 6.25D) and at the end of the plume merged stage for multiple plumes. This solution provides the plume-average velocity for the area of the plume at a given height above ground; the peak plume velocity would be two times higher than the plume-average velocity predicted by this equation. The stack buoyancy flux (Equation 3) is a prominent part of Equation (1). The calm condition calculation basis clearly represents the worst-case conditions, and the vertical velocity will decrease substantially as wind speed increases.

For multiple stack plumes, where the stacks are equivalent as is the case for HBEP, the multiple stack plume velocity during calm winds is calculated by staff in a simplified fashion, presented in the Best Paper as follows:

(5) $V_m = V_{sp}*N^{0.25}$

Where: V_m = multiple stack combined plume vertical velocity (m/s)
V_{sp} = single plume vertical velocity (m/s), calculated using Equation (1)
N = number of stacks

This simplified multiple stack plume velocity calculation method predicts somewhat lower velocity values than the full Spillane approach methodology for multiple plumes as given in data results presented in the Best paper (Best 2003). However, for a long linear set of plumes, such as the ACC designed for the Amended HBEP project, it is very unlikely that all plumes can merge fully to allow this velocity given the stack separation and the height/atmospheric conditions needed for them to fully merge. Therefore the use of this approach will likely over predict the combined plume velocities in this case.

MITRE EXHAUST PLUME ANALYZER

On September 24, 2015, the Federal Aviation Administration (FAA) released a guidance memorandum (FAA 2015) recommending that thermal plumes be evaluated for air traffic safety. FAA determined that the overall risk associated with thermal plumes in causing a disruption of flight is low. However, it determined that such plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight (such as take-off and landing). In this memorandum a new computer model, different than the analysis technique used by staff and identified above as the Spillane Approach, is used to evaluate vertical plumes for hazards to light aircraft. It was prepared under FAA funding and available for use in evaluating exhaust plume impacts.

This new model, the MITRE Corporation's Exhaust Plume Analyzer (MITRE 2012), was identified by the FAA as a potentially effective tool to assess the impact that exhaust plumes may impose on flight operations in the vicinity of airports (FAA 2015). The Exhaust Plume Analyzer was developed to evaluate aviation risks from large thermal stacks, such as turbine exhaust stacks. The model provides output in the form of graphical risk probability isopleths ranging from 10^{-2} to 10^{-7} risk probabilities for both severe turbulence and upset conditions for four different aircraft sizes. However, at this time the Exhaust Plume Analyzer model cannot be used to provide reasonable risk predictions on variable exhaust temperature thermal plume sources, such as cooling towers and air cooled condensers.

The FAA has not provided guidance on how to evaluate the risk probability isopleth output of the Exhaust Plume Analyzer model, but states in their memorandum that they intend to update their guidance on near-airport land use, including evaluation of thermal exhaust plumes, in fiscal year 2016. However, MITRE Corporation is suggesting that a probability of severe turbulence at an occurrence level of greater than 1×10^{-7} (they call this a Target Safety Level) should be considered potentially significant. This is equivalent to one occurrence of severe aircraft turbulence in 10 million flights. For the past 50 years, the MITRE Corporation has provided air traffic safety guidance to FAA, and their recommended Target Safety Level is based on this experience (MITRE 2016).

Additionally, the MITRE model has a probability of occurrence plot limitation. While it provides output for predict plumes up to a maximum height of 3,500 feet above ground, the meteorological data that is used by the model is currently limited to a maximum height of 3,000 feet, so any higher altitudes simply reuse the 3,000 foot meteorological data. The model was developed with the assumption that a plume would not rise higher than 3,000-3,500 feet above ground level, so the modeling output was terminated at that height[1]. The effort to expand the data set and model to work properly at altitudes above 3,000 feet above ground level is such that the MITRE Corporation would need additional funding.

The MITRE Exhaust Plume Analyzer model uses site specific computer-generated, three dimensional meteorological data (atmospheric temperature and wind speed, varying with height above ground at the specific site location) combined with a series of aircraft conditions related to the determination of turbulence effects and upset to develop the modeling output. The data sources used to create the site specific meteorological data are from the National Oceanic and Atmospheric Administration's National Weather Service (NWS). These computer-generated data are averaged over 13-kilometer grid cells using a model covering the continental United States. The specific NWS measuring stations that provide this data were not identified in the model documentation. The model uses three years of the computer-generated site specific hourly meteorological data to perform these calculations (MITRE 2012).

Staff conducted a preliminary evaluation using the MITRE model for the proposed GE 7FA.05 turbines and GE LMS-100PB turbines plumes, and results for the level of significance recommended by MITRE Corporation (1×10^{-7}) were above 3,000 feet above ground, outside the recommended output range of the model and above the 3,500 foot level provided as the highest extent in the model's graphical output files. At this time staff does not believe the MITRE model should be used for final work products until the vertical axis is extended, the significance threshold is verified by the FAA and the model capabilities are enhanced to include other thermal plume sources such as cooling towers and air-cooled condensers.

STAFF ANALYSIS

This appendix uses the Spillane Approach method to be consistent with staff assessments done for other projects and because the Spillane Approach is described in the FAA materials as providing similar risk assessments for light aircraft. As stated above, staff will consider using the new MITRE method to the extent that it is applicable after conducting further review of the FAA methodology and once FAA develops guidance on how to evaluate the output of the Exhaust Plume Analyzer.

[1] This recommendation seems to be based on MITRE's worst case exhaust assumptions that are similar to the exhaust conditions of a GE LM6000 gas turbine operating in simple cycle mode. However, there are many larger turbines operating in simple cycle mode, such as the GE LMS100 gas turbines proposed for the Amended HBEP that have about twice the thermal exhaust output of a GE LM6000 gas turbine.

EQUIPMENT DESIGN AND OPERATING PARAMETERS

GE 7FA.05 COMBUSTION GAS TURBINE DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the GE 7FA.05 combustion gas turbine stacks are provided in **Plume Velocity Table 1**. Staff chose four scenarios from the project owner-provided modeling inputs from the Petition to Amend (PTA) Appendix 5.1B and Appendix 5.1C (HBEP 2015a). Operating parameters chosen were for ambient temperatures of 32, 65.8, and 110 degree Fahrenheit (ºF) at maximum turbine loads to compute worst-case vertical plume velocities. Therefore the exhaust operating parameters shown correspond to full load operation for the corresponding ambient conditions.

Plume Velocity Table 1
GE 7FA.05 CTG Exhaust Parameters

Parameter	**GE 7FA.05**			
Stack Height	150 ft. (45.72 meters)			
Stack Diameter	20 ft. (6.10 meters)			
CTG Load (%)	100			
Ambient Temperature (°F)	32	65.8	110	
With Inlet Air Cooling	No	No	Yes	No
Exhaust Temperature (°F)	216	215	221	223
Exhaust Velocity (ft/s)	66.95	66.21	66.36	58.91
Exhaust Flow Rate (1000 lb/hr)	4,360	4,307	4,268	3,797

Source: HBEP 2015a

GE LMS-100PB COMBUSTION GAS TURBINE DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the GE LMS-100PB combustion gas turbine stacks are provided in **Plume Velocity Table 2**. Staff chose three scenarios from the project owner-provided modeling inputs from the Petition to Amend (PTA) Appendix 5.1B and Appendix 5.1C (HBEP 2015a). Operating parameters chosen were for ambient temperatures of 32, 65.8, and 110 degree Fahrenheit (ºF) at maximum turbine loads to compute worst-case vertical plume velocities. Therefore the exhaust operating parameters shown correspond to full load operation for the corresponding ambient conditions.

Plume Velocity Table 2
GE LMS-100PB CTG Exhaust Parameters

Parameter	GE LMS-100PB		
Stack Height	80 ft. (24.38 meters)		
Stack Diameter	13.5 ft. (4.11 meters)		
CTG Load (%)	100		
Ambient Temperature (°F)	32	65.8	110
With Inlet Air Cooling	No	Yes	Yes
Exhaust Temperature (°F)	789	794	848
Exhaust Velocity (ft/s)	109.18	108.66	96.61
Exhaust Flow Rate (1000 lb/hr)	1,754	1,746	1,473

Source: HBEP 2015a

AUXILIARY BOILER DESIGN AND OPERATING PARAMETERS

Plume Velocity Table 3 shows the design and operating parameter data for the auxiliary boiler stack, which were provided by the project owner in the PTA (HBEP 2015a). Staff chose the operating parameters (shown in **Plume Velocity Table 3**) which correspond to the maximum heat input case to compute worst-case vertical plume velocities.

Plume Velocity Table 3
Auxiliary Boiler Exhaust Parameters

Parameter	Auxiliary Boiler
Stack Height	80 ft. (24.38 meters)
Stack Diameter	3 ft. (0.91 meters)
Exhaust Temperature (°F)	318
Exhaust Velocity (ft/s)	69.6
Exhaust Flow Rate (Actual Cubic Feet per Minute [ACFM])	29,473

Source: HBEP 2015a

AIR-COOLED CONDENSER DESIGN AND OPERATING PARAMETERS

Plume Velocity Table 4 shows the design and operating parameter data for the air-cooled condenser (ACC) for the combined-cycle power block. The project owner provided the data in Data Responses Set 1 (HBEP 2015i). Staff noticed that the project owner-provided outlet air flow rates, outlet air exit velocities, and cell dimensions of the ACC are internally inconsistent with each other. Staff measured the diameter of each fan of the ACC from PTA Figure 2.1-2 General Arrangement/Site Plan (HBEP 2015a). Staff recalculated the outlet air exit velocities using the project owner-provided outlet air flow rates and staff-measured fan diameter. The staff-measured fan diameter and staff-calculated outlet air exit velocities are shown in **Plume Velocity Table 4** with an asterisk symbol (*).

FIN FAN COOLER DESIGN AND OPERATING PARAMETERS

Plume Velocity Table 5 shows the design and operating parameter data for each of the fin fan coolers for the simple-cycle power block. The project owner originally provided the data for the fin fan coolers in Data Responses Set 1 (HBEP 2015i). However, staff noticed that the project owner-provided heat rejection, outlet air flow rates, outlet air exit velocities, and cell dimensions of the fin fan coolers are internally inconsistent with each other. Staff requested the project owner to provide performance data sheets from the vendor and clarify the inconsistencies. The project owner provided follow-up vendor data sheets (HBEP 2016o) for the fin fan coolers. Staff recalculated the outlet air exit velocities and heat rejection rates using the air flow rates, inlet and outlet air temperatures from the vendor data sheets (HBEP 2016o), and the cell diameter from Data Responses Set 1 (HBEP 2015i). Staff corrected the 32ºF ambient temperate case exhaust data using mass and energy balance calculations based on the vendor data supplied by the project owner and the number of fans in operation (12 fans in operation in the 32ºF case rather than 28). The staff-calculated values are shown in **Plume Velocity Table 5** with an asterisk symbol (*).

Plume Velocity Table 4
Air-Cooled Condenser Exhaust Parameters

Parameter	Combined-Cycle Air-Cooled Condenser		
Number of Cells	30		
Cell Height (ft)	53.1		
Cell Diameter (ft)	43.9 (L) x 43.1 (W)		
Fan Diameter (ft) [a]	40*		
Distance Between Cells (ft)	0 ft (adjoining cells share a single column)		
Ambient Temperature	32	65.8	110
Ambient Relative Humidity	87%	58%	8%
Number of Cells in Operation	13	30	28
Heat Rejection (MW)	369.4	378.6	400.9
Outlet Air Temperature (°F)	90.9	92.7	142.2
Outlet Air Exit Velocity (ft/s) [b]	21.79*	21.14*	20.86*
Outlet Air Flow (lb/hr)	92,142,000	205,538,400	173,790,000

Source: HBEP 2015a, HBEP 2015i, and independent staff analysis
Notes:
[a] Staff measured the diameter of each fan from PTA Figure 2.1-2 General Arrangement/Site Plan (HBEP 2015a).
[b] Staff calculated the exit velocities based on the project owner-provided outlet air flow rates and staff-measured fan diameter from PTA.

Plume Velocity Table 5
Fin Fan Cooler Exhaust Parameters

Parameter	Simple-Cycle Fin Fan Cooler		
Number of Cells (Fans)	28 total, 14 bays (2 fan per bay)		
Cell Height (ft)	24		
Cell Diameter (ft)	13		
Ambient Temperature (ºF)	32	65.8	110
Ambient Relative Humidity	87%	58%	8%
Number in Operation	12 fans	28 fans	28 fans
Outlet Air Temperature (ºF)	70.85	82.2	126.26
Air flow rate/fan (acfm/cell) [a]	222,100*	217,467	238,733
Outlet Air Exit Velocity (ft/s) [a]	27.9*	27.31*	29.98*
Heat Rejection (MW) [a]	33.2*	31.3*	31.3*

Source: HBEP 2015i, HBEP 2016o, and independent staff analysis
Note:
[a] Staff calculated the exit velocities and heat rejection rates based on the air flow rates, inlet and outlet air temperatures from the vendor data sheets (HBEP 2016o), and the cell diameter from Data Responses Set 1 (HBEP 2015i). Staff corrected the 32ºF ambient temperate case exhaust data using mass and energy balance calculations based on the vendor data supplied by the project owner and the number of fans in operation (12 fans in operation in the 32ºF case rather than 28).

PLUME VELOCITY CALCULATION RESULTS

Using the Spillane Approach, the plume average vertical velocities at different heights above ground were determined by staff for calm conditions for the proposed gas turbines, auxiliary boiler, air-cooled condenser (ACC) and fin fan coolers. Staff evaluated the potential for plume merging using the following stack-to-stack distances: (1) the distance between the two GE 7FA.05 combined-cycle turbine stacks would be about 44 meters (m), (2) the distance between the two GE LMS-100PB simple-cycle turbine stacks would be about 44 m. Plumes begin merging when the radius of each of the two plumes added together equals the distance between the stacks. As a rule of thumb they are considered fully merged when the sum of the plume radii adds to equal twice the distance between stacks.

As explained in the Transportation and Traffic section, a plume average vertical velocity of 4.3 m/s has been determined by staff to be the critical velocity of concern to light aircraft. This is based on the Australian Civil Aviation Safety Authority (CASA) advisory circular (CASA 2003). Vertical velocities below this level are not of concern to light aircraft.

The combined-cycle power block would have two GE 7FA.05 combined-cycle turbine stacks, with a spacing of about 44 meters from each other. When the spacing between the stacks is not large enough to prevent plume merging, the exhaust plumes may spread enough to significantly merge prior to the velocity lowering to vertical velocities below levels of concern. Therefore, staff calculated the plume size and vertical velocities for the single plume without merging (N=1) and two plumes fully merged (N=2). Staff calculated plume average vertical velocities for all four operating cases shown in **Plume Velocity Table 1** for the GE 7FA.05 turbines and determined that the worst-case predicted plume velocities would occur at full load operation without inlet air cooling at the 32°F ambient temperature condition. Staff's calculated worst-case plume average velocity values are provided in **Plume Velocity Table 6**.

The GE 7FA.05 gas turbine plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 810 feet above ground for the single turbine plume (N=1). The plume diameter at this height would be around 62.6 meters, which would be larger than the distance between the two GE7FA.05 gas turbine stacks (44 meters). Therefore the merging of the adjacent turbine plumes should be considered. In the case of two plumes fully merging (N=2), the average velocity is calculated to drop below 4.3 m/s at the height of 1,220 feet above ground.

Plume Velocity Table 6
GE 7FA.05 Turbine Plume Size (m) and Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Diameter (m) [a]	Plume Velocity (m/s) [b]	
		N=1	N=2
300	12.84	8.84	Not Merged
400	22.59	6.46	Not Merged
500	32.35	5.51	Not Merged
600	42.10	4.96	Not Merged
700	51.85	4.59	Not Merged
800	61.61	4.31	Not Merged
900	71.36	4.09	Not Merged
1,000	81.12	3.91	Not Merged
1,100	90.87	3.76	4.47
1,200	100.62	3.63	4.32
1,300	110.38	3.52	4.18
1,400	120.13	3.42	4.06
1,500	129.88	3.33	3.96
1,600	139.64	3.25	3.86
1,700	149.39	3.17	3.77
1,800	159.14	3.11	3.70
1,900	168.90	3.05	3.62
2,000	178.65	2.99	3.55
2,100	188.41	2.94	3.49

Notes:
a – The separation between the two stacks would be about 44 meters and the plumes will begin to merge when the plume diameter is the same as the separation and is assumed to be fully merged when the plume diameter is twice the stack separation.
b – Not Merged means not fully merged.

The simple-cycle power block would have two GE LMS-100PB simple-cycle turbine stacks, with a spacing of about 44 meters from each other. Staff calculated the plume size and vertical velocities for the single plume without merging (N=1) and two plumes fully merged (N=2). Staff calculated plume average vertical velocities for all three operating cases shown in **Plume Velocity Table 2** for the GE LMS-100PB turbines and determined that the worst-case predicted plume velocities would occur at 100 percent load operation without inlet air cooling at the 32°F ambient temperature condition. Staff's calculated worst-case plume average velocity values are provided in **Plume Velocity Table 7**.

The GE LMS-100PB gas turbine plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 1,140 feet above ground for the single turbine plume (N=1). The plume diameter at this height would be around 100.3 meters, which would be larger than the distance between the two GE LMS-100PB gas turbine stacks (44 meters). Therefore the merging of the adjacent turbine plumes should be considered. In the case of two plumes fully merging (N=2), the average velocity is calculated to drop below 4.3 m/s at the height of 1,820 feet above ground.

Plume Velocity Table 7
GE LMS-100PB Turbine Plume Size (m) and Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Diameter (m) [a]	Plume Velocity (m/s) [b]	
		N=1	N=2
300	18.39	7.91	Not Merged
400	28.15	6.68	Not Merged
500	37.90	5.99	Not Merged
600	47.65	5.53	Not Merged
700	57.41	5.18	Not Merged
800	67.16	4.91	Not Merged
900	76.92	4.69	Not Merged
1,000	86.67	4.50	Not Merged
1,100	96.42	4.34	5.16
1,200	106.18	4.20	5.00
1,300	115.93	4.08	4.85
1,400	125.68	3.97	4.72
1,500	135.44	3.87	4.61
1,600	145.19	3.79	4.50
1,700	154.94	3.70	4.40
1,800	164.70	3.63	4.32
1,900	174.45	3.56	4.23
2,000	184.21	3.50	4.16
2,100	193.96	3.44	4.09

Notes:
a – The separation between the two stacks would be about 44 meters and the plumes will begin to merge when the plume diameter is the same as the separation and is assumed to be fully merged when the plume diameter is twice the stack separation.
b – Not Merged means not fully merged.

Staff also calculated plume average vertical velocities for the auxiliary boiler using the operating parameters shown in **Plume Velocity Table 3**. **Plume Velocity Table 8** shows the worst-case plume average velocity values for the auxiliary boiler. The auxiliary boiler plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 130 feet above ground.

Plume Velocity Table 8
Auxiliary Boiler Plume Size (m) and Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Diameter (m)	Plume Velocity (m/s)
100	1.58	9.83
110	2.55	6.38
120	3.53	4.92
130	4.50	4.12
140	5.48	3.63
150	6.45	3.29
160	7.43	3.05
170	8.40	2.86
180	9.38	2.72
190	10.35	2.60
200	11.33	2.49
210	12.31	2.41
220	13.28	2.33
230	14.26	2.27
240	15.23	2.21
250	16.21	2.16
260	17.18	2.11
270	18.16	2.07
280	19.13	2.03
290	20.11	1.99
300	21.08	1.95

Staff calculated plume average vertical velocities for all three operating cases shown in **Plume Velocity Table 4** for the combined-cycle's air-cooled condenser and determined that the worst-case height at which the plume velocities would drop below 4.3 m/s would occur at 32°F ambient temperature condition. Staff assumed that the plumes from all cells in operation would be fully merged. Staff's calculated worst-case plume average velocity values are provided in **Plume Velocity Table 9**. The combined-cycle air-cooled condenser plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 2,200 feet above ground.

Plume Velocity Table 9
Combined-Cycle Air-Cooled Condenser Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Velocity (m/s)
400	7.01
500	6.82
600	6.53
700	6.26
800	6.01
900	5.79
1,000	5.59
1,100	5.42
1,200	5.27
1,300	5.13
1,400	5.00
1,500	4.89
1,600	4.78
1,700	4.69
1,800	4.60
1,900	4.51
2,000	4.44
2,100	4.36
2,200	4.30
2,300	4.23
2,400	4.17
2,500	4.11

Finally, staff calculated plume average vertical velocities for all three operating cases shown in **Plume Velocity Table 5** for the simple-cycle fin fan coolers determined that the worst-case height at which the plume velocities would drop below 4.3 m/s would occur at 110°F ambient temperature condition. Staff assumed that the plumes from all cells in operation would be fully merged. Staff's calculated worst-case plume average velocity values are provided in **Plume Velocity Table 10**. The combined-cycle air-cooled condenser plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 280 feet above ground.

Plume Velocity Table 10
Simple-Cycle Fin Fan Cooler Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Velocity (m/s)
110	9.97
120	9.02
130	8.26
140	7.63
150	7.12
160	6.68
170	6.31
180	5.99
190	5.71
200	5.46
210	5.25
220	5.06
230	4.89
240	4.73
250	4.59
260	4.47
270	4.35
280	4.24
290	4.15
300	4.06

The velocity values listed above in **Plume Velocity Table 6** through **Plume Velocity Table 10** are plume average velocities across the area of the plume. The maximum plume velocity, based on a normal Gaussian distribution, is two times the plume average velocities shown in the tables.

It should be noted that additional thermal plume merging between the gas turbine stacks, the air-cooled condenser, the auxiliary boiler, and the fin fan coolers could occur and increase the plume heights where vertical velocities of 4.3 m/s are exceeded under worst case conditions. The model used for this analysis is not able to add different kinds of thermal plumes together. However, the approach is still conservative given the conservatism built in the model.

WIND SPEED STATISTICS

The Air Quality section of this document uses meteorological data from John Wayne airport station, which is about 6.6 miles northeast of the Amended HBEP site. The wind roses and wind frequency distribution data collected from the John Wayne airport station were considered to be representative for the project site location. The project owner provides the calm wind speed statistics for John Wayne airport station from ground-level meteorological data collected for 2010 through 2014 (HBEP 2015a). Calm winds for the purposes of the reported monitoring station statistics are those hours with average wind speeds below 0.5 m/s. Calm or very low wind speeds can also occur for shorter periods of time within each of the monitored average hourly conditions. However, the shortest time resolution for the available meteorological data is one hour. The annual wind rose data shows calm/low wind speed conditions averaging an hour or longer is 2.8 percent in the site area, or about 245 hours per year.

CONCLUSIONS

The worst case calm wind condition vertical plume average velocities from the proposed GE 7FA.05 combined-cycle turbine stacks are predicted to drop below 4.3 m/s at the height of 1,220 feet assuming two plumes fully merged. The worst case calm wind condition vertical plume average velocities from the proposed GE LMS-100PB turbine stacks are predicted to drop below 4.3 m/s at the height of 1,820 feet assuming two plumes fully merged. The worst case auxiliary boiler plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 130 feet. The worst case air-cooled condenser plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 2,200 feet. The worst case plume average velocity for each of the fin fan coolers is calculated to drop below 4.3 m/s at a height of approximately 280 feet. Thus, the thermal plume from the proposed air-cooled condenser would cause greatest risk to light aircraft.

Also, there is the potential for additional thermal plume merging between the gas turbine stacks and the air-cooled condenser or fin fan coolers that could increase the plume heights where vertical velocities of 4.3 m/s are exceeded under worst case conditions. Calm/low wind speed conditions (wind speeds less than 0.5 m/s) conducive to the formation of worst-case thermal plume velocities would occur on average approximately 2.8 percent of the time.

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CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

FAA 2015 - Federal Aviation Administration Memorandum – Technical Guidance and Assessment Tool for Evaluation of Thermal Plume Impact on Airport Operations (September 24, 2015).

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HBEP 2015i - Data Responses, Set1 (Responses to Data Request 1-74) (TN 206858). Submitted to CEC/Docket Unit on December 7, 2015.

HBEP 2016o - California Energy Commission (TN 210732). Supplemental Information to TN 206858 Re: Fin Fan Cooler Data, dated on March 15, 2016. Submitted to CEC/Docket Unit on March 15, 2016

MITRE 2012 - Expanded Model for Determining the Effects of Vertical Plumes on Aviation Safety, Gouldley, Hopper and Schwalbe, MITRE Product MP 120461, September 2012.

MITRE 2016 - Center for Advanced Aviation System Development [http://www.mitre.org/centers/center-for-advanced-aviation-system-development/who-we-are], website accessed 2-23-2016.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
TRANSMISSION LINE SAFETY AND NUISANCE
Obed Odoemelam, Ph.D.

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) for the licensed Huntington Beach Energy Project (HBEP) proposes project modifications that would not change the Transmission Line Safety and Nuisance (TLSN) conditions of certification as already approved. These certification requirements were intended in the California Energy Commission's (Energy Commission) 2014 Final Decision (Decision) to ensure that any transmission line safety and nuisance impacts 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 2014 Decision is necessary for TLSN. The Committee may rely upon the environmental analysis and conclusions of the 2014 Commission Decision regarding TLSN and does not need to re-analyze them. Staff's assessment shows that the proposed design and operational plan would not affect the ability of the Amended HBEP to comply with applicable laws, ordinances, regulations, and standards (LORS) given that the previously-approved conditions of certification would be retained.

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 Public Utilities Commission (CPUC). The owner of the licensed HBEP established the adequacy of their proposed design and operational plan before the Energy Commission which approved the proposal and specified the four conditions of certification necessary. The project owner is proposing the same HBEP compliance measures for the Amended HBEP. Staff has reviewed the related 2014 Decision along with the owner's amendment request documents to determine whether or not the proposed modification would affect the ability of the Amended HBEP to comply with applicable LORS.

SUMMARY OF THE DECISION

In its 2014 Decision (CEC 2014), the California Energy Commission found the design, routing and operational plan for licensed HBEP transmission line to be adequate to ensure operation without adverse safety and nuisance impacts. To ensure implementation of the necessary mitigation measures, the Decision included staff's proposed TLSN conditions of certification **TLSN-1** through **TLSN-4**.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS COMPLIANCE

There have been no changes to the transmission line-related LORS of concern to staff since the Decision was published on October 29, 2014 for the licensed HBEP.

ENVIRONMENTAL IMPACT ANALYSIS

As more fully described in the **PROJECT DESCRIPTION** and **TRANSMISSION SYSTEM ENGINEERING** sections, the Amended HBEP would be located at the site of the licensed HBEP with the generated power transmitted to the region's electric grid using the existing Southern California Edison's (SCE's) 230-kilovolt (kV) switchyard. As with the licensed HBEP, the lines for the Amended HBEP would lie entirely within the boundaries of the existing Huntington Beach Generating Station and no offsite line would be necessary. The applicant has provided the proposed support tower design as necessary for compliance with the National Electrical Safety Code, CPUC's General Order 95 (GO-95) and other applicable safety requirements.

COMPLIANCE WITH LORS

As discussed in staff's analysis for the licensed HBEP, 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 utility in this case is the SCE. Since the proposed HBEP line would be designed according to the respective requirements of GO-95, GO-52, GO-128, GO-131-D, and Title 8, Section 2700 et seq. of the California Code of Regulations, and operated and maintained according to current SCE guidelines, staff considers the proposed design and operational plan to be in compliance with the applicable LORS.

CONCLUSIONS AND RECOMMENDATIONS

The project owner proposes to implement the same design, operational and routing plan approved in the Commission's 2014 Decision on HBEP along with the four implementing conditions of certification. Since the related mitigation requirements would be adequate to minimize the safety and nuisance impacts of specific concern to staff, we conclude that the proposed modification would not affect HBEP's ability to comply with the applicable transmission line safety and nuisance LORS.

CONDITIONS OF CERTIFICATION

Since the Amended HBEP transmission line design and operational plan would ensure compliance with applicable safety and nuisance LORS by retaining the conditions of certification already required for the licensed HBEP, staff does not propose further mitigation. These conditions of certification are presented below for information purposes.

TLSN-1 The project owner shall construct the proposed 230-kV transmission line according to the requirements of California Public Utility Commission's GO-95, GO-52, GO-131-D, Title 8, and Group 2, High Voltage Electrical Safety Orders, sections 2700 through 2974 of the California Code of Regulations, and Southern California Edison's EMF Reduction Guidelines for Electrical Facilities.

Verification: At least 30 days prior to start of construction of the transmission line or related structures and facilities, the project owner shall submit to the compliance project manager (CPM) a letter signed by a California registered electrical engineer affirming that the lines will be constructed according to the requirements stated in the condition.

TLSN-2 The project owner shall measure the strengths of the electric and magnetic fields from the line at the points of maximum intensity at the edge of the right-of-way to validate the estimates provided by the applicant for these fields. These measurements shall be made (a) according to the standard procedures of the American National Standard Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) and, (b) before and after energization. These measurements shall be completed no later than six months after the start of operations.

Verification: The project owner shall file copies of the pre-and post-energization measurements with the CPM within 60 days after completion of the measurements. The CPM shall determine the need for further mitigation from these field measurements.

TLSN-3 The project owner shall ensure that the route of the proposed transmission line is kept free of combustible material, as required under the provisions of GO-95 and California Code of Regulations, title 14, section 1250.

Verification: During the first five (5) years of plant operation, the project owner shall provide a summary of inspection results and any fire prevention activities carried out along the proposed route and provide such summaries in the Annual Compliance Report on transmission line safety and nuisance-related requirements.

TLSN-4 The project owner shall ensure that all permanent metallic objects within the proposed route are grounded according to industry standards.

Verification: At least 30 days before the lines are energized, the project owner shall transmit to the CPM a letter confirming compliance with this condition.

REFERENCES

AES Southland Development LLC. Petition to Amend (PTA) Huntington Beach Energy Project: Dated September 4, 2015

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

CEC 2014d - California Energy Commission. Huntington Beach Power Project: Final Staff Assessment . May 2014.

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CEC 2011b - California Energy Commission. Final Commission Decision: Palmdale Hybrid Power Project. Docketed on 8/15/2011.

CEC 2014d - Final Staff Assessment (TN 202405). Submitted to CEC/ Docket Unit June 2, 2014.

CEC 2014 - California Energy Commission. Huntington Beach Power Project: Final Staff Assessment . May 2014.

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

CEC 2014a - California Energy Commission. Final Commission Decision, Huntington Beach Energy Project . Docketed on 11/4/2014.

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HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
VISUAL RESOURCES
Jeanine Hinde

SUMMARY OF CONCLUSIONS

Staff reviewed potential visual resources impacts previously analyzed for the Huntington Beach Energy Project (HBEP). Because the amended HBEP would change the types, sizes, and massing of power plant structures on the site, staff evaluated how those changes could affect views of the project site for the key observation points (KOPs) closest to the project site. Staff concludes that the amended HBEP would not result in new significant adverse impacts on visual resources or increase the severity of previously identified significant effects. The amended HBEP would not cause any inconsistencies with visual resources laws, ordinances, regulations, and standards (LORS) identified in the Energy Commission's Final Decision (Decision) (Energy Commission 2014a). The amended HBEP does not change the "Findings of Fact" or "Conclusions of Law" for visual resources that are contained in the Decision.

INTRODUCTION

Staff reviewed the visual resources analysis contained in the project owner's Petition to Amend the HBEP (AES 2015a) and compared the potential visual impacts of the amended HBEP to those of the licensed HBEP.

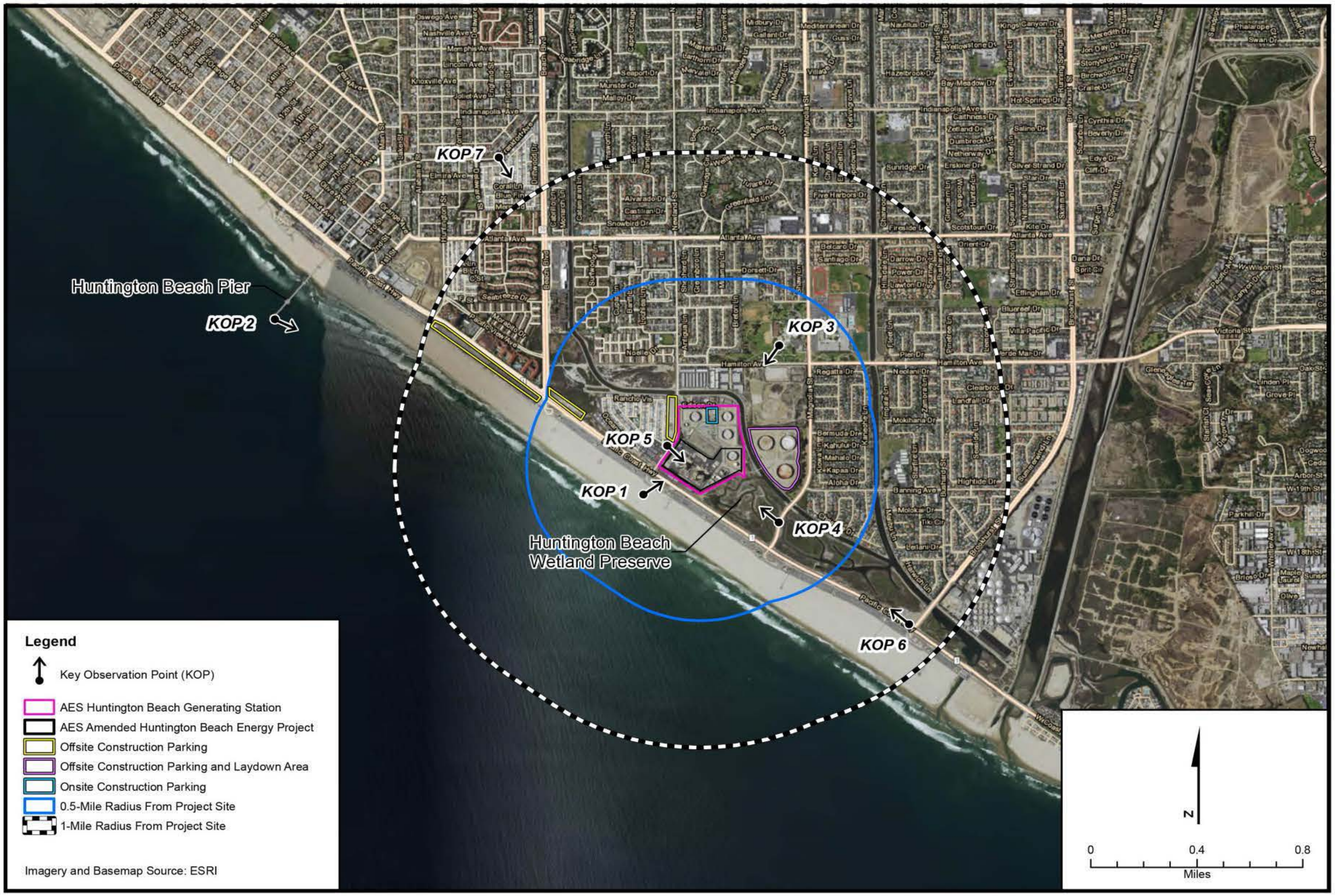
KEY OBSERVATION POINTS

The visual analysis for the licensed HBEP involved identifying KOPs that would most clearly show the visual effects of the proposed project. A total of seven KOPs were selected to represent views from areas with relatively high levels of visual sensitivity. The KOPs represent viewing conditions for nearby residential areas, designated scenic roadways, and visitor and recreation areas. These are the seven KOPs in the visual resources analysis, which are carried forward to staff's analysis of the amended project (see **Visual Resources (VR) Figure 1**):

- **KOP 1** – View from Huntington State Beach
- **KOP 2** – View from the Huntington Beach Municipal Pier
- **KOP 3** – View from Edison Community Park
- **KOP 4** – View from Magnolia Street near the Pacific Coast Highway
- **KOP 5** – View from the Driveway Entrance to the Huntington By-The-Sea Mobile Estates and RV Park
- **KOP 6** – View from the Pacific Coast Highway near Brookhurst Street
- **KOP 7** – View from the Southern Bluff of the Huntington Beach Mesa

VISUAL RESOURCES - FIGURE 1

Amended Huntington Beach Energy Project - Project Site and Key Observation Points



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: AES 2015a

ARCHITECTURAL ENHANCEMENT CONCEPT FOR THE PROJECT SITE

In April 2014, during the original proceeding for the HBEP, the city of Huntington Beach (City) adopted Resolution No. 2014-18 supporting the applicant's conceptual architectural enhancements for the project (City of Huntington Beach 2014). Resolution No. 2014-18 included a recommendation that the Energy Commission incorporate the architectural enhancement concept, with modifications, into final project approvals. The visual resources analysis for the licensed HBEP used the recommended concept for architectural enhancements to assess impacts on visual resources from the KOPs closest to the project site (KOPs 1, 4, and 5). The simulations showing the concept for architectural screening are included in the Energy Commission's Final Decision (Decision), which discusses how the proposed architectural screening would contribute to reducing the project's visual impacts (Energy Commission 2014a). In its Decision, the Energy Commission specified that visual enhancements were to be consistent with the architectural treatment recommended for approval by the City.

The amended HBEP would change the types, sizes, and massing of power plant structures on the site. Consequently, the petitioner developed and presented some revised architectural screening concepts for review and consideration by staff in the City's Planning Division. The petitioner also submitted an application to the City's Design Review Board with the visual enhancement concept that was the product of the coordination process with City planning staff. The City is following a similar process as before, and on March 10, 2016, the Design Review Board took action on the application and issued a recommendation for approval to the City Council as submitted. In its Notice of Action on the proposed visual enhancements, the Design Review Board states that the conceptual plan "should not be construed as a precise plan, reflecting conformance to all Zoning and Subdivision Ordinance requirements." It also states that additional requirements may be imposed before the project starts. An attachment to the Notice of Action includes a condition of approval requiring the project owner to design the visual screening to withstand the elements of the coastal environment and maintain the structures continuously. On March 16, 2016, the petitioner submitted a status update to the Energy Commission on the visual enhancement concept for the amended project, which included the Design Review Board's recommendation and simulated images showing the revised visual enhancement concept (AES 2016).

City planning staff presented the visual enhancement concept for consideration at a City Council study session on April 18, 2016. On May 2, 2016, the City Council voted to adopt Resolution No. 2016-27 in support of the proposed architectural improvements consisting of a marine inspired sphere wall design treatment. As of publication of this Preliminary Staff Assessment, an executed copy of the City's modified and approved resolution has not been forwarded to the Energy Commission for docketing under this proceeding.

The simulated images show three wave-like screens using 24-inch plastic spheres in shades of blue attached to high tensile vertical wires (see the subsection below, "Visual Change for the KOPs," with references to figures at the end of this analysis showing the modified visual screening concept). As described by the project owner, the sphere wall structures will stand approximately 120 feet tall at their highest points. Resolution No. 2016-27 includes a recommendation that the Energy Commission incorporate the architectural treatments into its final project approvals.

During comments and questions offered at the May 2 City Council meeting, Council member Jill Hardy asked about the potential effects of glare from the screening wall spheres. The Decision for the HBEP imposed condition of certification **VIS-1**, which requires that surface treatments minimize the potential visual effects of glare from project surfaces. **VIS-1** also requires the project owner to submit samples of colors and finishes for architectural screening structures for review and approval by the Energy Commission compliance project manager; staff proposes to add a requirement for a physical sample of a plastic sphere like those that will be installed on the screening wall (see the subsection below, "Proposed Modifications to conditions of certification"). These submittals will allow staff to assess the project's compliance with **VIS-1**.

SUMMARY OF THE DECISION

The Decision for the HBEP was published in November 2014. The Decision describes the architectural screening concept that was adopted by the City under its previous Resolution No. 2014-18. The Energy Commission imposed condition of certification **VIS-1**, which requires preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures that was to be consistent with the City's recommended visual screening concept.

The Decision describes the project's operational impacts and visual effects for each of the project's KOPs. For KOP 1 from Huntington State Beach and KOP 3 from Edison Community Park, the Energy Commission concludes that although the impacts at those KOPs are considered less than significant, implementation of condition of certification **VIS-1** could reduce perceived visual changes between the existing power plant (Huntington Beach Generating Station) and the HBEP. The Decision includes a figure showing the conceptual architectural enhancements from the KOP 1 viewpoint (Energy Commission 2014a).

For KOP 4 from Magnolia Street near the Pacific Coast Highway (PCH), the Decision concludes that implementation of the HBEP with no visual screening would substantially degrade the existing visual character of the site and its surroundings. The Energy Commission imposed condition of certification **VIS-1**, and the Decision includes a figure showing the conceptual architectural enhancements from the KOP 4 viewpoint. The Energy Commission adopted condition of certification V**IS-2**, which requires preparation and implementation of a Perimeter Screening and On-site Landscape and Irrigation Plan to further mitigate the visual impact at KOP 4 (Energy Commission 2014a). With implementation of conditions of certification **VIS-1** and **VIS-2**, the Energy Commission concludes in the Decision that visual impacts at KOP 4 would be reduced to less than significant.

For KOP 5 from the entrance to the Huntington By-The-Sea Mobile Estates and RV Park, the Energy Commission concludes that implementation of the HBEP with no surface treatments or visual screening would cause a significant impact on visual resources. With adoption of conditions of certification **VIS-1** and **VIS-2**, the Energy Commission concludes that the visual impact at KOP 5 would be reduced to less than significant. The Decision includes a figure showing the conceptual architectural enhancements from the KOP 5 viewpoint (Energy Commission 2014a).

The Decision discusses the potential for visual impacts to occur during project demolition and construction. The Energy Commission adopted conditions of certification **VIS-3** and **VIS-4** to screen construction sites, protect existing landscape plantings, and implement appropriate construction lighting to reduce those impacts to less than significant (Energy Commission 2014a).

For KOPs 2, 6, and 7, the Energy Commission concludes that potential impacts on visual resources are considered less than significant with no mitigation required (Energy Commission 2014a).

For potential visual impacts of light or glare during project operations, the Energy Commission adopted conditions of certification **VIS-5** and **VIS-6** that require preparation and implementation of a Lighting Management Plan and related documentation. The Energy Commission concludes that with implementation of the adopted visual resources conditions of certification, “the project will meet all applicable [laws, ordinances, regulations, and standards] LORS relating to visual resources which are contained in this Decision” (Energy Commission 2014a).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS COMPLIANCE

An assessment of the project’s consistency with applicable LORS is presented in the **VISUAL RESOURCES** section of the Decision (Energy Commission 2014a). Staff concludes that no changes or updates to the previous list of applicable LORS are necessary. The table in the Decision, “Proposed Project Consistency with Applicable Visual Resources LORS,” includes a comprehensive list of visual resources LORS that also apply to the amended project.

Staff has identified some minor corrections needed to the LORS consistency table under the column, “Basis for Determination.” In **Visual Resources Table 1**, below, these modifications are shown in ~~strike-through~~ for deletions and **<u>bold and underline</u>** for additions. The edits to the table were made primarily to update the City’s resolution number supporting the petitioner’s conceptual architectural improvements. Although few changes were made to the LORS table published in the Decision, it is entirely reproduced below for clarity.

Visual Resources Table 1
Amended Project Consistency with Applicable Visual Resources LORS

LORS Summary Description	Consistency Determination	Basis for Determination
California Coastal Act of 1976		
Section 30251 Scenic and visual qualities. The scenic and visual qualities of coastal areas shall be considered and protected. Permitted development shall be visually compatible with the character of the area and, where feasible, to restore and enhance visual quality in visually degraded areas.	Consistent, with implementation of **VIS-1** and **VIS-2**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the city of Huntington Beach (City), and timely comments from that agency will be considered by the Energy Commission Compliance Project Manager (CPM) prior to plan approval.
City of Huntington Beach General Plan		
Land Use Element (City of Huntington Beach 2013b)		
Goal LU 4. Achieve and maintain high quality architecture and landscapes. **Objective LU 4.1** and **Policies 4.1.2, 4.1.3,** and **4.1.4.** Promote development of public buildings and sites that convey a high quality visual image. Prepare and submit a landscape plan for development projects subject to discretionary review.	Consistent, with implementation of **VIS-1** and **VIS-2**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.
Goal LU 13. Achieve development of a mix of uses that support the needs of the City's residents. **Policy LU 13.1.8**. Ensure that public buildings, sites, and infrastructure improvements are compatible in scale, mass, character, and architecture with existing buildings and characteristics prescribed for the district in which they are located.	Refer to the analyses (below) under the goals, policies, and objectives for the Urban Design Element.	The existing HBGS is in the "Edison & Sanitation District" described in the *Urban Design Guidelines* (City of Huntington Beach 2000). Compliance with the goals, policies, and objectives listed below for the Urban Design Element would achieve consistency with the general guidelines for land uses in the district.
Urban Design Element (City of Huntington Beach 1996)		
Goal UD 1. Enhance the visual image of the City of Huntington Beach. **Policy UD 1.2.1**. Require public improvements to enhance the existing setting for all key nodes, and incorporate landscaping to mask major utilities, such as the Edison generating station.	Consistent, with implementation of **VIS-1** and **VIS-2**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.
Goal UD 2. Protect and enhance public coastal views and oceanside character and screen uses that detract from the City's character. **Objective UD 2.1** and **Policy 2.1.1**. Minimize visual impacts of development on public views to the coastal corridor. Require new development be designed to consider coastal views in its massing, height, and site orientation.	Consistent, with implementation of **VIS-1** and **VIS-2**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.

LORS Summary Description	Consistency Determination	Basis for Determination
Objective UD 2.2 and **Policies 2.2.1, 2.2.4,** and **2.2.5**. Minimize visual impacts of utilities where they are incompatible with surrounding uses by requiring landscape and architectural buffers and screens. Require the review of new or expanded existing utility facilities to ensure no visual impairment of coastal corridors and entry nodes.[1]		
Circulation Element (City of Huntington Beach 2013a)		
Goal CE 8. Maintain and enhance visual quality and scenic views along designated scenic corridors. **Policy 8.1**. Protect and enhance viewsheds along designated scenic corridors. **Policy 8.7**. Require development projects adjacent to a designated scenic corridor to include landscape areas that enhance the corridor and create a buffer between the building site and the roadway. **Policy 8.11**. To the greatest extent possible, locate new and relocated utilities underground within scenic corridors. All other utility features shall be placed and screened to minimize visibility.	Consistent, with implementation of **VIS-1, VIS-2,** and **VIS-3**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval. **VIS-3** will contribute to achieving consistency during long-term project construction.
Utilities Element (City of Huntington Beach 2010b)		
Goal U 5. Maintain and expand service provision to City residences and businesses. **Policy U 5.1.4**. Require the review and or expansions of existing utility facilities to ensure that such facilities will not visually impair the City's coastal corridors and entry nodes.	Consistent, with implementation of **VIS-1, VIS-2,** and **VIS-3**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval. **VIS-3** will contribute to achieving consistency during long-term project construction.
Environmental Resources / Conservation Element (City of Huntington Beach 2004)		
Goal ERC 4. Maintain the visual quality of the City's natural environment. **Objective ERC 4.1** and **Policy 4.1.5**. Enhance and preserve the City's aesthetic resources, including natural areas, beaches, bluffs, and significant public views.	Consistent, with implementation of **VIS-1** and **VIS-2**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.

[1] A "node" is defined as a significant focal point, such as a street intersection that acts as a center of movement and activity. The City identifies primary and secondary entry nodes; Magnolia Street and Newland Street are designated as primary and secondary entry nodes, respectively, where they intersect with the PCH.

LORS Summary Description	Consistency Determination	Basis for Determination
Goal ERC 5 – Conserve the natural environment and resources of the community for the long-term benefit and enjoyment of its residents and visitors. **Policy ERC 5.2.3**. Require that energy saving designs and materials be incorporated into the construction of all public buildings, and encourage their use City-wide.	Consistent, with implementation of **VIS-5** and **VIS-6**	**VIS-5** and **VIS-6** require new lighting fixtures to achieve high energy efficiency for the **amended** HBEP. **VIS-5** and **VIS-6** require the direct involvement of a certified lighting professional trained to integrate efficient technologies and designs into lighting systems.
Coastal Element (City of Huntington Beach 2011)		
Goal C 4. Preserve, enhance, and restore the aesthetic resources of the coastal zone, including natural areas, beaches, bluffs, and significant public views. **Objective C 4.1** and **Policies 4.1.1** and **4.1.4**. Scenic and visual qualities of the coastal area shall be considered and protected as resources of public importance. Development shall be sited and designed to protect public views along the ocean and scenic coastal areas. Preserve nighttime views by minimizing lighting levels along the shoreline. **Objective C 4.2** and **Policies 4.2.1, 4.2.2**, and **4.2.3**. Protect the Coastal Zone's visual resources through design review and development. Preserve public views to and from the bluffs, provide adequate landscaping, evaluate project design for visual impact and compatibility, and use landscaping to mask the electrical power plant on the PCH. Require massing, height, and orientation of new development to protect public coastal views. Promote preservation of significant public view corridors to the coastal corridor. **Objective C 4.6** and **Policy 4.6.3**. Enhance visual resources of the Coastal Zone by implementing landscape standards. For new redevelopment, require the preservation of existing mature trees or replace trees at a minimum 2:1 ratio. **Objective C 4.7** and **Policies 4.7.1, 4.7.2, 4.7.5,** and **4.7.8**. Improve the appearance of visually degraded areas in the Coastal Zone with landscaping to screen uses that detract from scenic quality, locating utilities underground when possible, reviewing new or expanded utility facilities to avoid visual impairment of coastal corridors and entry nodes, and requiring landscaping and architectural buffers and screens around utilities.	Consistent, with implementation of **VIS-1, VIS-2, VIS-3, VIS-4, VIS-5,** and **VIS-6**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval. **VIS-3** will contribute to achieving consistency during long-term project construction. Preparation and implementation of a Lighting Management Plan (**VIS-5**), which will be submitted to the City for review and comment. **VIS-4** requires project lighting during demolition, construction, and commissioning to minimize potential night lighting impacts. **VIS-6** requires a full review of the approved Lighting Management Plan prior to commercial operation of ~~Power Block 2~~ **the simple-cycle gas turbine units**.
Goal C 8. Accommodate energy facilities and promote beneficial effects while mitigating potentially adverse impacts. **Objective C 8.4** and **Policy 8.4.2**. Encourage the owners of the electrical power plant on the PCH to buffer and screen the power plant from the PCH and Beach Boulevard with landscaping and other means. Require any power plant expansion or alteration proposals to include adequate buffering and screening measures.	Consistent, with implementation of **VIS-1** and **VIS-2**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.

LORS Summary Description	Consistency Determination	Basis for Determination
Huntington Beach Zoning & Subdivision Ordinance		
Title 21 – Base Districts		
Ch. 214, PS Public-Semipublic District; § 214.08 Development Standards. (N) Maximum allowable height of structures in the Coastal Zone shall be reduced to be compatible with the established physical scale of the area and to enhance public visual resources.	Consistent, with implementation of **VIS-1**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**). The plan will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval. The consistency determination is also based on the City's approval of Resolution No. ~~2014-18~~ **2016-27** ~~(TN #202084)~~ supporting the ~~applicant's~~ **project owner's** conceptual architectural improvements as modified and the approximately ~~125~~ **150**-foot-high structures for the project.
Title 22 – Overlay Districts		
Ch. 221, Coastal Zone Overlay District; § 221.10 Requirements for New Development Adjacent to Resource Protection Area. Development adjacent to any wetland or land zoned Coastal Conservation requires a landscape plan that prohibits planting of invasive plants, encourages low water use, and uses plants that are native to coastal Orange County. Reduce impacts of walls or barriers adjacent to conservation areas by using open fencing/wall designs, landscape screening, or other features. Walls and fences shall use designs to prevent bird strike hazards (e.g., wood, wrought iron, partially-frosted glass).	Consistent, with implementation of **VIS-2**	Preparation and implementation of a Perimeter Screening and On-site Landscape and Irrigation Plan consistent with the requirements of **VIS-2**. The plan will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval. ~~**VIS-2** requires the project owner to request comments on proposed plant species from the Huntington Beach Wetlands Conservancy.~~
Ch. 221, Coastal Zone Overlay District; § 221.14 Preservation of Visual Resources. Applicants proposing new development shall provide the Director with an evaluation of the project's visual impact. Preservation of public views is required, including views to and from the bluffs, to the shoreline and ocean, and to the wetlands. Preservation of existing mature trees is required to the maximum extent feasible.	Consistency with the requirement to evaluate the visual effects of the proposed project is achieved with preparation of this analysis. Consistency with the requirement to preserve visual resources is achieved with implementation of **VIS-1** and **VIS-2**.	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.

LORS Summary Description	Consistency Determination	Basis for Determination
Ch. 221, Coastal Zone Overlay District; § 221.28 Maximum Height. All rooftop mechanical devices, except for solar panels, shall be set back and screened so that they are not visible.	Consistent, with implementation of **VIS-1**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures consistent with the requirements of **VIS-1**. The plan will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval. The consistency determination is also based on the City's approved Resolution No. ~~2014-18~~ **2016-27** ~~(TN #202084)~~ supporting the ~~applicant's~~ **project owner's** conceptual architectural improvements as modified and the approximately ~~125~~ **150**-foot-high structures for the project.
Title 23 – Provisions Applying in All or Several Districts		
Ch. 230, Site Standards; § 230.76 Screening of Mechanical Equipment. Exterior mechanical equipment shall be screened from view on all sides. Screening of the top of equipment may be required by the Director, if necessary to protect views from an R or OS district. A mechanical equipment plan shall be submitted to the Director to ensure that the mechanical equipment is not visible from a street or adjoining lot.	Consistent, with implementation of **VIS-1**	The "Huntington By-The-Sea Mobile Estates and RV Park" on Newland Street adjacent to the HBEP site is in an "R" district; the zoning district is RMP – Residential Manufactured Home Park. Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures consistent with the requirements of **VIS-1**. The plan will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval. The consistency determination is also based on the City's approved Resolution No. ~~2014-18~~ **2016-27** ~~(TN #202084)~~ supporting the ~~applicant's~~ **project owner's** conceptual architectural improvements as modified and the approximately ~~125~~ **150**-foot-high structures for the project.
Ch. 231, Off-Street Parking and Loading Provisions; § 231.18 Design Standards. Parking area lighting shall be energy efficient and designed to prevent glare on adjacent residences. Security lighting shall be provided in public areas and shall be on a time clock or photo sensor system.	Consistent, with implementation of **VIS-4, VIS-5,** and **VIS-6**	Preparation and implementation of a Lighting Management Plan (**VIS-5**), which will be submitted to the City for timely review and comment. **VIS-4** requires project lighting during demolition, construction, and commissioning to minimize potential night lighting impacts. **VIS-6** requires a full review of the approved Lighting Management Plan prior to commercial operation of ~~Power Block 2~~ **the simple-cycle gas turbine units**. **VIS-5** and **VIS-6** require new lighting fixtures to achieve high energy efficiency for the **amended** HBEP.

LORS Summary Description	Consistency Determination	Basis for Determination
Ch. 232, Landscape Improvements; § 232.02 Applicability. Minimum required site landscaping and planting areas shall be installed and maintained in accord with the standards and requirements of this chapter, including all nonresidential projects.	Consistent, with implementation of **VIS-2**	Preparation and implementation of a Perimeter Screening and On-site Landscape and Irrigation Plant consistent with the requirements of **VIS-2**. The plan will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.
Ch. 232, Landscape Improvements. **Section 232.04 General Requirements**. Landscape plans prepared by a California State Licensed Landscape Architect shall be submitted for approval to the Public Works and Community Development Departments. Significant changes to approved plans require written approval by City staff and/or officials and the landscape designer. Compliance with the Arboricultural and Landscape Standards and Specifications on file in the Public Works Department is required. **Section 232.06 Materials**. Plans shall be harmonious with the architecture and show a recognizable pattern or theme for the overall development. Plants shall be selected for drought tolerance and adaptability to the Huntington Beach environment. Irrigation systems must follow the water efficient landscape requirements of Chapter 14.52 and the Arboricultural Standards and Specifications on file in the Department of Public Works. **Section 232.08 Design Standards**. A minimum of 8 percent of the total net site areas shall be landscaped, or as required by Title 21 or conditions of approval. **Section 232.10 Irrigation**. All landscaped areas shall have a permanent underground, automated irrigation system to promote healthy plant life.	Consistent, with implementation of **VIS-2**	Preparation and implementation of a Perimeter Screening and On-site Landscape and Irrigation Plan consistent with the requirements of **VIS-2**. The plan will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.
Title 24 – Administration		
Ch. 244, Design Review. **Section 244.02 Applicability**. Design review is required for all projects pursuant to any other provision of this Zoning and Subdivision Ordinance and for all projects located within redevelopment areas, specific plans as applicable, areas designated by the City Council, City facilities or projects abutting or adjoining City facilities, projects in or abutting or adjoining OS-PR and OS-S districts, and General Plan primary and secondary entry nodes.	Consistent, with implementation of **VIS-1** and **VIS-2**	Preparation and implementation of a Visual Screening and Enhancement Plan for Project Structures (**VIS-1**) and a Perimeter Screening and On-site Landscape and Irrigation Plan (**VIS-2**). Both plans will be submitted to the City, and timely comments from that agency will be considered by the Energy Commission CPM prior to plan approval.

LORS Summary Description	Consistency Determination	Basis for Determination
Section 244.06 Scope of Review. Specifies that the Board shall consider the arrangement and relationship of proposed structures to one another and to other development in the area. Requires the Board to assess the compatibility in scale and aesthetic treatment of the structures with public district areas. The adequacy of proposed landscaping shall be assessed. The Board shall assess whether energy conservation measures have been proposed and the adequacy of such measures. **Section 244.08 Required Plans and Materials**. Plans and materials to fully describe and explain the proposed development shall be submitted as required by the application form or by the Director, as deemed necessary.		

ENVIRONMENTAL IMPACT ANALYSIS

Staff compared the amended HBEP's visual impacts to the licensed HBEP by evaluating proposed changes to the locations, dimensions, and massing of power plant structures.

MAJOR COMPONENTS OF THE AMENDED HBEP

VR Table 1 compares the dimensions of structures for the licensed HBEP's Power Block 1 to the same or similar structures for the amended HBEP's General Electric (GE) Frame 7FA.05 combined-cycle units. Project features are included on the northeast and east portions of the project site that would likely be visible from publicly accessible areas.

Compared to the licensed HBEP, the amended project's air cooled condenser (ACC) would be twice as long as the ACC unit for the licensed HBEP. The amended HBEP's ACC would also be a few feet taller and wider. The licensed project's three exhaust stacks were 120 feet tall and 18 feet in diameter whereas the amended HBEP's exhaust stacks would be 150 feet tall and 20 feet in diameter. Under the amended HBEP, the exhaust stacks would be more prominent in views from recreational and residential areas and local roadways in the project vicinity, including the PCH.

Compared to the licensed HBEP's three heat recovery steam generators (HRSGs), the amended project's two HRSGs would each be larger in general and considerably longer.

The amended HBEP would include construction of two 50-foot-tall sound/acoustical walls on the northeast portion of the site. The longest segment would stretch along the east/northeast side of the site adjacent to Magnolia Marsh. No similar walls were proposed under the original HBEP.

Compared to the licensed HBEP's three combustion gas turbine (CGT) air intake systems, the amended project's two CGT system structures would be considerably longer and twice as tall.

Visual Resources Table 1
Comparison of Licensed HBEP Power Block 1 to the Amended Project's Combined-Cycle Units for Visually Prominent Structures

	Licensed HBEP Power Block 1				Amended HBEP GE Frame 7FA.05			
Project Feature (see note)	**Length (feet)**	**Width/ Diameter (feet)**	**Height (feet)**	**Quantity**	**Length (feet)**	**Width/ Diameter (feet)**	**Height (feet)**	**Quantity**
CGT	89	32	34	3	40	18	30	2
CGT Generator Enclosure	16	39	34	3	65	24	30	2
Steam Turbine Generator Enclosure	59	55	40	1	—	—	—	—
HRSG	77	44	92	3	140	32	94	2
Stack	—	18	120	3	—	20	150	2
CGT Air Intake System	40	17	38	3	62	18	75	2
ACC	209	127	104	1	420	128	110	1
Service/Fire Water Tank	—	—	—	—	—	52	40 or 45	1
Demineralized Water Tank	—	—	—	—	—	33	30 or 33	1
Eastern Sound Wall	—	—	—	—	848	2.5	50	1
Western Sound Wall	—	—	—	—	170	2.5	50	1
Transmission Structure	—	—	85–135	3	—	—	Not known	Not known
Transmission Dead-end Structure	—	—	75	3	—	—	Not known	Not known

Source: AES 2015a and 2015b

VR Table 2 compares the dimensions of structures for the licensed HBEP's Power Block 2 to the same or similar structures for the amended HBEP's GE LMS100PB simple-cycle turbines. Project features are included on the west portions of the project site that would likely be visible from publicly accessible areas. The project structures associated with the proposed simple-cycle units are generally smaller in scale compared to the licensed HBEP's structures in the former Power Block 2.

Visual Resources Table 2
Comparison of Licensed HBEP Power Block 2 to the Amended Project's Simple-Cycle Units for Visually Prominent Structures

	Licensed HBEP Power Block 2				Amended HBEP LMS100			
Project Feature	**Length (feet)**	**Width/ Diameter (feet)**	**Height (feet)**	**Quantity**	**Length (feet)**	**Width/ Diameter (feet)**	**Height (feet)**	**Quantity**
CGT	89	32	34	3	40	35	30	2
CGT Generator Enclosure	16	39	34	3	24	20	20	2
Steam Turbine Generator Enclosure	59	55	40	1	—	—	—	—
HRSG (licensed HBEP)	77	44	92	3	—	—	—	—
Exhaust Transition (amended HBEP)	—	—	—	—	45	25	40	2
Stack	—	18	120	3	—	13.5	80	2
CGT Air Intake System	40	17	38	3	50	15	47	2
ACC (licensed HBEP)	209	127	104	1	—	—	—	—
Fin Fan Cooler (amended HBEP	—	—	—	—	110	102	24	2
Transmission Structure	—	—	85–135	2	—	—	Not known	Not known
Transmission Dead-end Structure	—	—	75	3	—	—	75	Not known

Source: AES 2015a and 2015b

Visual Change for the KOPs

KOP 1 represents views of the project site from Huntington State Beach. KOP 1 was used to show the conceptual architectural enhancement proposal that was recommended to the Energy Commission for approval in the original licensing proceeding. **VR Figure 2** shows how the approved architectural design concept from the Decision partially screens views of project structures from KOP 1. **VR Figure 3** shows the petitioner's visual simulation of the amended HBEP from KOP 1 with no visual enhancements or screening. **VR Figure 4** shows the revised visual enhancement concept for the amended project for the view from KOP 1; the simulated view is among those included in the City's May 2, 2016, adoption of Resolution No. 2016-27 recommending the modified visual enhancement concept for the project. The visual enhancement concept uses architectural wave forms to screen views of the major power plant structures.

KOP 4 represents views of the project site from Magnolia Street along the southeast border of Magnolia Marsh near the PCH. **VR Figure 5** shows the approved architectural enhancement concept from the KOP 4 viewpoint as shown in the Decision. Under the amended HBEP, the sizes and massing of structures in the northeast portion of the site would be greater compared to the licensed project and clearly visible from KOP 4. The amended project's ACC for the combined-cycle units would be twice as long as the ACC unit for the licensed HBEP (420 feet compared to 209 feet). The amended HBEP's ACC would be situated closer to the project boundary along Magnolia Marsh. The 50-foot-tall sound wall is visible from KOP 4. **VR Figure 6** shows the petitioner's visual simulation of the amended HBEP from KOP 4 with no architectural enhancements or surface treatments. **VR Figure 7** shows the revised visual enhancement concept for the amended project for the view from KOP 4, which is included in the City's adopted Resolution No. 2016-27 recommending the visual enhancement concept for the project. The architectural wave forms in shades of blue partially screen the mass of major power plant structures from this viewpoint. The architectural screening helps to obscure views of the turbines, the lower portions of the exhaust stacks, and the lower end of the ACC unit that is closest to Magnolia Marsh As depicted in **VR Figure 7**, the color scheme proposed by the project owner for the sphere wall appears to be reproduced on the ACC unit, the sound wall, and the upper portions of the stacks as a coordinating paint scheme.

VISUAL RESOURCES - FIGURE 2

Amended Huntington Beach Energy Project - KOP 1 - City of Huntington Beach Recommended Architectural Improvements for the Licensed HBEP

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Energy Commission 2014a

VISUAL RESOURCES - FIGURE 3
Amended Huntington Beach Energy Project - KOP 1 - Proposed Amended HBEP

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: AES 2015a

VISUAL RESOURCES - FIGURE 4

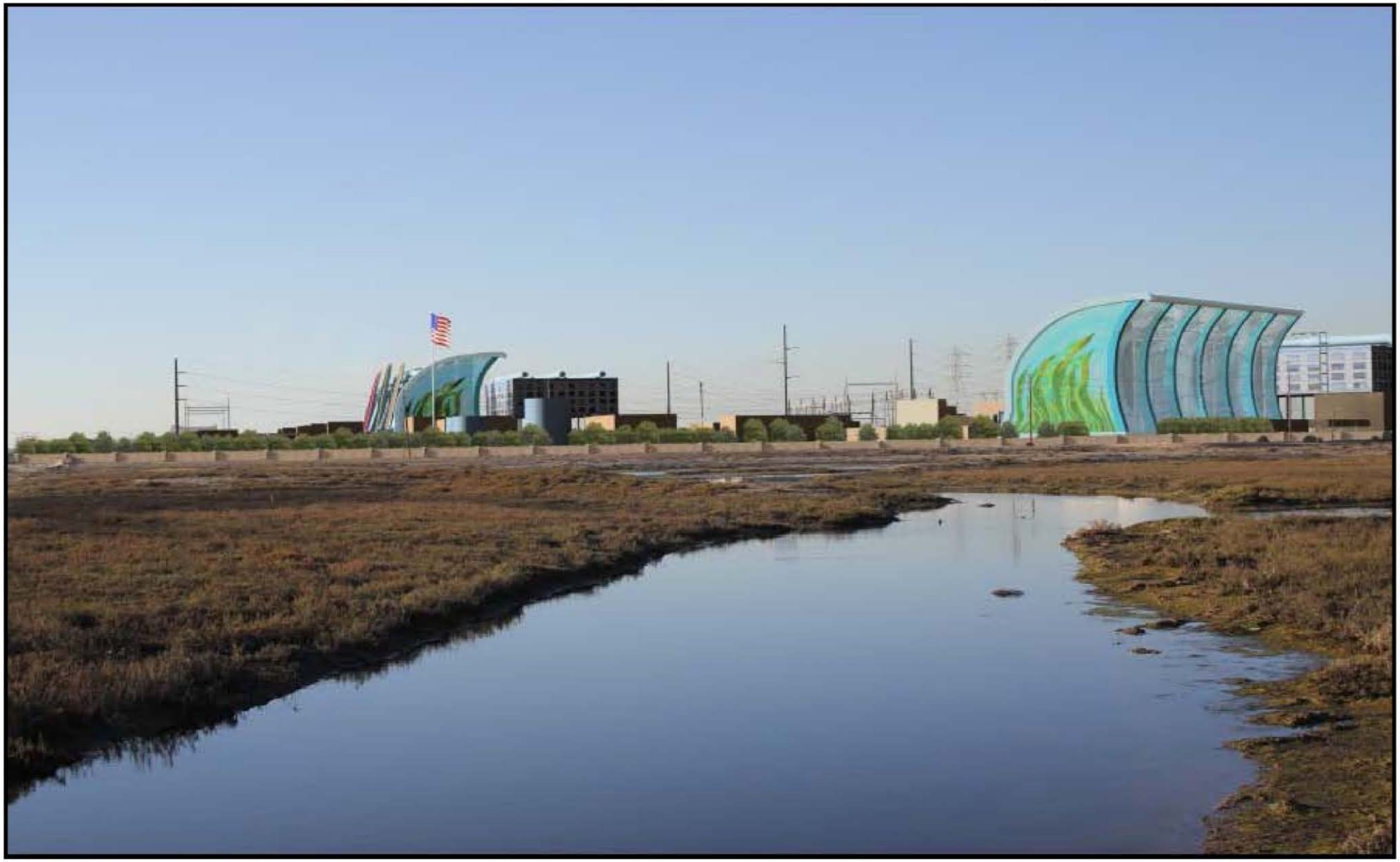
Amended Huntington Beach Energy Project - KOP 1 – Revised Architectural Enhancements Being Considered by the City of Huntington Beach

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: TN #210763

VISUAL RESOURCES - FIGURE 5

Amended Huntington Beach Energy Project - KOP 4 – City of Huntington Beach Recommended Architectural Improvements for the Licensed HBEP



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Energy Commission 2014a

VISUAL RESOURCES - FIGURE 6
Amended Huntington Beach Energy Project - KOP 4 - Proposed Amended HBEP

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: AES 2015b

VISUAL RESOURCES - FIGURE 7

Amended Huntington Beach Energy Project - KOP 4 - Revised Architectural Enhancements Being Considered by the City of Huntington Beach

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: TN #210763

KOP 5 represents views toward the project site from the northwest-west side of the site along Newland Street. This KOP was photographed from inside the driveway entrance to the Huntington By-The-Sea Mobile Estates and RV Park, which is approximately 550 feet inland from the intersection of Newland Street with the PCH (see **VR Figure 1**). **VR Figure 8** shows the approved architectural enhancement concept from the KOP 5 viewpoint as shown in the Decision. The licensed project's ACC unit for the former Power Block 2 is prominently visible on the left side of the visual simulation, and the gas turbine units are screened behind the architectural wave form. The amended HBEP's GE LMS100PB simple-cycle turbines would not require an ACC unit. Under the amended HBEP, the simple-cycle gas turbine units and related structures would be oriented a little differently on the building pad such that a viewer at KOP 5 looking directly toward the site would see little of the power block structures (see **VR Figure 9**).

Under the licensed HBEP, the visual elements associated with the architectural screening concept would have improved the visual character and quality of the KOP 5 view. Staff concludes that the absence of power plant structures, even with visual enhancements, would improve the view compared to the licensed HBEP.

With implementation of an architectural and visual enhancement concept that is substantially consistent with the City's adopted Resolution No. 2016-27, staff concludes that the potentially significant visual impact at KOP 4 is reduced to less than significant. The redesign of the amended HBEP avoids the licensed project's significant visual impact at KOP 5. The visual enhancement concept recommended by the City would achieve compliance with applicable LORS, including the requirement to restore and enhance visual quality in visually degraded areas in coastal areas. For KOPs 2, 3, 6, and 7, staff concludes that potential impacts of the amended HBEP on visual resources are similar to the licensed HBEP and less than significant.

Staff's conclusions for the amended HBEP are consistent with the Energy Commission's assessment and conclusions for visual resources impacts contained in the Decision for the HBEP.

Visible Plumes

Under the original proceeding for the licensed HBEP, Energy Commission air quality staff evaluated the project's exhaust gas characteristics and ambient air conditions and concluded that conditions would be unlikely to cause formation of visible plumes above the project's exhaust stacks (Energy Commission 2014a).

For the amended HBEP, staff concludes that visible water vapor plumes from the proposed GE 7FA.05 turbines/HRSGs and the auxiliary boiler are expected to occur very infrequently, well below 20 percent of seasonal daylight clear hours.

VISUAL RESOURCES - FIGURE 8

Amended Huntington Beach Energy Project - KOP 5 – City of Huntington Beach Recommended Architectural Improvements for the Licensed HBEP

Note:
A print copy with an image width of about 18 1/2 inches and held at a reading distance of approximately 12 inches would approximately represent life-size scale.

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SOURCE: Energy Commission 2014a

VISUAL RESOURCES - FIGURE 9
Amended Huntington Beach Energy Project - KOP 5 - Proposed Amended Project

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SOURCE: AES 2015a

Staff also reviewed the visible plume potential for the GE LMS100PB simple-cycle turbines. Based on data provided by the petitioner, staff concludes there would be no potential for visible water vapor plumes to form above the turbine exhaust stacks. Air quality staff's visible plume analysis is presented in **Appendix VR-1** at the end of this visual resources analysis.

Visual resources staff concludes that no impact on visual resources would occur pertaining to visible water vapor plumes, and no new analysis or changes to the conclusions for the amended HBEP are required.

Cumulative Impacts

The Decision evaluated the impacts of cumulative projects on visual resources for the licensed HBEP (Energy Commission 2014a). The geographic scope of the area that could be subject to a cumulative visual effect is limited to the area near the project site. In the Decision, the cumulative analysis addressed the incremental effects of the HBEP combined with these projects:

- Poseidon Seawater Desalination Project
- Ascon Landfill Remedial Action Plan
- Demolition of Huntington Beach Generating Station (HBGS) Units 3 and 4
- Demolition of the Plains All American Pipeline Tank Farm

Staff has identified no new projects near the site since publication of the Decision; therefore, no new analysis or changes to the cumulative impact conclusions for the amended HBEP are required.

CONCLUSIONS AND RECOMMENDATIONS

KOPs were selected to represent primary viewer groups and sensitive viewing locations in a defined area surrounding the project site where adverse visual impacts could occur (Energy Commission 2014b). The KOPs do not represent the only locations where the project site and structures may be prominently visible. For example, although the amended project's prominent structures would not be prominently visible to a viewer looking directly toward the site from KOP 5, the simple-cycle turbine units would be clearly visible from other nearby viewpoints, including nearby areas along Newland Street and the PCH. The architectural screening concept applies to the amended project as a whole and not only to the representative views provided by the KOPs.

The Decision on the licensed HBEP was based on the City's recommended visual design concept. The City has since completed its review of the petitioner's revised architectural design concept. **VR Figures 4** and **7** are included in this staff assessment to show the revised visual screening concept for the amended project. Staff concludes that with implementation of architectural screening for the project that is consistent with the City's Resolution No. 2016-27 supporting the architectural enhancement concept as modified, the amended HBEP would comply with applicable visual resources LORS. Consistent with the Decision on the licensed project, the potentially significant impact at KOP 4 would be reduced to less than significant. No new significant impacts on visual resources would occur under the amended HBEP.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Staff proposes several modifications to the visual resources conditions of certification published in the Decision for the HBEP (Energy Commission 2014a). These changes are necessary to clarify verification requirements, increase consistency between verification requirements for related conditions of certification, and update content as necessary. A few text changes are recommended to correct mistakes. Modifications are shown in ~~strike-through~~ for deletions and **<u>bold and underline</u>** for additions.

VIS-1 VISUAL SCREENING AND ENHANCEMENT PLAN FOR PROJECT STRUCTURES – PROJECT OPERATION

Prior to **<u>the start of construction</u>** ~~submitting the master drawings and master specifications list for the project to the Chief Building Official (CBO) and the Compliance Project Manager (CPM)~~, the project owner shall prepare and submit a Visual Screening and Enhancement Plan for Project Structures (Plan) that includes methods and materials to visually screen and treat surfaces of publicly visible power plant structures. ~~(Condition of Certification **GEN-2** in the Facility Design section of the Commission Decision addresses requirements pertaining to the master drawings and master specifications list.)~~

The submitted Plan will include evidence of review by a California-licensed structural or civil engineer and an assessment of the feasibility and structural integrity of the architectural and decorative screening elements contained in the Plan. The California-licensed engineer shall review and sign the Plan. Any design changes recommended by the California-licensed engineer to ensure the structural soundness and safety of the project and the architectural design elements shall be incorporated in the Plan before its submittal to the **<u>compliance project manager</u>** **<u>(</u>**CPM**<u>)</u>**.

The project owner shall not submit instructions for architectural screens and other structures and colors and finishes to manufacturers or vendors of project structures, or perform final field treatment on any structures, until written approval of the final Plan is received from the CPM. Modifications to the final Plan shall not occur without the CPM's approval.

The ~~Visual Screening and Enhancement~~ Plan ~~for Project Structures~~ shall be consistent with **Resolution No. 2016-27 adopted by the City of Huntington Beach City Council recommending visual enhancements for the site** ~~Resolution No. 2014-18 adopted by the City of Huntington Beach City Council on April 7, 2014 (TN #202084)~~. Surface treatments for publicly visible power plant structures shall be included in the Plan. Proposed surface treatments shall minimize the potential visual effects of glare from project surfaces. Methods to visually screen and enhance the project site shall visually unify the project to the extent practicable while maintaining compliance with **the** City**'s** **adopted resolution** ~~Resolution No. 2014-18~~.

The **transmission structures** ~~monopoles~~ for the on-site 230-kV transmission line shall have a surface treatment that enables them to blend with the environment to the greatest extent feasible, and the finish shall appear as a matte patina. Unpainted exposed lagging and surfaces of steel structures that are visible to the public shall be embossed or otherwise treated to reduce glare.

The Plan shall meet the following minimum content requirements:

- Inventory of major project structures, **sound/acoustical walls,** and buildings specifying the architectural and decorative screening structures and materials to visually screen and enhance those structures. The inventory shall specify height, length, and width or diameter for each major structure, and scale plans and elevation views shall be included in the Plan with architectural and project structures clearly identified.
- List of colors and finishes that will be applied to architectural screening structures and directly to power plant structures (e.g., paint scheme and finish types for the air cooled condenser**, the exhaust stacks, and the sound wall**). Proposed colors must be identified by vendor, name, and number, or according to a universal designation system.
- Electronic files and a set of print copies of 11-inch by 17-inch (or larger, if necessary) color visual simulations at life-size scale showing the architectural screening structures and surface treatments proposed for the project. Key observation point (KOP) 1, KOP 4, and KOP 5 shall be used to prepare images showing the completed Visual Screening and Enhancement Plan for Project Structures. Colors must be identified by vendor, name, and number, or according to a universal designation system.
- Schedule for completing construction of architectural and decorative screening structures and the surface treatments for publicly visible power plant structures during the construction timeline.
- Procedure and maintenance schedule to ensure that surface treatments and architectural structures are well maintained and consistent with the approved Plan for the life of the project.

Supplement to the Visual Screening and Enhancement Plan for Project Structures. Prior to submitting instructions and orders for architectural screening materials, prefabricated project structures, and paints and other surface treatments to manufacturers or vendors of project structures, the project owner shall submit a Supplement to the Visual Screening and Enhancement Plan for Project Structures (Supplement). The Supplement shall include color brochures, color chips, and/or physical samples showing each proposed color and finish that will be applied to architectural screening structures and directly to power plant structures. <u>**A physical sample of a plastic sphere from the City's recommended sphere wall shall be included with the Supplement.**</u> Electronic files showing proposed colors may not be submitted in place of original samples. Colors must be identified by vendor, name, and number, or according to a universal designation system.

<u>**Verification**</u>**:** <u>**At least**</u> ~~No more than~~ <u>**60**</u> ~~45~~ calendar days <u>**prior to the start of construction**</u> ~~before submitting the master drawings and master specifications list to the CBO (in accordance with the requirements of GEN-2)~~, the project owner shall submit a Visual Screening and Enhancement Plan for Project Structures <u>**(the Plan)**</u> to the CPM for review and approval. The project owner shall, simultaneously with the submission to the CPM, submit seven copies of the ~~Visual Screening and Enhancement~~ Plan to the City of Huntington Beach Planning and Building Department for review and comment.

<u>**A different time frame for submitting the Plan is allowed by agreement between the project owner and the CPM.**</u>

At least 60 calendar days before submitting instructions or orders for architectural screening, prefabricated project structures, and paints and other surface treatment materials, the project owner shall submit a Supplement to the Visual Screening and Enhancement Plan for Project Structures <u>**(Supplement)**</u> ~~simultaneously~~ to the CPM for review and approval. Simultaneously with the submission to the CPM, the project owner shall submit seven copies of the Supplement text and one set of physical samples of paint colors and other surface treatments to the City's Planning and Building Department for review and comment.

If the CPM determines that the Plan and/or its Supplement require revisions, the project owner shall provide an updated version with the specified revision(s) for review and approval by the CPM. Copies of the revised Plan and/or the Supplement (if either is required) shall be provided to the City for review and comment. City staff requires seven copies of the revised Plan or Supplement.

The project owner shall provide the CPM with copies of the transmittal letters submitted to the City requesting timely reviews of the Plan, the Supplement, and any revisions. The City shall be allowed 30 calendar days following receipt of the stated plans to provide comments to the project owner and to the CPM ~~within 30 calendar days of receiving any of the stated plans~~. In the absence of comments within that timeframe, or a request from the City for an extension of time, the CPM may deem the Plan, the Supplement, and any revisions acceptable to the City.

At least 10 calendar days before commercial operation of ~~Power Block 1~~ **<u>the combined-cycle gas turbine (CCGT) units</u>**, the project owner shall notify the CPM in writing with information on 1) the status of implementing the requirements set forth in the Visual Screening and Enhancement Plan for Project Structures and 2) a schedule for completing the remaining Plan requirements during the construction timeline. These steps shall be repeated for commercial operation of ~~Power Block 2~~ **<u>the simple-cycle gas turbine (SCGT) units</u>**.

The project owner shall schedule periodic site visits with the CPM to view progress on implementing the Plan. At a minimum, site visits shall be scheduled within 30 calendar days of commercial operation of ~~Power Block 1~~ **<u>the CCGT units</u>** and again within 30 calendar days of commercial operation of ~~Power Block 2~~ **<u>the SCGT units</u>**. The Plan shall be fully implemented within **<u>180</u>** ~~90~~ calendar days of completing demolition **<u>of the HBGS and construction of the amended HBEP</u>** ~~of the Huntington Beach Generating Station Units 1 and 2~~. The project owner shall verify in writing when the Plan is fully implemented and the facility is ready for inspection. The project owner shall obtain written confirmation from the CPM that the project complies with the Visual Screening and Enhancement Plan for Project Structures.

The project owner shall provide a status report regarding maintenance of the architectural screens and surface treatments in the Annual Compliance Report for the project. At a minimum, the report shall include:

- Descriptions of the condition of the architectural screening structures and treated surfaces of publicly visible structures at the power plant site.
- Descriptions of major maintenance and painting work required to maintain the original condition of architectural screening structures and treated surfaces during the reporting year.
- Electronic photographs showing the results of maintenance and painting work.

VIS-2 PERIMETER SCREENING AND ON-SITE LANDSCAPE AND IRRIGATION PLAN – PROJECT OPERATION

The project owner shall prepare and implement a Perimeter Screening and On-site Landscape and Irrigation Plan (Plan) to screen views of power plant structures. The Plan shall achieve a goal to screen and soften views of the power plant from Magnolia Marsh, the Huntington Beach Wetlands & Wildlife Care Center, the Huntington By-The-Sea Mobile Estates and RV Park, Newland Street, Magnolia Street, and the Pacific Coast Highway.

The Plan shall be prepared with the direct involvement of a licensed professional landscape architect familiar with local growing conditions, suitable native and non-invasive plant species for the project area, and local availability of proposed species. The licensed landscape architect shall review and sign the Plan. Any changes recommended by the licensed landscape architect shall be incorporated in the Perimeter Screening and On-site Landscape and Irrigation Plan *before* its submittal to the CPM for approval. The Perimeter Screening and On-site Landscape and Irrigation Plan shall comply with the landscape and irrigation requirements of the City of Huntington Beach General Plan and the Huntington Beach Zoning & Subdivision Ordinance.

The submitted Plan shall show evidence of participation by a wildlife biologist qualified to comment on tree species proposed for planting adjacent to Magnolia Marsh and confirm that those species will minimize new opportunities for raptors to prey on special-status birds in the marsh.

Design and submittal of the Perimeter Screening and On-site Landscape and Irrigation Plan shall occur *after* completion of the project's final general arrangement/site plan to accurately show interior area constraints (e.g., paved interior site access and emergency response roads).

The Perimeter Screening and On-site Landscape and Irrigation Plan shall include construction of an 8-foot-tall decorative masonry wall to extend along the site boundary adjacent to the Huntington Beach Wetlands & Wildlife Care Center and parking lot and along Magnolia Marsh (i.e., the southwest-west and southeast-east boundaries). All existing exterior site perimeter chain-link fencing shall be replaced with an 8-foot-tall decorative masonry wall.

The project owner shall not purchase or order plants, landscape and irrigation supplies and materials, or construction materials for the masonry wall until written approval of the final Plan is received from the CPM. Modifications to the final Plan shall not occur without the CPM's approval.

The Perimeter Screening and On-site Landscape and Irrigation Plan shall meet the following minimum requirements:

- o Provide a detailed landscape and irrigation plan at a scale of 1 inch to 40 feet (1:40) (or similar scale) listing proposed plant species, and installation sizes, quantities, and spacing. The plan shall include expected heights at 10 years and maturity and expected growth rates to maturity. To achieve year-round screening, the Plan shall emphasize the use of evergreen species. No new or replacement lawn areas shall be planted anywhere on the site interior.

- Proposed tree species shall be 24-inch box size unless the licensed landscape architect recommends a different size for a species. Except for areas where planting of new or replacement trees at the site periphery is infeasible (based on the final general arrangement/site plan), spacing of trees shall be sufficiently dense to ensure maximum screening by the tree canopy at maturity. Faster-growing tree species shall be included provided that those species are non-invasive and suited to the coastal environment.
- Proposed shrub species shall be selected to achieve maximum screening effectiveness. Shrubs planted inside the 8-foot-tall masonry wall along Magnolia Marsh shall be selected to achieve a mature height of 12 feet to 15 feet, with a goal to increase the effectiveness of visual screening provided by the wall. Shrubs shall be installed at 5-gallon size unless the licensed landscape architect recommends a different size for a species.
- Proposed tree species along the site boundary adjacent to Magnolia Marsh shall be selected with a goal to discourage perching by raptors and minimize predation on special-status birds. Tree species with branch and foliage characteristics that would not be attractive to perching raptors are preferred.
- Provide electronic files and sets of print copies of 11-inch by 17-inch (or larger, if necessary) color visual simulations at life-size scale showing the landscape plantings at the time of installation and 10 years after installation. Key observation point (KOP) 1, KOP 4, and KOP 5 shall be used to prepare the visual simulations.
- Provide discussions of plans and methods to efficiently irrigate landscape plantings to ensure their survival and maintain optimal growth rates.
- Provide a plan view of the project site that clearly shows the planting plan for the site and the existing and new 8-foot-tall decorative masonry walls along the exterior site perimeter. Details on the materials and design of the masonry wall shall be included in the plan.
- Provide a detailed schedule for completing installation of landscape plantings during the project construction schedule and the masonry walls along the site perimeter.
- Provide a procedure for maintaining and monitoring the landscape and irrigation system and replacing all unsuccessful plantings for the life of the project.
- Provide a table summarizing the project’s conformance with the City’s landscape screening and irrigation regulations, including applicable goals, objectives, and policies in the Urban Design Element, Circulation Element, and Coastal Element of the General Plan. The table shall include applicable chapters and sections of the Huntington Beach Zoning & Subdivision Ordinance, as identified in **Visual Resources Appendix-4** of the Final Staff Assessment **<u>for the licensed project</u>**.

Verification: **At least 90 calendar days before the start of site mobilization** ~~No more than 45 calendar days after submitting the master drawings and master specifications list to the CBO (in accordance with the requirements of condition of certification **GEN-2**)~~, the project owner shall submit the Perimeter Screening and On-site Landscape and Irrigation Plan to the CPM for review and approval. The project owner shall, simultaneously with the submission to the CPM, submit seven copies of the Perimeter Screening and On-site Landscape and Irrigation Plan to the City of Huntington Beach Planning and Building Department for review and comment.

If the CPM determines that the Plan requires revision, the project owner shall provide an updated version with the specified revision(s) for review and approval by the CPM. The project owner shall simultaneously with the submission to the CPM submit seven copies of the revised Perimeter Screening and On-site Landscape and Irrigation Plan to the City of Huntington Beach Planning and Building Department for review and comment.

The project owner shall provide the CPM with copies of the transmittal letters submitted to the City requesting review of the Plan and any revisions. The City shall be allowed 30 calendar days following receipt of the stated plans to provide comments to the project owner and to the CPM. In the absence of comments within that timeframe, or a request from the City for an extension of time, the CPM may deem the Plan and any revisions acceptable to the City.

At least 10 calendar days before commercial operation of ~~Power Block 1~~ **the combined-cycle gas turbine (CCGT) units**, the project owner shall notify the CPM in writing with information on 1) the status of implementing the requirements set forth in the Perimeter Screening and On-site Landscape and Irrigation Plan, and 2) a schedule for completing the remaining Plan requirements during the construction timeline. These steps shall be repeated for commercial operation of ~~Power Block 2~~ **the simple-cycle gas turbine (SCGT) units**.

The project owner shall schedule periodic site visits with the CPM to view progress on implementing the Plan. At a minimum, site visits shall be scheduled within 30 calendar days of commercial operation of ~~Power Block 1~~ **the CCGT units** and again within 30 calendar days of commercial operation of ~~Power Block 2~~ **the SCGT units**. The Plan shall be fully implemented **within 180 calendar days of completing demolition of the HBGS and construction of the amended HBEP** ~~no less than 60 days before commercial operation of Power Block #1~~. The project owner shall verify in writing when the Plan is fully implemented and the facility is ready for inspection. The project owner shall obtain written confirmation from the CPM that the project complies with the **Perimeter Screening and On-site Landscape and Irrigation Plan** ~~Visual Screening and Enhancement Plan for Project Structures~~.

The project owner shall provide a status report describing landscape maintenance activities in the Annual Compliance Report for the project. At a minimum, the report shall describe:

- Overall condition of the landscape areas and irrigation system at the power plant site.
- Major activities that occurred during the reporting year, including replacement of dead or dying vegetation.
- Maintenance of the site periphery masonry wall and any other elements included in the plan.

VIS-3 LONG-TERM CONSTRUCTION SCREENING, LANDSCAPE PROTECTION, AND SITE RESTORATION PLAN – PROJECT DEMOLITION, CONSTRUCTION, AND COMMISSIONING

Prior to the start of site mobilization, the project owner shall prepare and implement a Construction Screening, Landscape Protection, and Site Restoration Plan **(Plan)** describing methods and materials that will be used during each project phase to screen project construction and parking areas and views of the project site from areas where construction activities have the potential to be visible during a phase. The ~~Construction Screening, Landscape Protection, and Site Restoration~~ Plan will describe methods and materials to identify and protect existing landscape trees and shrubs. The ~~Construction Screening, Landscape Protection, and Site Restoration~~ Plan will identify existing landscaped areas where plantings will be retained and where they will be permanently removed. The ~~Construction Screening, Landscape Protection, and Site Restoration~~ Plan will include provisions to restore areas where ground disturbance occurred during construction.

To minimize the adverse visual impacts of project construction during each project phase, the project owner shall install and maintain construction screening fencing along the perimeters of the project site areas where there could be views from public use areas of construction activities during a phase. The project owner will consult with the CPM to determine areas where screening fencing is required during a project phase or phases. Depending on the location of on-site construction work, the areas requiring screening include the perimeter of the wetland along the southeast-east site boundary, the west side perimeter of the project site on Newland Street, and the southwest-west perimeter of the site along the Huntington Beach Wetlands Conservancy property. The screening fencing for the power plant site shall be no less than 12 feet tall.

Brightly-colored construction exclusion fencing shall be used on-site to clearly delineate areas where existing landscape plantings will be protected and retained.

Condition of certification **VIS-2** includes construction of an 8-foot-tall decorative masonry wall to extend along the site boundary adjacent to the Huntington Beach Wetlands & Wildlife Care Center and the wetland. Upon commencement of construction of the masonry wall, the CPM shall allow the project owner to remove all construction screening fencing from those portions of the site boundary.

Screening fencing shall be installed to visually screen the open lots that will be used for parking on Newland Street across from the project site and along the Pacific Coast Highway (PCH) at Beach Boulevard. The screening fencing for the parking lots shall be no less than 6 feet tall and shall meet the City of Huntington Beach corner lot visibility requirements specified in Title 23, Chapter 230, "Site Standards," of the Huntington Beach Municipal Code (i.e., 25-foot by 25-foot corner visibility triangle).

The Construction Screening, Landscape Protection, and Site Restoration Plan shall provide color images showing options for site perimeter screening materials. All site perimeter screening fencing and construction exclusion fencing shall be well maintained and repaired or replaced as necessary for the duration of project demolition, construction, and commissioning.

When construction is finished, all evidence of construction activities shall be removed and disturbed areas restored to their original or better condition. The Construction Screening, Landscape Protection, and Site Restoration Plan shall describe the methods and schedule for the restoration work to occur.

The project owner shall not purchase or order any materials for site perimeter screening fencing until written approval of the final Construction Screening, Landscape Protection, and Site Restoration Plan is received from the CPM. Modifications to the Construction Screening, Landscape Protection, and Site Restoration Plan shall not occur without the CPM's approval.

Verification: At least 60 calendar days before the start of site mobilization, the project owner shall submit a Construction Screening, Landscape Protection, and Site Restoration Plan to the CPM for review and approval. Simultaneously with the submission of **the** ~~a Construction Screening, Landscape Protection, and Site Restoration~~ Plan to the CPM, the project owner shall submit seven copies of **the** ~~a Construction Screening, Landscape Protection, and Site Restoration~~ Plan to the City of Huntington Beach Planning and Building Department for review and comment.

If the CPM determines that the Plan requires revision, the project owner shall provide an updated version with the specified revision(s) for review and approval by the CPM. Seven copies of the revised Plan shall be submitted to the City of Huntington Beach Planning and Building Department for review and comment.

The project owner shall provide the CPM with a copy of the transmittal letter submitted to the City requesting review of the Construction Screening, Landscape Protection, and Site Restoration Plan and any revisions. The City shall be allowed 30 calendar days following receipt of the stated plans to provide comments to the project owner and to the CPM. In the absence of comments within that timeframe, or a request from the City for an extension of time, the CPM may deem the Construction Screening, Landscape Protection, and Site Restoration Plan and any revisions acceptable to the City.

Before the start of ground disturbance at the project site, the project owner shall install site perimeter screening fencing and construction exclusion and parking area fencing at the locations agreed upon in consultation with the CPM. The project owner shall notify the CPM within 7 calendar days of installing the fencing that it is ready for inspection.

The project owner shall report any work required to repair or replace temporary screening and construction exclusion fencing in the Monthly Compliance Report for the project.

Within 10 calendar days of receipt of confirmation from the project owner that construction of the permanent 8-foot-tall masonry wall is ready to begin, the CPM shall notify the project owner that construction screening fencing can be removed from the portions of the site boundaries where the masonry wall will be erected.

Within 30 calendar days of completing construction of the HBEP power blocks and buildings, including demolition of HBGS Units 1 and 2, the project owner shall notify the CPM in writing of the status of implementing the requirements set forth in the Construction Screening, Landscape Protection, and Site Restoration Plan. Such notification shall include a schedule for completing the Plan requirements. The Plan shall be fully implemented within 180 calendar days of completing demolition **of the HBGS** and construction **of the amended HBEP**. The project owner shall verify in writing that the Plan is implemented and restored areas are ready for inspection. The project owner shall obtain written confirmation from the CPM that the project complies with the Plan.

VIS-4 LONG-TERM LIGHTING – PROJECT DEMOLITION, CONSTRUCTION, AND COMMISSIONING

Consistent with applicable worker safety regulations, the project owner shall ensure that lighting of on-site construction areas, construction worker parking lots, and construction laydown areas minimizes potential adverse night lighting impacts by implementing the following measures:

- All fixed-position lighting shall be hooded and shielded to direct light downward and toward the construction area to be illuminated to prevent illumination of the night sky and minimize light trespass (i.e., direct light extending beyond the boundaries of the construction worker parking lots and construction sites, including any security-related boundaries).
- Lighting of any tall construction equipment (e.g., scaffolding, derrick cranes, etc.) shall be directed toward areas requiring illumination and shielded to the maximum extent practicable.

- Task-specific lighting shall be used to the maximum extent practicable.
- Wherever and whenever feasible, lighting shall be kept off when not in use and motion sensors shall be used to the maximum extent practicable.
- The Compliance Project Manager (CPM) shall be notified of any construction-related lighting complaints. Complaints shall be documented using a form in the format shown in Attachment 1, and completed forms shall record resolution of each complaint. A copy of each completed complaint form shall be provided to the CPM. Records of lighting complaints shall also be kept in the compliance file at the project site.

Verification: Within 7 calendar days after the first use of fixed-position parking area and construction-related lighting for major HBEP construction milestones, the project owner shall notify the CPM that the lighting is ready for inspection. Verification is to be repeated for these three construction milestones:

- demolition of HBGS Unit 5 and east fuel oil tank and construction of ~~Power Block 1~~ **the combined-cycle gas turbine units**,
- construction of ~~Power Block 2~~ **the simple-cycle gas turbine units**, and
- demolition of HBGS Units 1 and 2 ~~and construction of Buildings 33 and 34~~.

If the CPM determines that modifications to the lighting are needed for any construction milestone, within 14 calendar days of receiving that notification, the project owner shall correct the lighting and notify the CPM that modifications have been completed.

Within 48 hours of receiving a lighting complaint for any construction activity, the project owner shall provide a copy of the complaint report and resolution form to the CPM, including a schedule for implementing corrective measures to resolve the complaint. The project owner shall report any lighting complaints and document their resolution in the Monthly Compliance Report for the project, accompanied by copies of completed complaint report and resolution forms for that month.

VIS-5 LIGHTING MANAGEMENT PLAN – PROJECT OPERATION

Prior to **purchasing lighting equipment for** ~~commercial operation of~~ the HBEP ~~Power Block 1~~ **combined-cycle gas turbine (CCGT) units**, the project owner shall prepare and implement a comprehensive Lighting Management Plan for the HBEP.

Consistent with applicable worker safety regulations, the project owner shall ensure the design, installation, and maintenance of all permanent exterior lighting such that light sources are not directly visible from areas beyond the project site, reflected glare is avoided, and night lighting impacts are minimized or avoided to the maximum extent feasible. All lighting fixtures shall be selected to achieve high energy efficiency for the HBEP facility.

The project owner shall not purchase or order any lighting fixtures or apparatus until written approval of the final plan is received from the Compliance Project Manager (CPM). Modifications to the final Lighting Management Plan shall not occur without the CPM's approval.

The project owner shall meet these requirements for permanent project lighting:

- A Lighting Management Plan shall be prepared that integrates efficient technologies and designs into lighting systems. The plan shall include evidence that a certified lighting professional participated in plan preparation.
- Exterior lights shall be hooded and shielded and directed downward or toward the area to be illuminated to prevent obtrusive spill light (i.e., light trespass) beyond the project site.
- Exterior lighting shall be designed to minimize backscatter to the night sky to the maximum extent feasible.
- Energy efficient lighting products and systems shall be used for all permanent new lighting installations. Smart bi-level exterior lighting using high efficiency directional LED fixtures shall be used as appropriate for exterior installations. The lighting system shall work in conjunction with occupancy sensors, photo sensors, wireless controls, and/or other scheduling or controls technologies to provide adequate light for security and worker safety, and to maximize energy savings.
- **<u>Lighting to enhance the aesthetics of the project's architectural screening structures shall be addressed in the Lighting Management Plan.</u>**
- Lighting fixtures shall be kept in good working order and continuously maintained according to the original design standards.
- The CPM shall be notified of any complaints about permanent lighting at the project site. Complaints shall be documented using a form in the format shown in **Attachment 1**, and completed forms shall record resolution of each complaint. A copy of each completed complaint form shall be provided to the CPM. Records of lighting complaints shall also be kept in the compliance file at the project site.

<u>Verification</u>: At least **<u>90</u>** ~~60~~ calendar days before **<u>purchasing permanent lighting equipment for</u>** ~~commercial operation of Power Block 1~~ **<u>the CCGT units</u>**, the project owner shall submit a comprehensive Lighting Management Plan to the CPM for review and approval. Simultaneously with the submission of the Lighting Management Plan to the CPM, the project owner shall submit seven copies to the City of Huntington Beach Planning and Building Department for review and comment.

If the CPM determines that the Plan requires revision, the project owner shall provide an updated version with the specified revision(s) for review and approval by the CPM. Seven copies of the revised Lighting Management Plan shall be provided to the City of Huntington Beach Planning and Building Department for review and comment.

The project owner shall provide the CPM with a copy of the transmittal letters to the City requesting review of the Lighting Management Plan and any plan revisions. The City shall be allowed 30 calendar days following receipt of the stated plans to provide comments to the project owner and to the CPM. In the absence of comments within that timeframe, or a request from the City for an extension of time, the CPM may deem the Lighting Management Plan and any revisions acceptable to the City.

Prior to the start of commercial operation of ~~Power Block 1~~ **the CCGT units**, the project owner shall notify the CPM in writing that installation of permanent lighting for ~~Power Block 1~~ **those units** has been completed and that the lighting is ready for inspection. If the CPM notifies the project owner that modifications to the lighting system are required, within 30 days of receiving that notification, the project owner shall implement all specified changes and notify the CPM that the modified lighting system(s) is ready for inspection. The project owner shall obtain written confirmation from the CPM that the project complies with the Plan.

Within 48 hours of receiving a complaint about permanent project lighting, the project owner shall provide a copy of the complaint report and resolution form to the CPM, including a schedule for implementing corrective measures to resolve the complaint.

The project owner shall report any complaints about permanent lighting and document their resolution in the Annual Compliance Report for the project, accompanied by copies of completed complaint report and resolution forms for that year.

VIS-6 LIGHTING MANAGEMENT PLAN, REVIEW AND LETTER REPORT – PROJECT OPERATION

Prior to **purchasing lighting equipment for** ~~commercial operation of~~ the HBEP ~~Power Block 2~~ **simple-cycle gas turbine (SCGT) units**, the project owner shall conduct a full review of the approved Lighting Management Plan to determine whether updates to the Plan are needed (e.g., to implement lighting technology changes). Review of the Plan shall include preparation and submittal of a letter report summarizing conclusions and recommendations for the lighting plan. The letter report shall include evidence that a certified lighting professional participated in Plan review.

The project owner shall not purchase or order any permanent lighting for ~~Power Block 2~~ **the SCGT units** or new buildings (including administrative or maintenance buildings or warehouses) until written approval of the final plan is received from the CPM. Modifications to the Lighting Management Plan are prohibited without the CPM’s approval. Installation of lighting must be completed by the start of commercial operation of ~~Power Block 2~~ **the SCGT power block**.

Verification: At least **90** ~~60~~ calendar days before **purchasing permanent lighting equipment for** ~~commercial operation of Power Block 2~~ **the SCGT units**, the project owner shall submit the Plan review and letter report to the CPM for review and approval. Simultaneously with the submission of the Plan review and letter report to the CPM, the project owner shall submit seven copies to the City of Huntington Beach Planning and Building Department for review and comment. ~~The project owner shall provide any comments on the plan received from the City shall be provided to the CPM within 3 business days of receipt.~~

The project owner shall provide the CPM with a copy of the transmittal letter requesting the City's review of the Plan review and letter report**.** The City shall be allowed 30 calendar days following receipt of the stated **P**~~p~~lan~~t~~ to provide comments to the project owner and to the CPM. In the absence of comments within that timeframe, or a request from the City for an extension of time, the CPM may deem the letter report acceptable to the City.

Prior to the start of commercial operation of ~~Power Block 2~~ **the SCGT units**, the project owner shall notify the CPM in writing that installation of permanent lighting has been completed and that the lighting is ready for inspection. If the CPM notifies the project owner that modifications to the lighting system are required, within 30 days of receiving that notification, the project owner shall implement all specified changes and notify the CPM that the modified lighting system(s) is ready for inspection. The project owner shall obtain written confirmation from the CPM that the project complies with the Lighting Management Plan.

REFERENCES

AES 2015a - AES Southland Development, LLC, *Petition to Amend, Huntington Beach Energy Project (12-AFC-02C)*, September 2015. Pages 2-13 and 5.13-1 to 5.13-10. Figures 2.1-2, 2.1-3a to 2.1-3d, and 5.13-1 to 5.13-7. Appendix 5.13A. (TN #206087) Submitted to the Energy Commission by AES Southland Development with technical assistance from CH2MHILL.

AES 2015b - AES Southland Development, LLC, Data Responses, *Set 1A (Response to Data Requests 1 to 74) (12-AFC-02C)*, December 4, 2015. Pages 22 to 23 and 36 to 45 (TN #206858) Submitted to the Energy Commission by AES Southland Development with technical assistance from CH2MHILL.

AES 2016 - AES Southland Development, LLC, Conceptual Design Plan – Status Update. March 16, 2016, letter from Stoel Rives, LLP, Sacramento, CA. transmitting the City of Huntington Beach Design Review Board March 10, 2016, Notice of Action on the Application No. 16-004, AES Energy Project – Visual Screening. (TN #210763).

City of Huntington Beach 2014 - Resolution No. 2014-18. A Resolution of the City Council of City of Huntington Beach Supporting Proposed Architectural Improvements as Modified and Approximate 125-foot-high Structures Related to the Reconstruction of the Huntington Beach Energy Project (11-3122/107796.doc). (TN #202084) Passed and adopted by the City Council of the City of Huntington Beach at a regular meeting thereof held on the 7th day of Apri1, 2014.

Energy Commission 2014a - *Huntington Beach Energy Project, Final Decision*, November 2014. Section E, Visual Resources on pages 6.5-1 to 6.5-32; Visual Resources Figures 1 through 14b; and pages APP-149 to APP-163 (TN #203309) Publication #CEC-800-2014-001-CMF, Docket #12-AFC-02.

Energy Commission 2014b - *Huntington Beach Energy Project, Final Staff Assessment*, May 2014. Pages 4.12-1 to 4.12-64, Figures 1 to 23, Appendices 1 to 4 and Attachment 1 (TN #202405) Publication #CEC-700-2013-002-FSA, Docket #12-AFC-02.

APPENDIX VR-1: PLUME VELOCITY ANALYSIS

Wenjun Qian, Ph.D., P.E.

INTRODUCTION

The following provides the assessment exhaust stack plume vertical velocities of the Amended Huntington Beach Energy Project (Amended HBEP) combustion turbines, auxiliary boiler, air cooled condenser (ACC) and fin fan coolers. Staff completed calculations to determine the worst-case vertical plume velocities at different heights above the stacks based on the project owner's proposed facility design, with staff corrections to some of the operational data. The purpose of this appendix is to provide documentation of the method used to estimate worst-case vertical plume velocity estimates to assist evaluation of the project's impacts on aviation safety in the vicinity of the Amended HBEP.

SUMMARY OF THE DECISION

On October 29, 2014, the Energy Commission approved the HBEP as a 939 MW (nominal output) combined cycle power plant with two power blocks. Each power block would consist of three Mitsubishi Heavy Industries 501DA gas turbine generators coupled with one steam turbine, in a combined cycle configuration. The Final Commission Decision (CEC 2014bb) of HBEP concluded that the average velocity of the gas turbines drops below 4.3 m/s at the height of 1,740 feet (with two plumes fully merged). The Final Commission Decision also shows that the vertical plume velocity for the air cooled condenser (ACC) would drop below 4.3 m/s at a lower height, between 1,000 and 1,100 feet above ground level (AGL).

PROJECT DESCRIPTION

The Amended HBEP would be a natural-gas-fired, combined-cycle and simple-cycle, air-cooled electrical generating facility located on the site of the existing Huntington Beach Generating Station (HBGS) in Huntington Beach, California. The combined-cycle power block would consist of one two-on-one combined-cycle unit – two GE Frame 7FA.05 gas turbines, two unfired heat recovery steam generators (HRSGs), one steam turbine generator, one air-cooled condenser, one natural-gas-fired auxiliary boiler, and related ancillary equipment. The other power block would include two simple cycle GE LMS-100PB combustion turbines with one fin-fan cooler each and their separate ancillary equipment.

PLUME VELOCITY CALCULATION METHOD

SPILLANE APPROACH

Staff uses a calculation approach from a technical paper (Best 2003) to estimate the worst-case plume vertical velocities for vertical turbulence from plumes such as the Amended HBEP stacks and cooling system. The calculation approach, which is also known as the “Spillane approach”, used by staff is limited to calm wind conditions, which are the worst-case wind conditions. The Spillane approach uses the following equations to determine vertical velocity for single stacks during dead calm wind (i.e., wind speed = 0) conditions:

(1) $(V^*a)^3 = (V^*a)_o^3 + 0.12^*F_o^*[(z-z_v)^2-(6.25D-z_v)^2]$

(2) $(V^*a)_o = V_{exit}^*D/2^*(T_a/T_s)^{0.5}$

(3) $F_o = g^*V_{exit}^*D^2{}^*(1-T_a/T_s)/4$

(4) $Z_v = 6.25D^*[1-(T_a/T_s)^{0.5}]$

Where: V = vertical velocity (m/s), plume-average velocity
a = plume top-hat radius (m, increases at a linear rate of a = $0.16^*(z- z_v)$
F_o= initial stack buoyancy flux m^4/s^3
z = height above ground (m)
z_v= virtual source height (m)
V_{exit}= initial stack velocity (m/s)
D = stack diameter (m)
T_a= ambient temperature (K)
T_s= stack temperature (K)
g = acceleration of gravity (9.8 m/s^2)

Equation (1) is solved for V at any given height above ground that is above the momentum rise stage for single stacks (where z > 6.25D) and at the end of the plume merged stage for multiple plumes. This solution provides the plume-average velocity for the area of the plume at a given height above ground; the peak plume velocity would be two times higher than the plume-average velocity predicted by this equation. The stack buoyancy flux (Equation 3) is a prominent part of Equation (1). The calm condition calculation basis clearly represents the worst-case conditions, and the vertical velocity will decrease substantially as wind speed increases.

For multiple stack plumes, where the stacks are equivalent as is the case for HBEP, the multiple stack plume velocity during calm winds is calculated by staff in a simplified fashion, presented in the Best Paper as follows:

(5) $V_m = V_{sp}^*N^{0.25}$

Where: V_m = multiple stack combined plume vertical velocity (m/s)
V_{sp} = single plume vertical velocity (m/s), calculated using Equation (1)
N = number of stacks

This simplified multiple stack plume velocity calculation method predicts somewhat lower velocity values than the full Spillane approach methodology for multiple plumes as given in data results presented in the Best paper (Best 2003). However, for a long linear set of plumes, such as the ACC designed for the Amended HBEP project, it is very unlikely that all plumes can merge fully to allow this velocity given the stack separation and the height/atmospheric conditions needed for them to fully merge. Therefore the use of this approach will likely over predict the combined plume velocities in this case.

MITRE EXHAUST PLUME ANALYZER

On September 24, 2015, the Federal Aviation Administration (FAA) released a guidance memorandum (FAA 2015) recommending that thermal plumes be evaluated for air traffic safety. FAA determined that the overall risk associated with thermal plumes in causing a disruption of flight is low. However, it determined that such plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight (such as take-off and landing). In this memorandum a new computer model, different than the analysis technique used by staff and identified above as the Spillane Approach, is used to evaluate vertical plumes for hazards to light aircraft. It was prepared under FAA funding and available for use in evaluating exhaust plume impacts.

This new model, the MITRE Corporation's Exhaust Plume Analyzer (MITRE 2012), was identified by the FAA as a potentially effective tool to assess the impact that exhaust plumes may impose on flight operations in the vicinity of airports (FAA 2015). The Exhaust Plume Analyzer was developed to evaluate aviation risks from large thermal stacks, such as turbine exhaust stacks. The model provides output in the form of graphical risk probability isopleths ranging from 10^{-2} to 10^{-7} risk probabilities for both severe turbulence and upset conditions for four different aircraft sizes. However, at this time the Exhaust Plume Analyzer model cannot be used to provide reasonable risk predictions on variable exhaust temperature thermal plume sources, such as cooling towers and air cooled condensers.

The FAA has not provided guidance on how to evaluate the risk probability isopleth output of the Exhaust Plume Analyzer model, but states in their memorandum that they intend to update their guidance on near-airport land use, including evaluation of thermal exhaust plumes, in fiscal year 2016. However, MITRE Corporation is suggesting that a probability of severe turbulence at an occurrence level of greater than 1×10^{-7} (they call this a Target Safety Level) should be considered potentially significant. This is equivalent to one occurrence of severe aircraft turbulence in 10 million flights. For the past 50 years, the MITRE Corporation has provided air traffic safety guidance to FAA, and their recommended Target Safety Level is based on this experience (MITRE 2016).

Additionally, the MITRE model has a probability of occurrence plot limitation. While it provides output for predict plumes up to a maximum height of 3,500 feet above ground, the meteorological data that is used by the model is currently limited to a maximum height of 3,000 feet, so any higher altitudes simply reuse the 3,000 foot meteorological data. The model was developed with the assumption that a plume would not rise higher than 3,000-3,500 feet above ground level, so the modeling output was terminated at that height[2]. The effort to expand the data set and model to work properly at altitudes above 3,000 feet above ground level is such that the MITRE Corporation would need additional funding.

The MITRE Exhaust Plume Analyzer model uses site specific computer-generated, three dimensional meteorological data (atmospheric temperature and wind speed, varying with height above ground at the specific site location) combined with a series of aircraft conditions related to the determination of turbulence effects and upset to develop the modeling output. The data sources used to create the site specific meteorological data are from the National Oceanic and Atmospheric Administration's National Weather Service (NWS). These computer-generated data are averaged over 13-kilometer grid cells using a model covering the continental United States. The specific NWS measuring stations that provide this data were not identified in the model documentation. The model uses three years of the computer-generated site specific hourly meteorological data to perform these calculations (MITRE 2012).

Staff conducted a preliminary evaluation using the MITRE model for the proposed GE 7FA.05 turbines and GE LMS-100PB turbines plumes, and results for the level of significance recommended by MITRE Corporation (1×10^{-7}) were above 3,000 feet above ground, outside the recommended output range of the model and above the 3,500 foot level provided as the highest extent in the model's graphical output files. At this time staff does not believe the MITRE model should be used for final work products until the vertical axis is extended, the significance threshold is verified by the FAA and the model capabilities are enhanced to include other thermal plume sources such as cooling towers and air-cooled condensers.

STAFF ANALYSIS

This appendix uses the Spillane Approach method to be consistent with staff assessments done for other projects and because the Spillane Approach is described in the FAA materials as providing similar risk assessments for light aircraft. As stated above, staff will consider using the new MITRE method to the extent that it is applicable after conducting further review of the FAA methodology and once FAA develops guidance on how to evaluate the output of the Exhaust Plume Analyzer.

[2] This recommendation seems to be based on MITRE's worst case exhaust assumptions that are similar to the exhaust conditions of a GE LM6000 gas turbine operating in simple cycle mode. However, there are many larger turbines operating in simple cycle mode, such as the GE LMS100 gas turbines proposed for the Amended HBEP that have about twice the thermal exhaust output of a GE LM6000 gas turbine.

EQUIPMENT DESIGN AND OPERATING PARAMETERS

GE 7FA.05 COMBUSTION GAS TURBINE DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the GE 7FA.05 combustion gas turbine stacks are provided in **Plume Velocity Table 1**. Staff chose four scenarios from the project owner-provided modeling inputs from the Petition to Amend (PTA) Appendix 5.1B and Appendix 5.1C (HBEP 2015a). Operating parameters chosen were for ambient temperatures of 32, 65.8, and 110 degree Fahrenheit (ºF) at maximum turbine loads to compute worst-case vertical plume velocities. Therefore the exhaust operating parameters shown correspond to full load operation for the corresponding ambient conditions.

Plume Velocity Table 1
GE 7FA.05 CTG Exhaust Parameters

Parameter	**GE 7FA.05**			
Stack Height	150 ft. (45.72 meters)			
Stack Diameter	20 ft. (6.10 meters)			
CTG Load (%)	100			
Ambient Temperature (°F)	32	65.8	110	
With Inlet Air Cooling	No	No	Yes	No
Exhaust Temperature (°F)	216	215	221	223
Exhaust Velocity (ft/s)	66.95	66.21	66.36	58.91
Exhaust Flow Rate (1000 lb/hr)	4,360	4,307	4,268	3,797

Source: HBEP 2015a

GE LMS-100PB COMBUSTION GAS TURBINE DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the GE LMS-100PB combustion gas turbine stacks are provided in **Plume Velocity Table 2**. Staff chose three scenarios from the project owner-provided modeling inputs from the Petition to Amend (PTA) Appendix 5.1B and Appendix 5.1C (HBEP 2015a). Operating parameters chosen were for ambient temperatures of 32, 65.8, and 110 degree Fahrenheit (ºF) at maximum turbine loads to compute worst-case vertical plume velocities. Therefore the exhaust operating parameters shown correspond to full load operation for the corresponding ambient conditions.

Plume Velocity Table 2
GE LMS-100PB CTG Exhaust Parameters

Parameter	GE LMS-100PB		
Stack Height	80 ft. (24.38 meters)		
Stack Diameter	13.5 ft. (4.11 meters)		
CTG Load (%)	100		
Ambient Temperature (°F)	32	65.8	110
With Inlet Air Cooling	No	Yes	Yes
Exhaust Temperature (°F)	789	794	848
Exhaust Velocity (ft/s)	109.18	108.66	96.61
Exhaust Flow Rate (1000 lb/hr)	1,754	1,746	1,473

Source: HBEP 2015a

AUXILIARY BOILER DESIGN AND OPERATING PARAMETERS

Plume Velocity Table 3 shows the design and operating parameter data for the auxiliary boiler stack, which were provided by the project owner in the PTA (HBEP 2015a). Staff chose the operating parameters (shown in **Plume Velocity Table 3**) which correspond to the maximum heat input case to compute worst-case vertical plume velocities.

Plume Velocity Table 3
Auxiliary Boiler Exhaust Parameters

Parameter	Auxiliary Boiler
Stack Height	80 ft. (24.38 meters)
Stack Diameter	3 ft. (0.91 meters)
Exhaust Temperature (°F)	318
Exhaust Velocity (ft/s)	69.6
Exhaust Flow Rate (Actual Cubic Feet per Minute [ACFM])	29,473

Source: HBEP 2015a

AIR-COOLED CONDENSER DESIGN AND OPERATING PARAMETERS

Plume Velocity Table 4 shows the design and operating parameter data for the air-cooled condenser (ACC) for the combined-cycle power block. The project owner provided the data in Data Responses Set 1 (HBEP 2015i). Staff noticed that the project owner-provided outlet air flow rates, outlet air exit velocities, and cell dimensions of the ACC are internally inconsistent with each other. Staff measured the diameter of each fan of the ACC from PTA Figure 2.1-2 General Arrangement/Site Plan (HBEP 2015a). Staff recalculated the outlet air exit velocities using the project owner-provided outlet air flow rates and staff-measured fan diameter. The staff-measured fan diameter and staff-calculated outlet air exit velocities are shown in **Plume Velocity Table 4** with an asterisk symbol (*).

FIN FAN COOLER DESIGN AND OPERATING PARAMETERS

Plume Velocity Table 5 shows the design and operating parameter data for each of the fin fan coolers for the simple-cycle power block. The project owner originally provided the data for the fin fan coolers in Data Responses Set 1 (HBEP 2015i). However, staff noticed that the project owner-provided heat rejection, outlet air flow rates, outlet air exit velocities, and cell dimensions of the fin fan coolers are internally inconsistent with each other. Staff requested the project owner to provide performance data sheets from the vendor and clarify the inconsistencies. The project owner provided follow-up vendor data sheets (HBEP 2016o) for the fin fan coolers. Staff recalculated the outlet air exit velocities and heat rejection rates using the air flow rates, inlet and outlet air temperatures from the vendor data sheets (HBEP 2016o), and the cell diameter from Data Responses Set 1 (HBEP 2015i). Staff corrected the 32ºF ambient temperate case exhaust data using mass and energy balance calculations based on the vendor data supplied by the project owner and the number of fans in operation (12 fans in operation in the 32ºF case rather than 28). The staff-calculated values are shown in **Plume Velocity Table 5** with an asterisk symbol (*).

Plume Velocity Table 4
Air-Cooled Condenser Exhaust Parameters

Parameter	Combined-Cycle Air-Cooled Condenser		
Number of Cells	30		
Cell Height (ft)	53.1		
Cell Diameter (ft)	43.9 (L) x 43.1 (W)		
Fan Diameter (ft) [a]	40*		
Distance Between Cells (ft)	0 ft (adjoining cells share a single column)		
Ambient Temperature	32	65.8	110
Ambient Relative Humidity	87%	58%	8%
Number of Cells in Operation	13	30	28
Heat Rejection (MW)	369.4	378.6	400.9
Outlet Air Temperature (°F)	90.9	92.7	142.2
Outlet Air Exit Velocity (ft/s) [b]	21.79*	21.14*	20.86*
Outlet Air Flow (lb/hr)	92,142,000	205,538,400	173,790,000

Source: HBEP 2015a, HBEP 2015i, and independent staff analysis
Notes:
[a] Staff measured the diameter of each fan from PTA Figure 2.1-2 General Arrangement/Site Plan (HBEP 2015a).
[b] Staff calculated the exit velocities based on the project owner-provided outlet air flow rates and staff-measured fan diameter from PTA.

Plume Velocity Table 5
Fin Fan Cooler Exhaust Parameters

Parameter	Simple-Cycle Fin Fan Cooler		
Number of Cells (Fans)	28 total, 14 bays (2 fan per bay)		
Cell Height (ft)	24		
Cell Diameter (ft)	13		
Ambient Temperature (ºF)	32	65.8	110
Ambient Relative Humidity	87%	58%	8%
Number in Operation	12 fans	28 fans	28 fans
Outlet Air Temperature (ºF)	70.85	82.2	126.26
Air flow rate/fan (acfm/cell) [a]	222,100*	217,467	238,733
Outlet Air Exit Velocity (ft/s) [a]	27.9*	27.31*	29.98*
Heat Rejection (MW) [a]	33.2*	31.3*	31.3*

Source: HBEP 2015i, HBEP 2016o, and independent staff analysis
Note:
[a] Staff calculated the exit velocities and heat rejection rates based on the air flow rates, inlet and outlet air temperatures from the vendor data sheets (HBEP 2016o), and the cell diameter from Data Responses Set 1 (HBEP 2015i). Staff corrected the 32ºF ambient temperate case exhaust data using mass and energy balance calculations based on the vendor data supplied by the project owner and the number of fans in operation (12 fans in operation in the 32ºF case rather than 28).

PLUME VELOCITY CALCULATION RESULTS

Using the Spillane Approach, the plume average vertical velocities at different heights above ground were determined by staff for calm conditions for the proposed gas turbines, auxiliary boiler, air-cooled condenser (ACC) and fin fan coolers. Staff evaluated the potential for plume merging using the following stack-to-stack distances: (1) the distance between the two GE 7FA.05 combined-cycle turbine stacks would be about 44 meters (m), (2) the distance between the two GE LMS-100PB simple-cycle turbine stacks would be about 44 m. Plumes begin merging when the radius of each of the two plumes added together equals the distance between the stacks. As a rule of thumb they are considered fully merged when the sum of the plume radii adds to equal twice the distance between stacks.

As explained in the Transportation and Traffic section, a plume average vertical velocity of 4.3 m/s has been determined by staff to be the critical velocity of concern to light aircraft. This is based on the Australian Civil Aviation Safety Authority (CASA) advisory circular (CASA 2003). Vertical velocities below this level are not of concern to light aircraft.

The combined-cycle power block would have two GE 7FA.05 combined-cycle turbine stacks, with a spacing of about 44 meters from each other. When the spacing between the stacks is not large enough to prevent plume merging, the exhaust plumes may spread enough to significantly merge prior to the velocity lowering to vertical velocities below levels of concern. Therefore, staff calculated the plume size and vertical velocities for the single plume without merging (N=1) and two plumes fully merged (N=2). Staff calculated plume average vertical velocities for all four operating cases shown in **Plume Velocity Table 1** for the GE 7FA.05 turbines and determined that the worst-case predicted plume velocities would occur at full load operation without inlet air cooling at the 32°F ambient temperature condition. Staff's calculated worst-case plume average velocity values are provided in **Plume Velocity Table 6**.

The GE 7FA.05 gas turbine plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 810 feet above ground for the single turbine plume (N=1). The plume diameter at this height would be around 62.6 meters, which would be larger than the distance between the two GE7FA.05 gas turbine stacks (44 meters). Therefore the merging of the adjacent turbine plumes should be considered. In the case of two plumes fully merging (N=2), the average velocity is calculated to drop below 4.3 m/s at the height of 1,220 feet above ground.

Plume Velocity Table 6
GE 7FA.05 Turbine Plume Size (m) and Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Diameter (m) [a]	Plume Velocity (m/s) [b]	
		N=1	N=2
300	12.84	8.84	Not Merged
400	22.59	6.46	Not Merged
500	32.35	5.51	Not Merged
600	42.10	4.96	Not Merged
700	51.85	4.59	Not Merged
800	61.61	4.31	Not Merged
900	71.36	4.09	Not Merged
1,000	81.12	3.91	Not Merged
1,100	90.87	3.76	4.47
1,200	100.62	3.63	4.32
1,300	110.38	3.52	4.18
1,400	120.13	3.42	4.06
1,500	129.88	3.33	3.96
1,600	139.64	3.25	3.86
1,700	149.39	3.17	3.77
1,800	159.14	3.11	3.70
1,900	168.90	3.05	3.62
2,000	178.65	2.99	3.55
2,100	188.41	2.94	3.49

Notes:
a – The separation between the two stacks would be about 44 meters and the plumes will begin to merge when the plume diameter is the same as the separation and is assumed to be fully merged when the plume diameter is twice the stack separation.
b – Not Merged means not fully merged.

The simple-cycle power block would have two GE LMS-100PB simple-cycle turbine stacks, with a spacing of about 44 meters from each other. Staff calculated the plume size and vertical velocities for the single plume without merging (N=1) and two plumes fully merged (N=2). Staff calculated plume average vertical velocities for all three operating cases shown in **Plume Velocity Table 2** for the GE LMS-100PB turbines and determined that the worst-case predicted plume velocities would occur at 100 percent load operation without inlet air cooling at the 32°F ambient temperature condition. Staff's calculated worst-case plume average velocity values are provided in **Plume Velocity Table 7**.

The GE LMS-100PB gas turbine plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 1,140 feet above ground for the single turbine plume (N=1). The plume diameter at this height would be around 100.3 meters, which would be larger than the distance between the two GE LMS-100PB gas turbine stacks (44 meters). Therefore the merging of the adjacent turbine plumes should be considered. In the case of two plumes fully merging (N=2), the average velocity is calculated to drop below 4.3 m/s at the height of 1,820 feet above ground.

Plume Velocity Table 7
GE LMS-100PB Turbine Plume Size (m) and Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Diameter (m) [a]	Plume Velocity (m/s) [b]	
		N=1	N=2
300	18.39	7.91	Not Merged
400	28.15	6.68	Not Merged
500	37.90	5.99	Not Merged
600	47.65	5.53	Not Merged
700	57.41	5.18	Not Merged
800	67.16	4.91	Not Merged
900	76.92	4.69	Not Merged
1,000	86.67	4.50	Not Merged
1,100	96.42	4.34	5.16
1,200	106.18	4.20	5.00
1,300	115.93	4.08	4.85
1,400	125.68	3.97	4.72
1,500	135.44	3.87	4.61
1,600	145.19	3.79	4.50
1,700	154.94	3.70	4.40
1,800	164.70	3.63	4.32
1,900	174.45	3.56	4.23
2,000	184.21	3.50	4.16
2,100	193.96	3.44	4.09

Notes:
a – The separation between the two stacks would be about 44 meters and the plumes will begin to merge when the plume diameter is the same as the separation and is assumed to be fully merged when the plume diameter is twice the stack separation.
b – Not Merged means not fully merged.

Staff also calculated plume average vertical velocities for the auxiliary boiler using the operating parameters shown in **Plume Velocity Table 3**. **Plume Velocity Table 8** shows the worst-case plume average velocity values for the auxiliary boiler. The auxiliary boiler plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 130 feet above ground.

Plume Velocity Table 8
Auxiliary Boiler Plume Size (m) and Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Diameter (m)	Plume Velocity (m/s)
100	1.58	9.83
110	2.55	6.38
120	3.53	4.92
130	4.50	4.12
140	5.48	3.63
150	6.45	3.29
160	7.43	3.05
170	8.40	2.86
180	9.38	2.72
190	10.35	2.60
200	11.33	2.49
210	12.31	2.41
220	13.28	2.33
230	14.26	2.27
240	15.23	2.21
250	16.21	2.16
260	17.18	2.11
270	18.16	2.07
280	19.13	2.03
290	20.11	1.99
300	21.08	1.95

Staff calculated plume average vertical velocities for all three operating cases shown in **Plume Velocity Table 4** for the combined-cycle's air-cooled condenser and determined that the worst-case height at which the plume velocities would drop below 4.3 m/s would occur at 32°F ambient temperature condition. Staff assumed that the plumes from all cells in operation would be fully merged. Staff's calculated worst-case plume average velocity values are provided in **Plume Velocity Table 9**. The combined-cycle air-cooled condenser plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 2,200 feet above ground.

Plume Velocity Table 9
Combined-Cycle Air-Cooled Condenser Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Velocity (m/s)
400	7.01
500	6.82
600	6.53
700	6.26
800	6.01
900	5.79
1,000	5.59
1,100	5.42
1,200	5.27
1,300	5.13
1,400	5.00
1,500	4.89
1,600	4.78
1,700	4.69
1,800	4.60
1,900	4.51
2,000	4.44
2,100	4.36
2,200	4.30
2,300	4.23
2,400	4.17
2,500	4.11

Finally, staff calculated plume average vertical velocities for all three operating cases shown in **Plume Velocity Table 5** for the simple-cycle fin fan coolers determined that the worst-case height at which the plume velocities would drop below 4.3 m/s would occur at 110°F ambient temperature condition. Staff assumed that the plumes from all cells in operation would be fully merged. Staff's calculated worst-case plume average velocity values are provided in **Plume Velocity Table 10**. The combined-cycle air-cooled condenser plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 280 feet above ground.

Plume Velocity Table 10
Simple-Cycle Fin Fan Cooler Vertical Plume Velocities (m/s)

Height Above Ground Level (Feet)	Plume Velocity (m/s)
110	9.97
120	9.02
130	8.26
140	7.63
150	7.12
160	6.68
170	6.31
180	5.99
190	5.71
200	5.46
210	5.25
220	5.06
230	4.89
240	4.73
250	4.59
260	4.47
270	4.35
280	4.24
290	4.15
300	4.06

The velocity values listed above in **Plume Velocity Table 6** through **Plume Velocity Table 10** are plume average velocities across the area of the plume. The maximum plume velocity, based on a normal Gaussian distribution, is two times the plume average velocities shown in the tables.

It should be noted that additional thermal plume merging between the gas turbine stacks, the air-cooled condenser, the auxiliary boiler, and the fin fan coolers could occur and increase the plume heights where vertical velocities of 4.3 m/s are exceeded under worst case conditions. The model used for this analysis is not able to add different kinds of thermal plumes together. However, the approach is still conservative given the conservatism built in the model.

WIND SPEED STATISTICS

The Air Quality section of this document uses meteorological data from John Wayne airport station, which is about 6.6 miles northeast of the Amended HBEP site. The wind roses and wind frequency distribution data collected from the John Wayne airport station were considered to be representative for the project site location. The project owner provides the calm wind speed statistics for John Wayne airport station from ground-level meteorological data collected for 2010 through 2014 (HBEP 2015a). Calm winds for the purposes of the reported monitoring station statistics are those hours with average wind speeds below 0.5 m/s. Calm or very low wind speeds can also occur for shorter periods of time within each of the monitored average hourly conditions. However, the shortest time resolution for the available meteorological data is one hour. The annual wind rose data shows calm/low wind speed conditions averaging an hour or longer is 2.8 percent in the site area, or about 245 hours per year.

CONCLUSIONS

The worst case calm wind condition vertical plume average velocities from the proposed GE 7FA.05 combined-cycle turbine stacks are predicted to drop below 4.3 m/s at the height of 1,220 feet assuming two plumes fully merged. The worst case calm wind condition vertical plume average velocities from the proposed GE LMS-100PB turbine stacks are predicted to drop below 4.3 m/s at the height of 1,820 feet assuming two plumes fully merged. The worst case auxiliary boiler plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 130 feet. The worst case air-cooled condenser plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 2,200 feet. The worst case plume average velocity for each of the fin fan coolers is calculated to drop below 4.3 m/s at a height of approximately 280 feet. Thus, the thermal plume from the proposed air-cooled condenser would cause greatest risk to light aircraft.

Also, there is the potential for additional thermal plume merging between the gas turbine stacks and the air-cooled condenser or fin fan coolers that could increase the plume heights where vertical velocities of 4.3 m/s are exceeded under worst case conditions. Calm/low wind speed conditions (wind speeds less than 0.5 m/s) conducive to the formation of worst-case thermal plume velocities would occur on average approximately 2.8 percent of the time.

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FAA 2015 - Federal Aviation Administration Memorandum – Technical Guidance and Assessment Tool for Evaluation of Thermal Plume Impact on Airport Operations (September 24, 2015).

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

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MITRE 2012 - Expanded Model for Determining the Effects of Vertical Plumes on Aviation Safety, Gouldley, Hopper and Schwalbe, MITRE Product MP 120461, September 2012.

MITRE 2016 - Center for Advanced Aviation System Development [http://www.mitre.org/centers/center-for-advanced-aviation-system-development/who-we-are], website accessed 2-23-2016.

VISUAL RESOURCES ATTACHMENT-1

Complaint Report and Resolution Form

Facility Name: Amended Huntington Beach Energy Project **Complaint Log No:**	
Complaintant's name and address:	Phone No:
Date and time complaint received: Complaint filed: ☐ By Telephone ☐ In Writing (attach letter) ☐ In Person Date of first occurrence:	
Description of the complaint (lighting, duration, etc.):	
Findings of investigation by AES personnel: Indicate if complaint relates to a violation of an Energy Commission condition: ☐ Yes ☐ No Date complainant contacted to discuss findings:	
Description of corrective measures taken or other complaint resolution: Indicate if complainant agrees with proposed resolution: If not, explain: Additional relevant information:	
If corrective action necessary, date completed: Date of first response to complainant: (attach copy) Date of final response to complainant: (attach copy)	
This information is certified to be correct: Power plant or project manager's signature:	Date:

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
WASTE MANAGEMENT
Ellen Townsend-Hough

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Huntington Beach Energy Project (HBEP) proposes to modify the project, resulting in changes to an existing Waste Management condition of certification **WASTE-5**. Similar to the conclusions in the licensed HBEP 2014 Energy Commission Final Decision (Decision), the potential impacts of the proposed PTA would be less than significant if mitigated in accordance with the adopted conditions of certification. 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 2014 Decision is necessary for Waste Management. The Committee may rely upon the environmental analysis and conclusions of the Commission Decision with regards to Waste Management and does not need to re-analyze them.

The City of Huntington Beach would be responsible for waste conservation programs within the city's limits. Therefore **WASTE-5** would be modified to have the project owner provide a Construction and Demolition Debris Waste Reduction and Recycling Plan to the compliance project manager (CPM) and the city of Huntington Beach.

As with the HBEP Decision, the amount of waste generated by the HBEP would not significantly impact nonhazardous or hazardous landfill capacity. As with the licensed HBEP, the amended HBEP would be consistent with the applicable waste management laws, ordinances, regulations, and standards (LORS) if staff's approved conditions of certification, with the previously described modification, are implemented.

INTRODUCTION

In this section, Energy Commission staff discusses potential impacts of the proposed amendment 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 HBEP Decision did not find any immitigable impacts to waste management. The Decision required conditions **WASTE-1** through **WASTE-8** to account for the different types of wastes that would 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. The Decision assesses the adequacy of the waste management plan with respect to handling, storage and disposal of these wastes. The Waste Management analysis also evaluated the likelihood the project site contains hazardous waste.

Waste Management Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Federal	
Title 42, United States Code, §§ 6901, et seq. Solid Waste Disposal Act of 1965 (as amended and revised by the Resource Conservation and Recovery Act of 1976, et al.)	The Solid Waste Disposal Act, as amended and revised by the Resource Conservation and Recovery Act (RCRA) et al., establishes requirements for the management of solid wastes (including hazardous wastes), landfills, underground storage tanks, and certain medical wastes. The statute also addresses program administration, implementation, and delegation to states, enforcement provisions, and responsibilities, as well as research, training, and grant funding provisions. RCRA Subtitle C establishes provisions for the generation, storage, treatment, and disposal of hazardous waste, including requirements addressing: generator record keeping practices that identify quantities of hazardous wastes generated and their disposition; waste labeling practices and use of appropriate containers; use of a manifest when transporting wastes; submission of periodic reports to the United States Environmental Protection Agency (U.S. EPA) or other authorized agency; and corrective action to remediate releases of hazardous waste and contamination associated with RCRA-regulated facilities. RCRA Subtitle D establishes provisions for the design and operation of solid waste landfills. RCRA is administered at the federal level by U.S. EPA and its 10 regional offices. The Pacific Southwest regional office (Region 9) implements U.S. EPA programs in California, Nevada, Arizona, and Hawaii.
Title 42, United States Code, §§ 9601, et seq. Comprehensive Environmental Response, Compensation and Liability Act	The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as Superfund, establishes authority and funding mechanisms for cleanup of uncontrolled or abandoned hazardous waste sites, as well as cleanup of accidents, spills, or emergency releases of pollutants and contaminants into the environment. Among other things, the statute addresses: reporting requirements for releases of hazardous substances; requirements for remedial action at closed or abandoned hazardous waste sites and brownfields; liability of persons responsible for releases of hazardous substances or waste; and requirements for property owners/potential buyers to conduct “all appropriate inquiries” into previous ownership and uses of the property to 1) determine if hazardous substances have been or may have been released at the site and 2) establish that the owner/buyer did not cause or contribute to the release. A Phase I Environmental Site Assessment is commonly used to satisfy CERCLA “all appropriate inquiries” requirements.
Title 40, Code of Federal Regulations (CFR), Subchapter I – Solid Wastes	These regulations were established by U.S. EPA to implement the provisions of the Solid Waste Disposal Act and RCRA (described above). Among other things, the regulations establish the criteria for classification of solid waste disposal facilities (landfills), hazardous waste characteristic criteria and regulatory thresholds, hazardous waste generator requirements, and requirements for management of used oil and universal wastes. Part 246 addresses source separation for materials recovery guidelines. Part 257 addresses the criteria for classification of solid waste disposal facilities and practices. Part 258 addresses the criteria for municipal solid waste landfills. Parts 260 through 279 address management of hazardous wastes, used oil, and universal wastes (i.e., batteries, mercury-containing equipment, and lamps). U.S. EPA implements the regulations at the federal level. However, California is an authorized state so the regulations are implemented by state agencies and authorized local agencies in lieu of U.S. EPA.

Applicable LORS	Description
Title 49, CFR, Parts 172 and 173 Hazardous Materials Regulations	U.S. Department of Transportation established standards for transport of hazardous materials and hazardous wastes. The standards include requirements for labeling, packaging, and shipping of hazardous materials and hazardous wastes, as well as training requirements for personnel completing shipping papers and manifests. Section 172.205 specifically addresses use and preparation of hazardous waste manifests in accordance with Title 40, CFR, section 262.20.
State	
California Health and Safety Code, Chapter 6.5, §§ 25100, et seq. Hazardous Waste Control Act of 1972, as amended	This California law creates the framework under which hazardous wastes must be managed in California. The law provides for the development of a state hazardous waste program that administers and implements the provisions of the federal RCRA program. It also provides for the designation of California-only hazardous wastes and development of standards (regulations) that are equal to or, in some cases, more stringent than federal requirements. The California Environmental Protection Agency (Cal/EPA), Department of Toxic Substances Control (DTSC) administers and implements the provisions of the law at the state level. Certified Unified Program Agencies (CUPAs) implement some elements of the law at the local level.
Title 22, California Code of Regulations (CCR), Division 4.5 Environmental Health Standards for the Management of Hazardous Waste	These regulations establish requirements for the management and disposal of hazardous waste in accordance with the provisions of the California Hazardous Waste Control Act and federal RCRA. As with the federal requirements, waste generators must determine if their wastes are hazardous according to specified characteristics or lists of wastes. Hazardous waste generators must obtain identification numbers, prepare manifests before transporting the waste off site, and use only permitted treatment, storage, and disposal facilities. Generator standards also include requirements for record keeping, reporting, packaging, and labeling. Additionally, while not a federal requirement, California requires that hazardous waste be transported by registered hazardous waste transporters. The standards addressed by Title 22, CFR include: Identification and Listing of Hazardous Waste (Chapter 11, §§ 66261.1, et seq.), Standards Applicable to Generators of Hazardous Waste (Chapter 12, §§ 66262.10, et seq.), Standards Applicable to Transporters of Hazardous Waste (Chapter 13, §§ 66263.10, et seq.), Standards for Universal Waste Management (Chapter 23, §§ 66273.1, et seq.), Standards for the Management of Used Oil (Chapter 29, §§ 66279.1, et seq.), Requirements for Units and Facilities Deemed to Have a Permit by Rule (Chapter 45, §§ 67450.1, et seq.) The Title 22 regulations are established and enforced at the state level by DTSC. Some generator standards are also enforced at the local level by CUPAs.
California Health and Safety Code, Chapter 6.11 §§ 25404–25404.9 Unified Hazardous Waste and Hazardous Materials Management Regulatory Program (Unified Program)	The Unified Program consolidates, coordinates, and makes consistent the administrative requirements, permits, inspections, and enforcement activities of the six environmental and emergency response programs listed below. Aboveground Storage Tank Program Business Plan Program California Accidental Release Prevention (CalARP) Program Hazardous Material Management Plan / Hazardous Material Inventory Statement Program Hazardous Waste Generator / Tiered Permitting Program Underground Storage Tank Program The state agencies responsible for these programs set the standards for their programs while local governments implement the standards. The local agencies implementing the Unified Program are known as Certified Unified Program Agencies (CUPAs). Orange County Department of Environmental Health is the area CUPA. Note: The Waste Management analysis only considers application of the Hazardous Waste Generator/Tiered Permitting element of the Unified Program. Other elements of the Unified Program may be addressed in the Hazardous Materials and/or Worker Health and Safety analysis sections.

Applicable LORS	Description
Title 27, CCR, Division 1, Subdivision 4, Chapter 1, §§ 15100, et seq. Unified Hazardous Waste and Hazardous Materials Management Regulatory Program	While these regulations primarily address certification and implementation of the program by the local CUPAs, the regulations do contain specific reporting requirements for businesses. Article 9 – Unified Program Standardized Forms and Formats (§§ 15400–15410). Article 10 – Business Reporting to CUPAs (§§ 15600–15620).
Public Resources Code, Division 30, §§ 40000, et seq. California Integrated Waste Management Act of 1989.	The California Integrated Waste Management Act of 1989 (as amended) establishes mandates and standards for management of solid waste. Among other things, the law includes provisions addressing solid waste source reduction and recycling, standards for design and construction of municipal landfills, and programs for county waste management plans and local implementation of solid waste requirements. The act was amended in 2011 (AB 341) to include a legislative declaration of a state policy goal that not less than 75 percent of solid waste generated be source reduced, recycled, or composted by the year 2020. The 2011 amendments expand recycling to businesses and apartment buildings; require the state to develop programs to recycle three-quarters of generated waste; and require commercial and public entities that generate more than four cubic yards of commercial solid waste per week, and multifamily residential dwellings of five units or more, to arrange for recycling services beginning July 1, 2012.
Title 14, CCR, Division 7, § 17200, et seq. California Integrated Waste Management Board	These regulations further implement the provisions of the California Integrated Waste Management Act and set forth minimum standards for solid waste handling and disposal. The regulations include standards for solid waste management, as well as enforcement and program administration provisions. Chapter 3 – Minimum Standards for Solid Waste Handling and Disposal. Chapter 3.5 – Standards for Handling and Disposal of Asbestos Containing Waste. Chapter 7 – Special Waste Standards. Chapter 8 – Used Oil Recycling Program. Chapter 8.2 – Electronic Waste Recovery and Recycling.
California Health and Safety Code, Division 20, Chapter 6.5, Article 11.9, §25244.12, et seq. Hazardous Waste Source Reduction and Management Review Act of 1989 (also known as SB 14).	This law was enacted to expand the state's hazardous waste source reduction activities. Among other things, it establishes hazardous waste source reduction review, planning, and reporting requirements for businesses that routinely generate more than 12,000 kilograms (~ 26,400 pounds) of hazardous waste in a designated reporting year. The review and planning elements are required to be done on a 4-year cycle, with a summary progress report due to DTSC every 4th year.
Title 22, CCR, § 67100.1 et seq. Hazardous Waste Source Reduction and Management Review.	These regulations further clarify and implement the provisions of the Hazardous Waste Source Reduction and Management Review Act of 1989 (noted above). The regulations establish the specific review elements and reporting requirements to be completed by generators subject to the act.

Applicable LORS	Description
California Health and Safety Code Section 101480 101490	These regulations authorize a local officer, such as the director of the Orange County Department of Environmental Health to enter into voluntary agreements for the oversight of remedial action at sites contaminated by wastes.
Title 22, CCR, Chapter 32, §67383.1 – 67383.5	This chapter establishes minimum standards for the management of all underground and aboveground tank systems that held hazardous waste or hazardous materials, and are to be disposed, reclaimed or closed in place.
Title 8, CCR §1529 and §5208	These regulations require the proper removal of asbestos containing materials in all construction work and are enforced by California Occupational Safety and Health Administration (Cal-OSHA).
Title 14, Chapter 9 Division 7 –(AB 939)	AB 939 established the organization, structure, and mission of California Integrated Waste Management Board (CIWMB) in 1989. AB 939 not only mandated local jurisdictions to meet numerical diversion goals of 25% by 1995 and 50% by 2000, but also established an integrated framework for program implementation, solid waste planning, and solid waste facility and landfill compliance. Other elements included encouraging resource conservation and considering the effects of waste management operations. The diversion goals and program requirements are implemented through a disposal based reporting system by local jurisdictions under CIWMB regulatory oversight. Facility compliance requirements are implemented under a different approach primarily through local government enforcement agencies. Cal Recycle, formerly known as the CIWMB, is the state's leading authority on recycling, waste reduction, and product reuse officially known as the Department of Resources Recycling and Recovery
Cal OSHA's Lead in Construction Standard is contained in Title 8, Section 1532.1 of the California Code of Regulations	The regulations address all of the following areas: permissible exposure limits (PELs); exposure assessment; compliance methods; respiratory protection; protective clothing and equipment; housekeeping; medical surveillance; medical removal protection (MRP); employee information, training, and certification; signage; record keeping; monitoring; and agency notification.
Title 17, CCR, Division 1, Chapter 8, Section 35001	Requirements for lead hazard evaluation and abatement activities, accreditation of training providers, and certification of individuals engaged in lead-based paint activities.
Local	
South Coast Air Quality Management District (SCAQMD) Rule 1403	This rule establishes survey requirements, notification and work practice requirements to prevent asbestos emissions from emanating during renovation and demolition activities. SCAQMD Rule 1403 incorporates the requirements found in National Emissions Standard for Hazardous Air Pollutants (NESHAP) in code of Federal Regulations (CFR) Title 40, Part 61, Subpart M.
Huntington Beach Fire Department City Specifications Underground Storage Tanks (city Spec 418). Aboveground Storage Tanks (City Spec 425), Soil Cleanup Standards (City Specs 431-92)	The Huntington Beach Fire Department administers the Hazardous Waste, Underground Storage Tank, and Aboveground Petroleum Storage Tank programs

Applicable LORS	Description
Orange County Integrated Waste Management Plan	The plan provides guidance for local management of solid waste and household hazardous waste (incorporates the county's Source Reduction and Recycling Elements, which detail means of reducing commercial and industrial sources of solid waste).
Orange County Health Care Agency - Environmental Health Division, Hazardous Waste Inspection Program	Hazardous Material Division is the Certified Unified Program Agency (CUPA) for Orange County that regulates and conducts inspections of businesses that handle hazardous materials, hazardous wastes, and/or have underground storage tanks. Hazardous Material Division programs include assistance with oversight on property re-development (i.e., brownfields) and voluntary or private oversight cleanup assistance.
Policy	
Construction & Demolition (C&D) Recycling and Reuse Program Policy	This policy and ensuing program are designed to assist the county in compliance with this state mandate. The Integrated Waste Management Act of 1989 (AB939) required cities and counties to reduce, by 50%, the amount of waste disposed of in landfills by the year 2000 and beyond or potentially incur fines of up to $10,000 per day.

Updated LORS that would apply to HBEP since the licensing of HBEP in 2015 are briefly described below.

Laws, Ordinances, Regulations, And Standards

Huntington Beach C&D Ordinance Section 8.21	Construction and Demolition (C&D) Debris Re-Use and Recycling Program. Recycle and/or salvage for reuse a minimum of 50 percent of the nonhazardous C&D or meet a local C&D ordinance.
2013 CALGREEN Code Division 5.1 - Non Residential Mandatory Measures: Material Conservation and Resource Efficiency-Section 5.408	Construction waste management - recycle and/or salvage for reuse a minimum of 50 percent of the nonhazardous construction and demolition waste (C&D) or meet a local C&D ordinance, whichever is more stringent.
2013 CALGREEN Code Division 5.1 Section 5.408.1.1	Construction waste management plan. Where a local jurisdiction does not have a C&D waste management ordinance that is more stringent, submit a construction waste management plan that: (1) identifies C&D waste material to be diverted from disposal to be recycled, reused, or salvaged; (2) determines if C&D waste can be sorted on site; (3) identifies diversion facilities; and (4) specifies the amount of C&D waste material diverted by weight or volume.

Additional information can be found at: http://www.huntingtonbeachca.gov/files/users/building/C-and-D-Recycling-Worksheet.pdf. Management of wastes generated during construction and operation of the HBEP would not result in any significant adverse impacts and would comply with applicable waste management laws, ordinances, regulations, and standards if the measures proposed in the PTA and staff's proposed conditions of certification are implemented.

Effective January 1, 2014, CALGreen mandates permitted non-residential building construction, demolition and certain additions and alteration projects recycle and/or salvage for reuse a minimum 50 percent of the nonhazardous C&D debris generated during the project (CALGreen Sections 5.408, 301.1.1, and 301.3). To comply with this new law condition of certification **WASTE-5** has been modified to require the project owner to provide a C&D Debris Waste Reduction and Recycling Plan to the CPM and the city of Huntington Beach Department of Planning and Building.

ENVIRONMENTAL IMPACT ANALYSIS

Staff reviewed the HBEP 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.

On October 29, 2014 the Energy Commission issued the Decision authorizing AES Southland, LLC to construct and operate the HBEP, a nominal 939-megawatt (MW) natural gas-fired, combined-cycle, air-cooled, electrical generating facility on a 28.6-acre site. AES Southland, LLC filed the PTA September 14, 2015. The petition proposes to replace the original project with an 844-MW nominal capacity facility at the Huntington Beach site. The proposed changes are outlined in **Waste Management Table 2. Waste Management Table 2** provides a limited comparison of the licensed HBEP project to the proposed HBEP PTA (HBEP 2015b page 2-2). For a complete description of the PTA refer to the HBEP **PROJECT DESCRIPTION**.

Waste Management Table 2
Licensed vs. Amended Huntington Beach Features Potentially Impacting Waste Management

Feature	Licensed HBEP (939 MW)	Amended HBEP (844 MW)
Power Production	Power Block 1: 3 combustion turbine generators, 3 supplemental-fired heat recovery steam generators, 1 steam turbine generator, air cooled condenser	Power Block 1: two combustion turbine generators, 2 heat recovery steam generators (no supplemental firing), 1 steam turbine generator, air cooled condenser
	Power Block 2: 3 combustion turbine generators, 3 heat recovery steam generators, 1 steam turbine generator, air cooled condenser, and an auxiliary boiler	Power Block 2: two simple-cycle gas turbines
Project footprint	28.6 acres	30 acres
Area of temporary construction laydown and parking	1.9 acres	22 acres
Demolition of Units 1 & 2	Existing units demolished to their foundation	Demolish existing units down to the steam turbine deck

Sources: CEC 2015b, HBEP 2015a page 5.14-2, HBEP 2015F, HBEP 2015G

HBEP PTA would construct Power Block1 and Block 2 in similar locations as the licensed project. The Construction of amended Block 1 would require the demolition of Huntington Beach Generating Station (HBGS) retired Unit 5 (a retired combustion turbine generator unit) and two former oil tanks. To build Block 2, HBGS Units 3 and 4 would be demolished. HBGS Units 1 and 2, associated fuel oil pipelines and containment berms, would also be demolished. Existing HBGS Units 3 and 4 were licensed through California Energy Commission license 00-AFC-13C and are not part of the HBEP PTA definition. Demolition of Units 3 and 4 would occur irrespective of HBEP (PTA page 2-12).

SITE CONDITIONS

The proposed project site would be located within the existing HBGS site on 30 acres at 21730 Newland Street, in Huntington Beach, Orange County, California. HBGS is a highly disturbed industrial brownfield site. HBGS currently consists of five units. Units 1 and 2 are in operation. Units 3 and 4 were decommissioned in 2012 and converted to synchronous condensers[1], and Unit 5, a peaking unit, was retired in 2002.

The Huntington Beach Generating Station Phase I Environmental Site Assessment (ESA) report for the slightly larger 30-acre site concluded that a number of Recognized Environmental Conditions, Historical Recognized Environmental Conditions, and De Minimis Conditions are present at the existing site (HBEP 2012a Volume II). They are as follows:

- Plugged oil and gas wells both onsite and adjacent to the east;
- Known contamination below existing aboveground storage tanks (Plains America tanks), distillate tank, and presence of fuel pipelines onsite;
- Groundwater below the site affected by metals, volatile organic compounds (VOC), and 1,4-dioxane;
- Former extensive use of fuel oil;
- Former use of concrete degreasing pits;
- Former use of polychlorinated biphenyl -containing oil and suspected transformer oil;
- Large number of recorded underground storage tanks onsite without removal or closure documentation; and
- Known groundwater contamination on adjacent property to the north.

[1] Synchronous condensers provide voltage support to the grid, but do not generate electricity.

All of these site conditions are the same as those identified in the Phase I ESA for the 28.6 acre site in the original analysis. The main environmental concerns discussed in the ESA were the presence of asbestos containing buildings, lead based paint, and soil and water contaminated with VOCs. The project owner is currently in discussions with the Department of Toxic Substances Control Chatsworth Office to identify, quantify and remediate past contamination issues at the HBGS (HBEP 2012n Data Request 69). Existing and discovered contamination would be remediated prior to the construction of HBEP (HBEP 2012n Data Response 70).

Demolition would begin with the decommissioned Unit 5 peaker, the east fuel oil storage tank, the distillate storage tank, the fuel oil pipelines and berms (HBEP 2015a page 2-12). HBEP Block 1, the combined-cycle units, would be constructed where Unit 5 and the two fuel oil storage tanks are located. HBEP Block 2, the two 100-MW simple-cycle units, would be constructed where HBGS Units 3 and 4 are located (HBEP 2015e page 2-1). HBGS Units 3 and 4 were licensed as part of the Huntington Beach Generating Station Modernization Project (00-AFC-13C) and their demolition is not considered part of the HBEP (HBEP 2015e page 2-1). Unit 1 would be retired to make room for interconnection capacity for the combined-cycle plant. Unit 2 would be demolished after the construction of the simple-cycle units (HBEP 2015e page 2-1).

The Huntington Beach Fire Department provided a comment letter, dated November 17, 2015, to the Energy Commission outlining the city's waste management code requirements for HBEP (CHB 2015a TN 206751). The Huntington Beach codes are called City Specifications. The project would be required to comply with certain specifications prior to obtaining building permits or start of grading on the project site. Below is a description of the Waste Management City Specifications that apply.

- Due to the underlying oil reserves and possibility of the production of methane gas in native soils, the site and surrounding area has been mapped as being within a Methane Overlay District. Development within a Methane Overlay District must abide by the city of Huntington Beach Methane District Building Permit Requirements, City Specification 429, Methane District Building Permit, would be required. The city of Huntington Beach recommends not building structures over or near abandoned oil wells or hydrocarbon contaminated soil. If abandoned wells can be proven safe and or hydrocarbon contaminated soils conform to Huntington Beach Soil Cleanup Standard 431-92, construction may be allowed at the discretion of the fire chief.
- City Specification 431-21 is the Soil Quality Standard. In an attempt to restore hydrocarbon contaminated soil to a clean condition, meeting the environmental requirements listed within this specification, and to protect the health and safety of the community, the city of Huntington Beach maintains a standard for soil quality.
- City Specification 427 is the General Closure Requirement for Aboveground Hazardous Material Storage Facilities. Closure is required to ensure that no hazardous materials remain at a facility that could create public safety, environmental or health hazards.

Given the Recognized Environmental Concerns and Historical Recognized Environmental Conditions described above, condition of certification **WASTE-1,** ensures that the project site is adequately investigated, characterized and remediated as necessary, when areas of contamination are discovered. Condition of certification **WASTE-1** specifies that the appropriate agencies be contacted and that all the appropriate documentation be provided to the Energy Commission CPM, DTSC, the Huntington Beach Fire Department, and Orange County.

Furthermore, conditions of certification **WASTE-3** and **WASTE-4** address any soil contamination encountered during project demolition and/or construction. **WASTE-3** would require that an experienced and qualified Professional Engineer or Professional Geologist be available for consultation in the event contaminated soil not previously identified is encountered. If contaminated soil is identified, **WASTE-4** would require that the Professional Engineer or Professional Geologist inspect the site, determine what is required to characterize the nature and extent of contamination, and provide a report to the CPM with findings and recommended actions. **WASTE–4** also addresses identification and investigation of any previously unidentified soil or groundwater contamination that may be encountered.

The demolition of HBGS Unit 5 and the fuel tanks and the construction of Block 1 and Block 2 would produce a variety of mixed wastes, such as soil, wood, metal, and concrete, etc. Units 3 and 4 are subject to the Energy Commission's compliance oversight in 00-AFC-13C, and would be included in the cumulative impact analysis. The hazardous waste generated during this phase of the project would consist of asbestos debris, heavy metal dust, used oils, universal wastes, solvents, and empty hazardous waste material containers (HBEP 2012a, § 5.14.4).

Operation and maintenance of the plant and associated facilities would generate a variety of wastes, including a small quantity of hazardous wastes. To control air emissions, the project's turbine units would use selective catalytic reduction and oxidation catalyst equipment and chemicals, which generate both solid and hazardous waste. Waste would be recycled where practical and non-recyclable waste would be deposited in a Class III landfill.

DEMOLITION AND CONSTRUCTION IMPACTS AND MITIGATION

The HBEP facility would generate nonhazardous and hazardous waste that would add to the total waste generated in Orange County. The PTA does not include information on the amount of waste that would be generated by the amended HBEP. The PTA states that the amount of waste to be generated by the project would be slightly less or similar to the licensed HBEP (CEC 2016d). The types and volume of nonhazardous and hazardous wastes generated during demolition and construction waste would be slightly less for the amended HBEP than what was analyzed for the licensed HBEP for the following reasons:

- The licensed HBEP assumed that existing Huntington Beach Generating Station Units 1 and 2 were demolished to their foundations, and the amended HBEP proposes to demolish the existing Units 1 and 2 to the steam turbine, thus resulting in less demolition waste generated (HBEP 2015e, page 5.14-2).

- The amended HBEP consists of one combined-cycle power block and one simple-cycle power block, resulting in less construction waste generated (HBEP 2015e, page 5.14-2).

Staff concurs with this analysis and uses the more conservative estimates of the amount of nonhazardous and hazardous waste generated from the licensed HBEP to determine if the PTA would produce significant impacts.

Waste Management Table 3 provides an estimate of the amount of waste the licensed HBEP would generate.

Waste Management Table 3
Licensed HBEP Waste Totals

	Nonhazardous	Hazardous
Demolition	26,749 tons	1,205 tons
Construction	398 tons	8 tons
Operation	39 tons/year	
Recycle		
concrete	2,350 tons	
metal	22,000 tons	

Source: HBEP 2012a, page 5.14-13

Site preparation, demolition, and construction of the proposed power plant and associated facilities would generate both nonhazardous and hazardous wastes in solid and liquid form. Before demolition and construction can begin, the project owner would be required to develop and implement a C&D Waste Reduction and Recycling Plan, per proposed condition of certification **WASTE-5**.

Nonhazardous Wastes

All non-hazardous wastes would be recycled to the extent possible and non-recyclable wastes would be collected by a licensed hauler and disposed in a solid waste disposal facility, in accordance with Title 14, California Code of Regulations, section 17200 et seq.

Adoption of condition of certification **WASTE-5** would facilitate proper management of project demolition and construction wastes since the city of Huntington Beach maintains a C&D Reduction and Recycling program. Staff proposes condition of certification **WASTE-5** requiring the project owner to develop and implement a C&D Waste Reduction Plan and submit copies of C&D paperwork to the CPM and the city of Huntington Beach. These conditions would require the applicant to identify type, volume, and waste disposal and recycling methods to be used during construction of the facility. Staff believes that compliance with proposed condition of certification **WASTE-5** would assist the applicant's compliance with the CALGreen Building Code requirements.

Nonhazardous liquid wastes would also be generated during construction, including sanitary waste, dust suppression, stormwater drainage, and equipment wash and test water. Sanitary wastes would be collected in portable, self-contained chemical toilets and pumped periodically for disposal at an appropriate facility. Potentially contaminated equipment wash and/or test water would be contained at designated areas, tested to determine if hazardous, and either discharged to the storm water retention basin (if nonhazardous) or transported to an appropriate treatment/disposal facility. Please see the **SOIL AND WATER RESOURCES** section of this document for more information on the management of project wastewater.

Hazardous Wastes

The hazardous waste generated would include: asbestos waste, electrical equipment, used oils, universal wastes, and lead-acid storage batteries (HBEP 2012a page 5.14-13). Demolition of Units 1, 2 and 5, which is the same as the licensed HBEP, would generate 700 tons of asbestos that would be disposed of in a permitted facility (HBEP 2012n, Data Request 71). SCAQMD Rule 1403 requires the owner or operator of a demolition or renovation to submit an Asbestos Demolition or Renovation Operation Plan at least 10 working days before any asbestos stripping or removal work begins. **WASTE-2** requires that the project owner submit the SCAQMD Asbestos Notification Form for review prior to removal and disposal of asbestos. This program ensures there would be no release of asbestos that could impact public health and safety. The generation of hazardous wastes anticipated during construction includes empty hazardous material containers, solvents, waste paint, oil absorbents, used oil, oily rags, batteries, and cleaning wastes. The amount of waste generated would be minor if handled in the manner identified in the AFC (HBEP 2012a, § 5.14.1.2.2).

Should any construction waste management-related enforcement action be taken or initiated by a regulatory agency, the project owner would be required by proposed condition of certification **WASTE-6** to notify the Energy Commission’s CPM whenever the owner becomes aware of any such action.

In the event that construction excavation, grading, or trenching activities for the proposed project encounter potentially contaminated soils and/or specific handling, disposal, and other precautions that may be necessary pursuant to hazardous waste management LORS, staff finds that proposed conditions of certification **WASTE-3** and **WASTE-4** would be adequate to address any soil contamination contingency that may be encountered during construction of the project and would ensure compliance with LORS. Absent any unusual circumstances, staff considers project compliance with LORS to be sufficient to ensure that no significant impacts would occur as a result of project waste management activities.

OPERATION IMPACTS AND MITIGATION

The types and volume of wastes generated during operation of the amended HBEP would be the same or less than what was analyzed for the licensed HBEP. The equipment for power block 1 and 2 is smaller. The PTA consists of one combined-cycle block and one simple-cycle power block. The amended HBEP would operate less than the licensed HBEP (See **AIR QUALITY**). The operations workforce would be reduced from 33 to 23 members (See **SOCIOECONOMICS**). Staff used the more conservative estimates of the amount of nonhazardous and hazardous waste generated from the licensed HBEP to determine if the PTA would produce significant impacts.

The proposed HBEP would generate non-hazardous and hazardous wastes in both solid and liquid forms under normal operating conditions. Before operations can begin, the project owner would be required to develop and implement an Operation Waste Management Plan pursuant to proposed condition of certification **WASTE-7**.

Non-Hazardous Solid Wastes

Waste products include routine maintenance wastes (such as used air filters, spent deionization resins, sand and filter media), as well as domestic and office wastes (such as office paper, newsprint, aluminum cans, plastic, and glass). All non-hazardous wastes would be recycled to the extent possible, and non-recyclable wastes would be regularly transported off site to a local solid waste disposal facility (HBEP 2012a, § 5.14.1.2.3).

Non-hazardous liquid wastes would be generated during facility operation and are discussed in the Soil and Water Resources section of this document.

Hazardous Wastes

The generation of hazardous wastes expected during routine project operation includes used hydraulic fluids, oils, greases, oily filters and rags, spent selective catalytic reduction catalysts, cleaning solutions and solvents, and batteries. In addition, spills and unauthorized releases of hazardous materials or hazardous wastes may generate contaminated soils or materials that may require corrective action and management as hazardous waste. Proper hazardous material handling and good housekeeping practices would help keep spill wastes to a minimum. However, to ensure proper cleanup and management of any contaminated soils or waste materials generated from hazardous materials spills, staff proposes condition of certification **WASTE-8** requiring the project owner/operator to report, clean up, and remediate as necessary, any hazardous materials spills or releases in accordance with all applicable federal, state, and local requirements. More information on hazardous material management, spill reporting, containment, and spill control and countermeasures plan provisions for the project are provided in the **HAZARDOUS MATERIAL MANAGEMENT** section of the FSA.

The amount of hazardous wastes generated during the operation of amended HBEP would be minor, 100 pounds per year, with source reduction and recycling of wastes implemented whenever possible (HBEP 2012a, Table 5.14-4). This would be about the same or slightly less than what was expected from the licensed HBEP. The hazardous wastes would be temporarily stored on site, transported off site by licensed hazardous waste haulers, and recycled or disposed at authorized disposal facilities in accordance with established standards applicable to generators of hazardous waste (Title 22, CCR, §§ 66262.10 et seq.). Should any operations waste management-related enforcement action be taken or initiated by a regulatory agency, the project owner would be required by proposed condition of certification **WASTE-6** to notify the CPM whenever the owner becomes aware of any such action.

IMPACT ON EXISTING WASTE DISPOSAL FACILITIES

Nonhazardous Solid Wastes

Staff used the waste total from the licensed project because it is the most conservative estimate to determine the impacts on waste disposal facilities. Demolition, construction and operation of the amended HBEP would produce the same amount or less than the amount of waste than the licensed project. During demolition, construction and operation of the proposed project, approximately 26,749 tons (59,179 cubic yards), 398 tons (2,653 cubic yards), and 39 tons per year (260 cubic yards per year)[2], respectively, of nonhazardous waste would be generated and recycled or disposed of in a Class III landfill (HBEP 2012 page 5.14-13).

The combined remaining capacity of the two landfills that would be used by the project is 414 million cubic yards. Refer to **Waste Management Table 4**. The total amount of nonhazardous waste generated from project demolition, construction, and operation would contribute less than 1 percent of the available landfill capacity. Staff finds that solid waste disposal generated by the HBEP project could occur without significantly impacting the capacity or remaining life of Orange County landfills.

Waste Management Table 4
Solid Waste Disposal Facilities for HBEP

	Location	Permitted Capacity (Cubic Yards)	Remaining Capacity (Cubic Yards)
Fran Bowerman Sanitary Landfill	Irvine	266,000,000	198,000,000
Olinda Alpha Sanitary Landfill	Brea	148,000,000	47,000,000

Source: HBEP 2012aPage 5.14-11

[2] The volume estimates (cubic yards) for solid/non-hazardous waste are staff generated numbers based on a conversion factor of approximately 906 pounds per cubic yard (taking into account amount of ferrous metal and cement) and 300 pounds per cubic yard for construction waste (HBEP Tables 5.14-1, 5.14-2 and Table 5.14-3). See http://www.calrecycle.ca.gov/lgcentral/library/dsg/apndxi.htm and city of Antioch conversion factors.

Hazardous Wastes

Hazardous wastes generated during demolition, construction, and operation would be recycled to the extent possible and practical. Any wastes that cannot be recycled would be transported off-site to a permitted Class I landfill. Staff determined the impact from the project by using the most conservative numbers, which were the waste numbers from licensed HBEP. It was estimated 8,033 cubic yards of demolition hazardous waste, 53 cubic yards of construction hazardous waste, and less than 100 cubic yards per year of hazardous would be disposed of in a Class I landfill. Two hazardous waste (Class I) disposal facilities are currently accepting waste and could be used to manage HBEP wastes: the Clean Harbors Buttonwillow Landfill in Kern County and the Chemical Waste Management Kettleman Hills Landfill in Kings County. In total, there is a combined excess of 15.5 million cubic yards of remaining hazardous waste disposal capacity at these landfills.

Given the availability of recycling facilities for high volume hazardous wastes such as used oil and solvents, along with the remaining capacity available at Class I disposal facilities, staff concludes that the volume of hazardous waste from the HBEP project requiring off-site disposal would be minor and would therefore not significantly impact the capacity or remaining life of the Class I waste facilities.

The wastes generated by the proposed amended HBEP PTA would incrementally increase the volumes of waste requiring off-site management and disposal at local landfills. However, the HBEP project’s proposed waste management methods and mitigation measures (implementation of source reduction, waste minimization and recycling), along with the proposed conditions of certification discussed below (including compliance with the city of Huntington Beach’s construction and demolition waste recycling and diversion requirements), would ensure that wastes generated by the proposed project would not result in a significant impact to local waste management and disposal facilities.

CUMULATIVE IMPACTS AND MITIGATION

In general, cumulative impacts consist of impacts that are created as a result of the proposed project in combination with impacts from other closely related past, present, or reasonably foreseeable future projects. Cumulative impacts can result from individually minor, but collectively significant, actions taking place over time (Cal. Code Regs., tit. 14, §15355.).

The **Land Use Section Cumulative Impacts Table** lists 26 projects that include transportation, energy, commercial and residential projects. The wastes generated by these projects and the proposed HBEP would incrementally increase the volumes of waste requiring offsite management and disposal at local or regional landfills. One of the waste generating projects in the area will be the Ascon Landfill. The Ascon landfill will generate and dispose of approximately 32,250 cubic feet. The waste from the Ascon landfill would be disposed in an out-of-state Class I landfill (Sayed 2016) therefore there would be no impact on landfills used for disposal of HBEP wastes.

The projects vary in size and there is no data detailing the amount of waste that would be generated from the various projects, however, all residential, commercial and industrial projects would have to comply with Cal Recycle, Mandatory Commercial Recycling, Title 14, Division 7, Chapter 9.1.[3] and Title 24 (CALGreen). The implementation of these regulations would reduce solid waste disposal in the city of Huntington Beach and Orange County. All of the projects listed would be required to recycle 50 to 75 percent of the waste generated from their project, thus minimizing the amount of waste generated from construction and demolition of new and current projects. The project owner estimated that 27,147 tons of solid waste would be generated during demolition and construction of the licensed HBEP. It is estimated that 2,350 tons of recyclable concrete would be generated from removal of the existing foundations and that 22,000 tons of metal would also be recyclable from demolition of the existing Huntington Beach Generating Station Units 1, 2, and 5 (HBEP 2012a page 5.14-6). Orange County landfilled 4,436,932 tons of solid waste in 2014. The amended HBEP's contribution would be less than one percent of the county's waste generation.

Staff has concluded that the HBEP project's proposed waste management methods and mitigation measures (implementation of source reduction, waste minimization and recycling), along with staff's proposed conditions of certification , would ensure that wastes generated by the proposed project would not result in a significant cumulative impact to local waste management and disposal facilities.

CONCLUSIONS AND RECOMMENDATIONS

Management of the waste generated during construction and operation of HBEP would not result in any significant adverse impacts and would comply with applicable waste management laws, ordinances, regulations, and standards, if the measures proposed in the staff analysis are implemented. The implementation of the current conditions of certification for HBEP would mitigate impacts to below significance for the construction and operation of the project.

CONDITIONS OF CERTIFICATION

The existing conditions of certification are adequate to ensure there would be no unmitigated significant impacts. Deleted text is in ~~strikethrough~~ and new text is **<u>bold and underlined</u>**.

WASTE-1 The project owner shall ensure that the HBEP project site is properly characterized and remediated as necessary pursuant to the corrective action plans reviewed by DTSC, the Huntington Beach Fire Department (HBFD) and/or the Orange County Health Care Agency. In no event shall project construction commence in areas requiring characterization and remediation until the CPM determines, with confirmation from the appropriate regulatory agency, that all necessary remediation has been accomplished.

[3] Regulatory requirements; Businesses and public entities that generate four or more cubic yards of solid waste per week, and multifamily residential dwellings that have five units or more, take action to reuse, recycle, compost or otherwise divert commercial solid waste from disposal.

Prior to and during grading and construction, discovery of additional soil contamination not previously identified or already included in corrective action plans, work plans, or closure plans must be reported to the CPM, DTSC, and the HBFD immediately.

Verification: At least 45 days prior to remediation the project owner shall submit to the CPM for approval copies of remediation documentation, such as, but not limited to, soil sample results, work plans, and agreements regarding the corrective action plan requirements and activities at the project site. Pertinent correspondence such as, but not limited to, soil sample results, work plans, agreements, and authorizations involving DTSC, the HBFD, and/or (if applicable) the Orange County Health Care Agency regarding the corrective action plan requirements and activities at the project site will be provided to the CPM within 10 days of receipt.

At least 15 days prior to the start of site mobilization, the project owner shall provide to the CPM written notice from the appropriate regulatory agency that the HBEP site has been investigated and remediated as necessary in accordance with the corrective action plan.

If soil contamination not previously identified or already included in corrective action plans, work plans or closure plans is encountered prior to or during grading the project owner shall notify the CPM and DTSC, revise the approved work plan and submit it for concurrent CPM, HBFD, and DTSC review within 30 days after contamination is identified. Comments received within 30 days from all parties will be incorporated and provided to DTSC for approval.

WASTE-2 Prior to demolition of existing structures associated with Units 1, 2, and 5, the project owner shall complete and submit a copy of a SCAQMD Asbestos Demolition Notification Form to the CPM and the SCAQMD for approval. After receiving approval, the project owner shall remove all Asbestos Containing Material (ACM) from the site prior to demolition.

Verification: No less than sixty (60) days prior to commencement of structure demolition, the project owner shall provide the Asbestos Demolition Notification Form to the CPM for review and approval. The project owner shall inform the CPM via the monthly compliance report, of the data when all ACM is removed from the site.

WASTE-3 The project owner shall provide the resume of an experienced and qualified professional engineer or professional geologist, who shall be available for consultation during site characterization (if needed), demolition, excavation, and grading activities, to the CPM for review and approval. The resume shall show experience in remedial investigation and feasibility studies.

The professional engineer or professional geologist shall be given full authority by the project owner to oversee any earth moving activities that have the potential to disturb contaminated soil.

Verification: At least 30 days prior to the start of site mobilization, the project owner shall submit the resume of the professional engineer or professional geologist to the CPM for review and approval.

WASTE-4 If potentially contaminated soil is identified during site characterization, demolition, excavation, or grading at either the proposed site or linear facilities, as evidenced by discoloration, odor, detection by handheld instruments, or other signs, the professional engineer or professional geologist shall inspect the site, determine the need for sampling to confirm the nature and extent of contamination, and provide a written report to the project owner, representatives of Department of Toxic Substances Control, and the CPM stating the recommended course of action.

Depending on the nature and extent of contamination, the professional engineer or professional geologist shall have the authority to temporarily suspend construction activity at that location for the protection of workers or the public. If, in the opinion of the professional engineer or professional geologist, significant remediation may be required, the project owner shall contact the CPM and representatives of the Department of Toxic Substances Control for guidance and possible oversight.

Verification: The project owner shall submit any final reports filed by the professional engineer or professional geologist to the CPM within 5 days of their receipt. The project owner shall notify the CPM within 24 hours of any orders issued to halt construction.

WASTE-5 The project owner shall prepare a ~~Construction Waste Management Plan~~ **Construction and Demolition (C&D) Debris Waste Reduction and Recycling Plan** for all wastes generated during **demolition and** construction of the facility and shall submit the plan to the CPM for review and approval. The plan shall contain, at a minimum, the following:

- A description of all construction waste streams, including projections of frequency, amounts generated, and hazard classifications;
- Management methods to be used for each waste stream, including temporary on-site storage, housekeeping and best management practices to be employed, treatment methods and companies providing treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/source reduction plans.
- A method for collecting weigh tickets or other methods for verifying the volume of transported and or location of waste disposal; and,
- A method for reporting to demonstrate project compliance with construction waste diversion requirements of 50 percent pursuant to the CALGreen Code and Construction and Orange County Construction & Demolition Recycling and Reuse Program.

Verification: The project owner shall submit the **C&D Debris Waste Reduction and Recycling Plan** ~~Construction Waste Management Plan~~ to the CPM **and the city of Huntington Beach Department of Planning and Building** for approval no less than 30 days prior to the initiation of **demolition** and construction activities at the site.

The project owner shall also document in each monthly compliance report (MCR) the actual volume of wastes generated and the waste management methods used during the year; provide a comparison of the actual waste generation and management methods used to those proposed in the original Construction Waste Management Plan; and update the Construction Waste Management Plan, as necessary, to address current waste generation and management practices.

WASTE-6 Upon becoming aware of any impending waste management-related enforcement action by any local, state, or federal authority, the project owner shall notify the CPM of any such action taken or proposed to be taken against the project itself, or against any waste hauler or disposal facility or treatment operator with which the owner contracts.

Verification: The project owner shall notify the CPM in writing within 10 days of becoming aware of an impending enforcement action. The CPM shall notify the project owner of any changes that will be required in the way project-related wastes are managed.

WASTE-7 The project owner shall prepare an Operation Waste Management Plan for all wastes generated during operation of the facility and shall submit the plan to the CPM for review and approval. The plan shall contain, at a minimum, the following:

- A detailed description of all operation and maintenance waste streams, including projections of amounts to be generated, frequency of generation, and waste hazard classifications;
- Management methods to be used for each waste stream, including temporary on-site storage, housekeeping and best management practices to be employed, treatment methods and companies providing treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/source reduction plans;
- Information and summary records of conversations with the local Certified Unified Program Agency and the Department of Toxic Substances Control regarding any waste management requirements necessary for project activities. Copies of all required waste management permits, notices, and/or authorizations shall be included in the plan and updated as necessary;
- A detailed description of how facility wastes will be managed and any contingency plans to be employed, in the event of an unplanned closure or planned temporary facility closure; and
- A detailed description of how facility wastes will be managed and disposed upon closure of the facility.

Verification: The project owner shall submit the Operation Waste Management Plan to the CPM for approval no less than 30 days prior to the start of project operation. The project owner shall submit any required revisions to the CPM within 20 days of notification from the CPM that revisions are necessary.

The project owner shall also document in each Annual Compliance Report the actual volume of wastes generated and the waste management methods used during the year; provide a comparison of the actual waste generation and management methods used to those proposed in the original Operation Waste Management Plan; and update the Operation Waste Management Plan as necessary to address current waste generation and management practices.

WASTE-8 The project owner shall ensure that all spills or releases of hazardous substances, materials, or waste are reported, cleaned up, and remediated as necessary, in accordance with all applicable federal, state, and local requirements.

Verification: The project owner shall document all unauthorized releases and spills of hazardous substances, materials, or wastes that occur on the project property or related pipeline and transmission corridors. The documentation shall include, at a minimum, the following information: location of release; date and time of release; reason for release; volume released; amount of contaminated soil/material generated; how release was managed and material cleaned up; if the release was reported; to whom the release was reported; release corrective action and cleanup requirements placed by regulating agencies; level of cleanup achieved and actions taken to prevent a similar release or spill; and disposition of any hazardous wastes and/or contaminated soils and materials that may have been generated by the release. Copies of the unauthorized spill documentation shall be provided to the CPM within 30 days of the date the release was discovered.

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HUNTINGTON BEACH ENERGY PROJECT (12-AFC-2C)
Petition to Amend Final Commission Decision
WORKER SAFETY AND FIRE PROTECTION

Brett Fooks, PE and Geoff Lesh, PE

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) the Huntington Beach Energy Project (HBEP) proposes to modify the project which will not necessitate modification to the existing set of Worker Safety and Fire Protection conditions of certification. Similar to the conclusions in the project's licensed Huntington Beach Energy Project 2014 Energy Commission Final Decision (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 Decision is necessary for Worker Safety and Fire Protection. The committee may rely upon the environmental analysis and conclusions of the Decision with regards to Worker Safety and Fire Protection and does not need to re-analyze them.

Staff determined that the laws, ordinances, regulations, and standards (LORS) applicable to the project remain the same since the Decision. 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 and Fire Protection conditions of certification. As discussed in detail in the Project Description section, the amended HBEP would be a natural gas fired, combined-cycle and simple-cycle, air-cooled electrical generating facility on the site of the existing Huntington Beach Generating Station in Huntington Beach, California.

SUMMARY OF THE DECISION

The Commission's Decision 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 with all applicable LORS and would not result in any unmitigated significant impacts.

Worker Safety and Fire Protection Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Federal	
Title 29 U.S. Code (USC) section 651 et seq (Occupational Safety and Health Act of 1970)	This act mandates safety requirements in the workplace with the purpose of "[assuring] so far as possible every working man and woman in the nation safe and healthful working conditions and to preserve our human resources" (29 USC § 651).
Title 29 Code of Federal Regulation (CFR) sections 1910.1 to 1910.1500 (Occupational Safety and Health Administration Safety and Health Regulations)	These sections define the procedures for promulgating regulations and conducting inspections to implement and enforce safety and health procedures to protect workers, particularly in the industrial sector.
29 CFR sections 1952.170 to 1952.175	These sections provide federal approval of California's plan for enforcement of its own Safety and Health requirements, in lieu of most of the federal requirements found in 29 CFR sections 1910.1 to 1910.1500.
State	
Title 8 California Code of Regulations (Cal Code Regs.) all applicable sections (Cal/OSHA regulations)	These sections require that all employers follow these regulations as they pertain to the work involved. This includes regulations pertaining to safety matters during construction, commissioning, and operations of power plants, as well as safety around electrical components, fire safety, and hazardous materials use, storage, and handling.
24 Cal Code Regs. section 3, et seq.	This section incorporates the current addition of the Uniform Building Code.
Health and Safety Code section 25500, et seq.	This section presents Risk Management Plan requirements for threshold quantity of listed acutely hazardous materials at a facility.
Health and Safety Code sections 25500 to 25541	These sections require a Hazardous Material Business Plan detailing emergency response plans for hazardous materials emergency at a facility.
Local (or locally enforced)	
California Fire Code 2010	The fire code contains general provisions for fire safety, including requirements for proper storage and handling of hazardous materials and listing of the information needed by emergency response personnel. Enforced by the Huntington Beach Fire Department.
City of Huntington Beach Municipal Code, Chapter 17.56	City of Huntington Beach Fire Code: The City of Huntington Beach has adopted the California Fire Code and has adopted several ordinances which amend it. l
City of Huntington Beach Municipal Code Section 17.58	Develop and implement safety management plans as required by CA H&SC Sections 25500-25520. Administered by the Huntington Beach Fire Department
City of Huntington Beach Fire Department City Specifications	Various Huntington Beach Fire Department City Specifications (numbered 401 through 434) may be found at: http://www.huntingtonbeachca.gov/government/departments/Fire/fire_prevention_code_enforcement/fire_dept_city_specifications.cfm
NFPA 56 (adopted 2012)	NFPA 56 is the Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems.
National Fire Protection Association (NFPA) standards	These standards provide specifications and requirements for fire safety, including the design, installation, and maintenance of fire protection equipment. Enforced by the Huntington Beach Fire Department.

There have been no changes in the applicable LORS to the amended HBEP since the Decision for worker safety/fire protection and the project would comply with all applicable LORS.

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 amended HBEP would be the same or less than significant with the proposed mitigation as 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* by proposing a new condition of certification.

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 delegate chief building official (DCBO) is instructed through the Energy Commission's DCBO 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 HBEP. In any situations where both NFPA 850 and other state or local LORS have application, the more restrictive shall apply. 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>** and deletions are shown in ~~strikethrough~~.

WORKER SAFETY-1 PROJECT CONSTRUCTION SAFETY AND HEALTH PROGRAM

The project owner shall submit to the compliance project manager (CPM) a copy of the Project Construction Safety and Health Program containing the following:

- a Construction Personal Protective Equipment Program;
- a Construction Exposure Monitoring Program;
- a Construction Injury and Illness Prevention Program;
- a Construction Emergency Action Plan; and
- a Construction Fire Prevention Plan.

The Personal Protective Equipment Program, the Exposure Monitoring Program, and the Injury and Illness Prevention Program shall be submitted to the CPM for review and approval concerning compliance of the program with all applicable safety orders. The Construction Emergency Action Plan and the Fire Prevention Plan shall be submitted to the Huntington Beach 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 copy of a letter~~ to the CPM **a copy of the letter** from the Huntington Beach Fire Department stating the fire department's ~~timely~~ comments**, if and when any are received,** on the Construction Fire Prevention Plan and Emergency Action Plan.

WORKER SAFETY-2 PROJECT OPERATIONS AND MAINTENANCE SAFETY AND HEALTH PROGRAM

The project owner shall submit to the CPM a copy of the Project Operations and Maintenance Safety and Health Program containing the following:

- an Operation Injury and Illness Prevention Plan;
- an Emergency Action Plan;
- Hazardous Materials Management Program;
- Fire Prevention Plan (8 Cal Code Regs. § 3221); and
- Personal Protective Equipment Program (8 Cal Code Regs, §§ 3401—3411).

The Operation Injury and Illness Prevention Plan, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted to the CPM for review and approval concerning compliance of the programs with all applicable safety orders. The Fire Prevention Plan and the Emergency Action Plan shall also be submitted to the Huntington Beach Fire Department for review and comment.

Verification: At least 30 days prior to the start of first-fire or commissioning, the project owner shall submit to the CPM for approval a copy of the Project Operations and Maintenance Safety and Health Program. The project owner shall provide a copy of a letter to the CPM from the Huntington Beach Fire Department stating the fire department's ~~timely~~ comments**, if and when any comments are received,** on the Operations Fire Prevention Plan and Emergency Action Plan.

WORKER SAFETY-3 CONSTRUCTION SAFETY SUPERVISOR

The project owner shall assign a site Construction Safety Supervisor (CSS) who, by way of training and/or experience, ~~is~~ has knowledge of power plant construction activities and relevant laws, ordinances, regulations, and standards; is capable of identifying workplace hazards relating to the construction activities; and has authority to take appropriate action to assure compliance and mitigate hazards. The CSS shall:

- have overall authority for coordination and implementation of all occupational safety and health practices, policies, and programs;
- assure that the safety program for the project complies with Cal/OSHA and federal regulations related to power plant projects;
- assure that all construction and commissioning workers and supervisors receive adequate safety training;
- complete accident and safety-related incident investigations and emergency response reports for injuries and inform the CPM of safety-related incidents; and
- assure that all the plans identified in conditions of certification **WORKER SAFETY-1** and **-2** are implemented.

Verification: At least 60 days prior to the start of site mobilization, the project owner shall submit the name and contact information for the CSS to the CPM for review and approval. The contact information of any replacement CSS shall be submitted to the CPM within one business day.

- The CSS shall submit, in the Monthly Compliance Report, a monthly safety inspection report to include:
- record of all employees trained for that month (all records shall be kept on site for the duration of the project);
- summary report of safety management actions and safety-related incidents that occurred during the month;
- report of any continuing or unresolved situations and incidents that may pose danger to life or health; and
- report of accidents and injuries that occurred during the month.

WORKER SAFETY-4 SAFETY MONITOR

The project owner shall, through an agreement with the Chief Building Official (CBO), obtain and pay for the services of a Safety Monitor. The services of the Safety Monitor shall be in addition to other work performed by the CBO. The Safety Monitor shall be selected by and report directly to the CBO and will be responsible for verifying that the Construction Safety Supervisor, as required in condition of certification **WORKER SAFETY-3**, implements all appropriate Cal/OSHA and Energy Commission safety requirements. The Safety Monitor shall have full access to the project site to conduct on-site (including linear facilities) safety inspections at intervals necessary to fulfill those responsibilities.

Verification: At least 60 days prior to the start of construction, the project owner shall provide proof of its agreement to fund the Safety Monitor services to the CPM for review and approval.

WORKER SAFETY-5 AUTOMATIC EXTERNAL DEFIBRILLATOR

The project owner shall ensure that a portable automatic external defibrillator (AED) is located and properly maintained and functioning on site during all demolition, construction, and operations. The project owner shall prepare and implement a training program on the use of the AED. The training program shall be submitted to the CPM for review and approval. During construction and commissioning, the following persons shall be trained in its use and shall be on site whenever the workers that they supervise are on site: the Construction Project Manager or delegate, the Construction Safety Supervisor or delegate, and all shift foremen. During operations, all power plant employees shall be trained in its use.

Verification: At least 60 days prior to the start of site mobilization, the project owner shall submit the AED training program to the CPM for review and approval. The project owner shall also submit proof that a portable automatic external defibrillator (AED) exists on site in the Monthly Compliance Report and the Annual Compliance Report.

WORKER SAFETY-6 EMERGENCY ACCESS PLAN

The project owner shall prepare an Emergency Access Plan that shows all of the following: (1) a 26-foot wide fire lane that will provide a continuous loop around HBEP Block 1; (2) a 26-foot wide fire lane that will provide a continuous loop around HBEP Block 2; (3) a 26-foot wide fire lane from the HBEP main entrance to the continuous loops referenced in (1) and (2) above; and (4) a 26-foot wide fire lane from a secondary access point to the continuous loops referenced in (1) and (2) above. Both access lanes shall connect to a public street. Corners must allow for clear travel of a minimum 17-foot inner radius and 45-foot outer radius (radius must be concentric). The fire lanes shall be designed and maintained to support the imposed loads of fire apparatus (75,000 lbs. load/12,000 point load) and shall be surfaced to provide all-weather driving capabilities. Fire lane signage shall be provided as per City of Huntington Beach Specification #415. The 26-foot wide fire lanes shall meet the applicable requirements of the California Fire Code, City of

Huntington Beach Municipal Code Chapter 17.56 - Huntington Beach Fire Code, and the Huntington Beach Fire Department City Specifications.

Verification: At least 60 days prior to the start of construction of any structures or components listed in the CBO-approved master drawing and master specification list, or within a timeframe approved by the CPM, the project owner shall submit the Emergency Access Plan to the ~~C~~**Huntington Beach**~~ity~~ Fire Department for review and timely comment, and to the CPM and CBO for review and approval.

WORKER SAFETY-7 NFPA 850: RECOMMENDED PRACTICE FOR FIRE PROTECTION FOR ELECTRIC GENERATING PLANTS

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 as the minimum level of fire protection. The project owner shall interpret and adhere to all applicable NFPA 850 recommended provisions and actions stating "should" as "shall" In any situations where both NFPA 850 and the state or local LORS have application, the more restrictive shall apply.

Verification: The project owner shall ensure that the project adheres to all applicable provisions of NFPA 850. At least 60 days prior to the start of construction of the fire protection system, the project owner shall provide all fire protection system specifications and drawings to the Huntington Beach Fire Department for review and comment, to the CPM for review and approval, and to the DCBO for plan check and construction inspection.

REFERENCES

HBEP 2012a - AES Southland Development, LLC / Stephen O'Kane (TN 66003). Application for Certification (AFC), Volume I & II, dated, 06/27/2012. Submitted to CEC/Dockets on 06/27/2012.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

Engineering Assessment

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)

Petition to Amend Final Commission Decision

FACILITY DESIGN

Shahab Khoshmashrab

SUMMARY OF CONCLUSIONS

Similar to the conclusions in the Decision for the Huntington Beach Energy Project (HBEP), the amended HBEP project would create no significant impacts related to facility design. 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 Decision is necessary for Facility Design. The Committee may rely upon the analysis and conclusions of the Decision with regards to Facility Design and does not need to re-analyze them.

Staff concludes that the amended project would comply with applicable engineering laws, ordinances, regulations, and standards (LORS). The same Facility Design conditions of certification contained in the Decision, and presented below, would ensure compliance with these LORS.

INTRODUCTION

Staff has reviewed the 2014 Energy Commission Final Decision (Decision) (CEC 2014bb) and analyzed the changes to the licensed HBEP (HBEP 2015a), which include revising the two, three-on-one combined-cycle power blocks totaling 939 megawatts (MW), to a single two-on-one combined-cycle power block and two simple-cycle gas turbine units, totaling 844 MW. 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 Decision.

SUMMARY OF THE DECISION

The Decision adopted the staff's conditions of certification that establish a design review and construction inspection process to ensure compliance with applicable engineering LORS and to confirm the project, including the architectural visual enhancements (the proposed surfboards or wave form walls), will be built in a manner to ensure life safety. Conditions of certification **GEN-2** contained in the Decision requires that the architectural visual enhancements be designed and constructed in compliance with the California Building Code (CBC).

In addition, those conditions of certification specify the roles, qualifications, and responsibilities of engineering personnel who will oversee project design and construction. They further require project design approval and construction inspection by the Energy Commission's delegate chief building official (CBO) to ensure compliance with those conditions of certification and the LORS.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

No LORS applicable to the project have changed since the Decision was published in 2014. The proposed amendment would not trigger new LORS that may not have been applicable to the original project. **Facility Design Table 1**, listing key engineering LORS applicable to Facility Design as described in the Decision, is shown below.

Facility Design Table 1: Key Engineering LORS

Applicable LORS	Description
Federal	Title 29 Code of Federal Regulations (CFR), Part 1910, Occupational Safety and Health standards
State	2013 (or the latest edition in effect) California Building Standards Code (also known as Title 24, California Code of Regulations)
Local	City of Huntington Beach regulations and ordinances
General	American National Standards Institute American Society of Mechanical Engineers American Welding Society American Society for Testing and Materials

The complete list of LORS applicable to each engineering discipline (civil, structural, mechanical, and electrical) is described in Appendix 2C of the Application for Certification for HBEP (CEC 2014bb, p. 3.1-1).

ANALYSIS

The modifications proposed in the amendment would not affect Facility Design since the same LORS and design review and inspection process apply to the amended HBEP as those in the Decision. Also compared to the Decision, the roles, qualifications, and responsibilities of engineering personnel who would oversee project design and construction are unchanged.

The amendment proposes to replace the architectural surfboards and wave forms with visual screening walls as described in the Visual Resources section of this document. Similar to the surfboards and wave forms, the design and construction of these screening walls must comply with the structural requirements of the CBC, and thus, the reference to the architectural visual enhancement in conditions of certification **GEN-2** remains.

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.

- 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

Similar to the conclusions in the Decision for the HBEP, the amended project would comply with applicable engineering LORS. Implementation of the existing Facility Design conditions of certification contained in the Decision would ensure the amended project's compliance with applicable engineering LORS.

PROPOSED CONDITIONS OF CERTIFICATION

No changes to the Facility Design conditions of certification are needed.

GEN-1 The project owner shall design, construct, and inspect the project in accordance with this Decision and the 2013 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 the edition that has been adopted by the California Building Standards Commission and published at least 180 days previously). The project owner shall ensure that all the provisions of the above applicable codes are enforced during the construction, addition, alteration, moving, demolition, repair, or maintenance of the completed facility. All transmission facilities (lines, switchyards, switching stations and substations) are covered in the conditions of certification in the Transmission System Engineering section of this document.

In the event that the initial engineering designs are submitted to the CBO when the successor to the 2013 CBSC is in effect, the 2013 CBSC provisions shall be replaced with the applicable successor provisions. Where, in any specific case, different sections of the code specify different materials, methods of construction or other requirements, the most restrictive shall govern. Where there is a conflict between a general requirement and a specific requirement, the specific requirement shall govern.

The project owner shall ensure that all contracts with contractors, subcontractors, and suppliers clearly specify that all work performed and materials supplied comply with the codes listed above.

Verification: Within 30 days following receipt of the certificate of occupancy, the project owner shall submit to the CPM a statement of verification, signed by the responsible design engineer, attesting that all designs, construction, installation, and inspection requirements of the applicable LORS and the Energy Commission's decision have been met in the area of facility design. The project owner shall provide the CPM a copy of the certificate of occupancy within 30 days of receipt from the CBO.

Once the certificate of occupancy has been issued, the project owner shall inform the CPM at least 30 days prior to any construction, addition, alteration, moving, demolition, repair, or maintenance to be performed on any portion(s) of the completed facility that requires CBO approval for compliance with the above codes. The CPM will then determine if the CBO needs to approve the work.

GEN-2 Before submitting the initial engineering designs for CBO review, the project owner shall furnish the CPM and the CBO with a schedule of facility design submittals, and master drawings and master specifications list. The master drawings and master specifications list shall contain a list of proposed submittal packages of designs, calculations, and specifications for major structures, systems, and equipment, including the architectural visual enhancement specified in the Visual Resources section. Major structures, systems, and equipment are structures and their associated components or equipment that are necessary for power production, costly or time consuming to repair or replace, are used for the storage, containment, or handling of hazardous or toxic materials, or could become potential health and safety hazards if not constructed according to applicable engineering LORS. The schedule shall contain the date of each submittal to the CBO. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM upon request.

Verification: At least 60 days (or a project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO and to the CPM the schedule, and the master drawings and master specifications list of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures, systems, equipment, and the architectural enhancement features defined above in conditions of certification **GEN-2**. Major structures and equipment shall be added to or deleted from the list only with CPM approval. The project owner shall provide schedule updates in the monthly compliance report.

GEN-3 The project owner shall make payments to the CBO for design review, plan checks, and construction inspections, based upon a reasonable fee schedule to be negotiated between the project owner and the CBO. These fees may be consistent with the fees listed in the 2013 CBC, adjusted for inflation and other appropriate adjustments; may be based on the value of the facilities reviewed; may be based on hourly rates; or may be otherwise agreed upon by the project owner and the CBO.

Verification: The project owner shall make the required payments to the CBO in accordance with the agreement between the project owner and the CBO. The project owner shall send a copy of the CBO's receipt of payment to the CPM in the next monthly compliance report indicating that applicable fees have been paid.

GEN-4 Prior to the start of rough grading, the project owner shall assign a California-registered architect, or a structural or civil engineer, as the resident engineer (RE) in charge of the project. All transmission facilities (lines, switchyards, switching stations, and substations) are addressed in the conditions of certification in the Transmission System Engineering section of this document.

The RE may delegate responsibility for portions of the project to other registered engineers. Registered mechanical and electrical engineers may be delegated responsibility for mechanical and electrical portions of the project, respectively. A project may be divided into parts, provided that each part is clearly defined as a distinct unit. Separate assignments of general responsibility may be made for each designated part.

The RE shall:

1. Monitor progress of construction work requiring CBO design review and inspection to ensure compliance with LORS;

2. Ensure that construction of all facilities subject to CBO design review and inspection conforms in every material respect to applicable LORS, these conditions of certification, approved plans, and specifications;

3. Prepare documents to initiate changes in approved drawings and specifications when either directed by the project owner or as required by the conditions of the project;

4. Be responsible for providing project inspectors and testing agencies with complete and up-to-date sets of stamped drawings, plans, specifications, and any other required documents;

5. Be responsible for the timely submittal of construction progress reports to the CBO from the project inspectors, the contractor, and other engineers who have been delegated responsibility for portions of the project; and

6. Be responsible for notifying the CBO of corrective action or the disposition of items noted on laboratory reports or other tests when they do not conform to approved plans and specifications.

7. Include the results of any dewatering mitigation measures identified during the scope of the study conducted pursuant to conditions of certification **GEO-1**.

The resident engineer (or his delegate) must be located at the project site, or be available at the project site within a reasonable period of time, during any hours in which construction takes place.

The RE shall have the authority to halt construction and to require changes or remedial work if the work does not meet requirements.

If the RE or the delegated engineers are reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the resume and registration number of the RE and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the RE and other delegated engineer(s) within five days of the approval.

If the RE or the delegated engineer(s) is subsequently reassigned or replaced, the project owner has five days to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-5 Prior to the start of rough grading, the project owner shall assign at least one of each of the following California registered engineers to the project: a civil engineer; a soils, geotechnical, or civil engineer experienced and knowledgeable in the practice of soils engineering; and an engineering geologist. Prior to the start of construction, the project owner shall assign at least one of each of the following California registered engineers to the project: a design engineer who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; a mechanical engineer; and an electrical engineer. (California Business and Professions Code section 6704 et seq., and sections 6730, 6731 and 6736 require state registration to practice as a civil engineer or structural engineer in California). All transmission facilities (lines, switchyards, switching stations, and substations) are handled in the conditions of certification in the Transmission System Engineering section of this document.

The tasks performed by the civil, mechanical, electrical, or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (for example, proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer.

The project owner shall submit, to the CBO for review and approval, the names, qualifications, and registration numbers of all responsible engineers assigned to the project.

If any one of the designated responsible engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned responsible engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

A. The civil engineer shall:

   1. Review the foundation investigations, geotechnical, or soils reports prepared by the soils engineer, the geotechnical engineer, or by a civil engineer experienced and knowledgeable in the practice of soils engineering;

   2. Design (or be responsible for the design of), stamp, and sign all plans, calculations, and specifications for proposed site work, civil works, and related facilities requiring design review and inspection by the CBO. At a minimum, these include: grading, site preparation, excavation, compaction, construction of secondary containment, foundations, erosion and sedimentation control structures, drainage facilities, underground utilities, culverts, site access roads and sanitary sewer systems; and

   3. Provide consultation to the RE during the construction phase of the project and recommend changes in the design of the civil works facilities and changes to the construction procedures.

B. The soils engineer, geotechnical engineer, or civil engineer experienced and knowledgeable in the practice of soils engineering, shall:

   1. Review all the engineering geology reports;

   2. Prepare the foundation investigations, geotechnical, or soils reports containing field exploration reports, laboratory tests, and engineering analysis detailing the nature and extent of the soils that could be susceptible to liquefaction, rapid settlement or collapse when saturated under load;

   3. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with requirements set forth in the 2013 CBC (depending on the site conditions, this may be the responsibility of either the soils engineer, the engineering geologist, or both); and

   4. Recommend field changes to the civil engineer and RE.

5. This engineer shall be authorized to halt earthwork and to require changes if site conditions are unsafe or do not conform to the predicted conditions used as the basis for design of earthwork or foundations.

C. The engineering geologist shall:

1. Review all the engineering geology reports and prepare a final soils grading report; and

2. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 2013 CBC (depending on the site conditions, this may be the responsibility of either the soils engineer, the engineering geologist, or both).

D. The design engineer shall:

1. Be directly responsible for the design of the proposed structures and equipment supports;

2. Provide consultation to the RE during design and construction of the project;

3. Monitor construction progress to ensure compliance with engineering LORS;

4. Evaluate and recommend necessary changes in design; and

5. Prepare and sign all major building plans, specifications, and calculations.

E. The mechanical engineer shall be responsible for, and sign and stamp a statement with, each mechanical submittal to the CBO, stating that the proposed final design plans, specifications, and calculations conform to all of the mechanical engineering design requirements set forth in the Energy Commission’s decision.

F. The electrical engineer shall:

1. Be responsible for the electrical design of the project; and

2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible civil engineer, soils (geotechnical) engineer and engineering geologist assigned to the project.

At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of construction, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible design engineer, mechanical engineer, and electrical engineer assigned to the project.

The project owner shall notify the CPM of the CBO's approvals of the responsible engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-6 Prior to the start of an activity requiring special inspection, including prefabricated assemblies, the project owner shall assign to the project qualified and certified special inspector(s) who shall be responsible for the special inspections required by the 2013 CBC. All transmission facilities (lines, switchyards, switching stations, and substations) are handled in conditions of certification in the Transmission System Engineering section of this document.

A certified weld inspector, certified by the American Welding Society (AWS), and/or American Society of Mechanical Engineers (ASME) as applicable, shall inspect welding performed on-site requiring special inspection (including structural, piping, tanks and pressure vessels).

The special inspector shall:

1. Be a qualified person who shall demonstrate competence, to the satisfaction of the CBO, for inspection of the particular type of construction requiring special or continuous inspection;

2. Inspect the work assigned for conformance with the approved design drawings and specifications;

3. Furnish inspection reports to the CBO and RE. All discrepancies shall be brought to the immediate attention of the RE for correction, then, if uncorrected, to the CBO and the CPM for corrective action; and

4. Submit a final signed report to the RE, CBO, and CPM, stating whether the work requiring special inspection was, to the best of the inspector's knowledge, in conformance with the approved plans, specifications, and other provisions of the applicable edition of the CBC.

Verification: At least 15 days (or project owner- and CBO-approved alternative time frame) prior to the start of an activity requiring special inspection, the project owner shall submit to the CBO for review and approval, with a copy to the CPM, the name(s) and qualifications of the certified weld inspector(s), or other certified special inspector(s) assigned to the project to perform one or more of the duties set forth above. The project owner shall also submit to the CPM a copy of the CBO's approval of the qualifications of all special inspectors in the next monthly compliance report.

If the special inspector is subsequently reassigned or replaced, the project owner has five days in which to submit the name and qualifications of the newly assigned special inspector to the CBO for approval. The project owner shall notify the CPM of the CBO's approval of the newly assigned inspector within five days of the approval.

GEN-7 If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend required corrective actions. The discrepancy documentation shall be submitted to the CBO for review and approval. The discrepancy documentation shall reference this conditions of certification and, if appropriate, applicable sections of the CBC and/or other LORS.

Verification: The project owner shall transmit a copy of the CBO's approval of any corrective action taken to resolve a discrepancy to the CPM in the next monthly compliance report. If any corrective action is disapproved, the project owner shall advise the CPM, within five days, of the reason for disapproval and the revised corrective action to obtain CBO's approval.

GEN-8 The project owner shall obtain the CBO's final approval of all completed work that has undergone CBO design review and approval. The project owner shall request the CBO to inspect the completed structure and review the submitted documents. The project owner shall notify the CPM after obtaining the CBO's final approval. The project owner shall retain one set of approved engineering plans, specifications, and calculations (including all approved changes) at the project site or at another accessible location during the operating life of the project. Electronic copies of the approved plans, specifications, calculations, and marked-up as-builts shall be provided to the CBO for retention by the CPM.

Verification: Within 15 days of the completion of any work, the project owner shall submit to the CBO, with a copy to the CPM in the next monthly compliance report, (a) a written notice that the completed work is ready for final inspection, and (b) a signed statement that the work conforms to the final approved plans. After storing the final approved engineering plans, specifications, and calculations described above, the project owner shall submit to the CPM a letter stating both that the above documents have been stored and the storage location of those documents.

Within 90 days of the completion of construction, the project owner shall provide to the CBO three sets of electronic copies of the above documents at the project owner's expense. These are to be provided in the form of "read only" (Adobe .pdf 6.0 or newer version) files, with restricted (password-protected) printing privileges, on archive quality compact discs.

GEN-9: NO SHORELINE PROTECTIVE DEVICE.

In the event that the approved development, including any future improvements, is threatened with damage or destruction from coastal hazards, or is damaged or destroyed by coastal hazards, protective structures (including but not limited to seawalls, revetments, groins, deep piers/caissons etc.) shall be prohibited. By acceptance of the CEC approval, the project owner waives any right to construct such protective structures, including any that may exist under Public Resources Code Section 30235.

CIVIL-1 The project owner shall submit to the CBO for review and approval the following:

1. Design of the proposed drainage structures and the grading plan;
2. An erosion and sedimentation control plan;
3. A construction storm water pollution prevention plan (SWPPP);
4. Related calculations and specifications, signed and stamped by the responsible civil engineer; and
5. Soils, geotechnical, or foundation investigations reports required by the 2013 CBC.

<u>Verification:</u> At least 15 days (or project owner- and CBO-approved alternative time frame) prior to the start of site grading the project owner shall submit the documents described above to the CBO for design review and approval. In the next monthly compliance report following the CBO's approval, the project owner shall submit a written statement certifying that the documents have been approved by the CBO.

CIVIL-2 The resident engineer shall, if appropriate, stop all earthwork and construction in the affected areas when the responsible soils engineer, geotechnical engineer, or the civil engineer experienced and knowledgeable in the practice of soils engineering identifies unforeseen adverse soil or geologic conditions. The project owner shall submit modified plans, specifications, and calculations to the CBO based on these new conditions. The project owner shall obtain approval from the CBO before resuming earthwork and construction in the affected area.

<u>Verification:</u> 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 2013 CBC. All plant site-grading operations, for which a grading permit is required, shall be subject to inspection by the CBO.

If, in the course of inspection, it is discovered that the work is not being performed in accordance with the approved plans, the discrepancies shall be reported immediately to the resident engineer, the CBO, and the CPM. The project owner shall prepare a written report, with copies to the CBO and the CPM, detailing all discrepancies, non-compliance items, and the proposed corrective action.

Verification: Within five days of the discovery of any discrepancies, the resident engineer shall transmit to the CBO and the CPM a non-conformance report (NCR), and the proposed corrective action for review and approval. Within five days of resolution of the NCR, the project owner shall submit the details of the corrective action to the CBO and the CPM. A list of NCRs, for the reporting month, shall also be included in the following monthly compliance report.

CIVIL-4 After completion of finished grading and erosion and sedimentation control and drainage work, the project owner shall obtain the CBO's approval of the final grading plans (including final changes) for the erosion and sedimentation control work. The civil engineer shall state that the work within his/her area of responsibility was done in accordance with the final approved plans.

Verification: Within 30 days (or project owner- and CBO-approved alternative time frame) of the completion of the erosion and sediment control mitigation and drainage work, the project owner shall submit to the CBO, for review and approval, the final grading plans (including final changes) and the responsible civil engineer's signed statement that the installation of the facilities and all erosion control measures were completed in accordance with the final approved combined grading plans, and that the facilities are adequate for their intended purposes. The project owner shall submit a copy of the CBO's approval to the CPM in the next monthly compliance report.

STRUC-1 Prior to the start of any increment of construction, the project owner shall submit plans, calculations and other supporting documentation to the CBO for design review and acceptance for all project structures and equipment identified in the CBO-approved master drawing and master specifications list. The design plans and calculations shall include the lateral force procedures and details as well as vertical calculations.

Construction of any structure or component shall not begin until the CBO has approved the lateral force procedures to be employed in designing that structure or component. The project owner shall:

1. Obtain approval from the CBO of lateral force procedures proposed for project structures;

2. Obtain approval from the CBO for the final design plans, specifications, calculations, soils reports, and applicable quality control procedures. If there are conflicting requirements, the more stringent shall govern (for example, highest loads, or lowest allowable stresses shall govern). All plans, calculations, and specifications for foundations that support structures shall be filed concurrently with the structure plans, calculations, and specifications;

3. Submit to the CBO the required number of copies of the structural plans, specifications, calculations, and other required documents of the designated major structures prior to the start of on-site fabrication and installation of each structure, equipment support, or foundation;

4. Ensure that the final plans, calculations, and specifications clearly reflect the inclusion of approved criteria, assumptions, and methods used to develop the design. The final designs, plans, calculations, and specifications shall be signed and stamped by the responsible design engineer; and

5. Submit to the CBO the responsible design engineer's signed statement that the final design plans conform to applicable LORS.

Verification: At least 60 days (or project owner- and CBO-approved alternative time frame) prior to the start of any increment of construction of any structure or component listed in the CBO-approved master drawing and master specifications list, the project owner shall submit to the CBO the above final design plans, specifications and calculations, with a copy of the transmittal letter to the CPM.

The project owner shall submit to the CPM, in the next monthly compliance report, a copy of a statement from the CBO that the proposed structural plans, specifications, and calculations have been approved and comply with the requirements set forth in applicable engineering LORS.

STRUC-2 The project owner shall submit to the CBO the required number of sets of the following documents related to work that has undergone CBO design review and approval:

1. Concrete cylinder strength test reports (including date of testing, date sample taken, design concrete strength, tested cylinder strength, age of test, type and size of sample, location and quantity of concrete placement from which sample was taken, and mix design designation and parameters);

2. Concrete pour sign-off sheets;

3. Bolt torque inspection reports (including location of test, date, bolt size, and recorded torques);

4. Field weld inspection reports (including type of weld, location of weld, inspection of non-destructive testing (NDT) procedure and results, welder qualifications, certifications, qualified procedure description or number (ref: AWS); and

5. Reports covering other structural activities requiring special inspections shall be in accordance with the 2013 CBC.

Verification: If a discrepancy is discovered in any of the above data, the project owner shall, within five days, prepare and submit an NCR describing the nature of the discrepancies and the proposed corrective action to the CBO, with a copy of the transmittal letter to the CPM. The NCR shall reference the condition(s) of certification and the applicable CBC chapter and section. Within five days of resolution of the NCR, the project owner shall submit a copy of the corrective action to the CBO and the CPM.

The project owner shall transmit a copy of the CBO's approval or disapproval of the corrective action to the CPM within 15 days. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action to obtain CBO's approval.

STRUC-3 The project owner shall submit to the CBO design changes to the final plans required by the 2013 CBC, including the revised drawings, specifications, calculations, and a complete description of, and supporting rationale for, the proposed changes, and shall give to the CBO prior notice of the intended filing.

Verification: On a schedule suitable to the CBO, the project owner shall notify the CBO of the intended filing of design changes, and shall submit the required number of sets of revised drawings and the required number of copies of the other above-mentioned documents to the CBO, with a copy of the transmittal letter to the CPM. The project owner shall notify the CPM, via the monthly compliance report, when the CBO has approved the revised plans.

STRUC-4 Tanks and vessels containing quantities of toxic or hazardous materials exceeding amounts specified in the 2013 CBC shall, at a minimum, be designed to comply with the requirements of that chapter.

Verification: At least 30 days (or project owner- and CBO-approved alternate time frame) prior to the start of installation of the tanks or vessels containing the above specified quantities of toxic or hazardous materials, the project owner shall submit to the CBO for design review and approval final design plans, specifications, and calculations, including a copy of the signed and stamped engineer's certification.

The project owner shall send copies of the CBO approvals of plan checks to the CPM in the following monthly compliance report. The project owner shall also transmit a copy of the CBO's inspection approvals to the CPM in the monthly compliance report following completion of any inspection.

MECH-1 The project owner shall submit, for CBO design review and approval, the proposed final design, specifications and calculations for each plant major piping and plumbing system listed in the CBO-approved master drawing and master specifications list. The submittal shall also include the applicable QA/QC procedures. Upon completion of construction of any such major piping or plumbing system, the project owner shall request the CBO's inspection approval of that construction.

The responsible mechanical engineer shall stamp and sign all plans, drawings, and calculations for the major piping and plumbing systems, subject to CBO design review and approval, and submit a signed statement to the CBO when the proposed piping and plumbing systems have been designed, fabricated, and installed in accordance with all of the applicable laws, ordinances, regulations and industry standards, which may include, but are not limited to:

- American National Standards Institute (ANSI) B31.1 (Power Piping Code);
- ANSI B31.2 (Fuel Gas Piping Code);
- ANSI B31.3 (Chemical Plant and Petroleum Refinery Piping Code);
- ANSI B31.8 (Gas Transmission and Distribution Piping Code);
- NACE R.P. 0169-83;
- NACE R.P. 0187-87;
- NFPA 56;
- Title 24, California Code of Regulations, Part 5 (California Plumbing Code);
- Title 24, California Code of Regulations, Part 6 (California Energy Code, for building energy conservation systems and temperature control and ventilation systems);
- Title 24, California Code of Regulations, Part 2 (California Building Code); and
- City of Huntington Beach codes.

The CBO may deputize inspectors to carry out the functions of the code enforcement agency.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of any increment of major piping or plumbing construction listed in the CBO-approved master drawing and master specifications list, the project owner shall submit to the CBO for design review and approval the final plans, specifications, and calculations, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with applicable LORS, and shall send the CPM a copy of the transmittal letter in the next monthly compliance report.

The project owner shall transmit to the CPM, in the monthly compliance report following completion of any inspection, a copy of the transmittal letter conveying the CBO's inspection approvals.

MECH-2 For all pressure vessels installed in the plant, the project owner shall submit to the CBO and California Occupational Safety and Health Administration (Cal-OSHA), prior to operation, the code certification papers and other documents required by applicable LORS. Upon completion of the installation of any pressure vessel, the project owner shall request the appropriate CBO and/or Cal-OSHA inspection of that installation.

The project owner shall:

1. Ensure that all boilers and fired and unfired pressure vessels are designed, fabricated, and installed in accordance with the appropriate section of the ASME Boiler and Pressure Vessel Code, or other applicable code. Vendor certification, with identification of applicable code, shall be submitted for prefabricated vessels and tanks; and

2. Have the responsible design engineer submit a statement to the CBO that the proposed final design plans, specifications, and calculations conform to all of the requirements set forth in the appropriate ASME Boiler and Pressure Vessel Code or other applicable codes.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of on-site fabrication or installation of any pressure vessel, the project owner shall submit to the CBO for design review and approval, the above listed documents, including a copy of the signed and stamped engineer's certification, with a copy of the transmittal letter to the CPM.

The project owner shall transmit to the CPM, in the monthly compliance report following completion of any inspection, a copy of the transmittal letter conveying the CBO's and/or Cal-OSHA inspection approvals.

MECH-3 The project owner shall submit to the CBO for design review and approval the design plans, specifications, calculations, and quality control procedures for any heating, ventilating, air conditioning (HVAC) or refrigeration system. Packaged HVAC systems, where used, shall be identified with the appropriate manufacturer's data sheets.

The project owner shall design and install all HVAC and refrigeration systems within buildings and related structures in accordance with the CBC and other applicable codes. Upon completion of any increment of construction, the project owner shall request the CBO's inspection and approval of that construction. The final plans, specifications and calculations shall include approved criteria, assumptions, and methods used to develop the design. In addition, the responsible mechanical engineer shall sign and stamp all plans, drawings and calculations and submit a signed statement to the CBO that the proposed final design plans, specifications and calculations conform with the applicable LORS.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of construction of any HVAC or refrigeration system, the project owner shall submit to the CBO the required HVAC and refrigeration calculations, plans, and specifications, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the CBC and other applicable codes, with a copy of the transmittal letter to the CPM.

ELEC-1 Prior to the start of any increment of electrical construction for all electrical equipment and systems 110 Volts or higher (see a representative list, below) the project owner shall submit, for CBO design review and approval, the proposed final design, specifications, and calculations. Upon approval, the above listed plans, together with design changes and design change notices, shall remain on the site or at another accessible location for the operating life of the project. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. All transmission facilities (lines, switchyards, switching stations, and substations) are handled in conditions of certification in the Transmission System Engineering section of this document.

A. Final plant design plans shall include:

1. One-line diagram for the 13.8 kV, 4.16 kV and 480 V systems;
2. System grounding drawings;
3. Lightning protection system; and
4. Hazard area classification plan.

B. Final plant calculations must establish:

1. Short-circuit ratings of plant equipment;
2. Ampacity of feeder cables;
3. Voltage drop in feeder cables;
4. System grounding requirements;
5. Coordination study calculations for fuses, circuit breakers and protective relay settings for the 13.8 kV, 4.16 kV and 480 V systems;
6. System grounding requirements;
7. Lighting energy calculations; and
8. 110 volt system design calculations and submittals showing feeder sizing, transformer and panel load confirmation, fixture schedules and layout plans.

C. The following activities shall be reported to the CPM in the monthly compliance report:

   1. Receipt or delay of major electrical equipment;

   2. Testing or energization of major electrical equipment; and

   3. A signed statement by the registered electrical engineer certifying that the proposed final design plans and specifications conform to requirements set forth in the Energy Commission decision.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of each increment of electrical construction, the project owner shall submit to the CBO for design review and approval the above listed documents. The project owner shall include in this submittal a copy of the signed and stamped statement from the responsible electrical engineer attesting compliance with the applicable LORS, and shall send the CPM a copy of the transmittal letter in the next monthly compliance report.

REFERENCES

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)

Petition to Amend Final Commission Decision

GEOLOGY AND PALEONTOLOGY

Mike Conway

SUMMARY OF CONCLUSIONS

The Petition to Amend (PTA) for the Huntington Beach Energy Project (HBEP) does not seek to substantially modify the existing Geology and Paleontology conditions of certification, but staff proposes an additional condition of certification to mitigate potential impacts to public health and safety from tsunami inundation. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that supplementation to the 2014 HBEP Commission Decision is necessary for Geology and Paleontology. The Committee should re-analyze the conclusions of the 2014 Decision alongside this new information. This section augments the existing record to reflect current environmental conditions and policy considerations.

INTRODUCTION

In this section, Energy Commission staff discusses potential impacts of the amended HBEP on Geology and Paleontology. The HBEP was originally licensed as a 939-megawatt (MW) project in November 2014. The proposed amendment seeks to modify each of the two power block turbine configurations. The amended project would consist of two gas turbine generators and a steam turbine in a two-on-one combined-cycle configuration for power Block 1, with a 644 MW capacity, and two simple-cycle gas turbines for power Block 2, with 200 MW capacity. Total generating capacity of the amended HBEP would be reduced from 939 MW to 844 MW. The amended project would require a 1.4-acre increase in total project size, bringing the project up to 30-acres. An increase in temporary project laydown and parking would also be required. Total temporary construction area would be 22-acres.

SUMMARY OF THE DECISION

The 2014 Commission Decision for the project did not find any immitigable impacts to geologic or paleontological resources. The Decision states that no known mineralogical or paleontological resources exist at the project site, but required conditions **PAL-1** through **PAL-8** 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, through condition of certification **GEO-1,** and to identify abandoned gas wells, through condition of certification **GEO-2**.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

Applicable LORS	Description
Federal	The site is not located on federal land and there are no federal regulations directly applicable to the geological or paleontological conditions at the project site
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).
Alquist-Priolo Earthquake Fault Zoning Act, Public Resources Code (PRC), section 2621–2630	Mitigates against surface fault rupture of known active faults beneath occupied structures. Requires disclosure to potential buyers of existing real estate and a 50-foot setback for new occupied buildings.
Seismic Hazards Mapping Act, PRC section 2690–2699	Maps identify areas (zones) that are subject to the effects of strong ground shaking, such as liquefaction, landslides, tsunamis, and seiches. Requires a geotechnical report be prepared that defines and delineates any seismic hazard prior to approval of a project located in a seismic hazard zone.
CEQA, Appendix G Environmental Checklist Form	Asks if project would have impacts on paleontological and mineralogical resources or a unique geological feature.
Local	
City of Huntington Beach General Plan	The city of Huntington Beach addresses public safety and welfare in the city through implementation of its General Plan and compliance with applicable local regulations stated in the *Huntington Beach Municipal Code*. General Plan policies specific to geologic, soil, and seismic hazards are listed in the Environmental Hazards Element.
Huntington Beach Municipal Code and Grading Ordinance	The city adopted the 2010 CBC as the basis for its own Building Code. Site development work in the city is required to comply with the *Huntington Beach Building Code* and all state requirements pertaining to geologic, soil, and seismic hazards. The Grading and Excavation Code sets forth rules and regulations to control excavation, grading, earthwork and site improvement construction, and establishes administrative requirements for issuance of permits and approvals of plans and inspection of grading and construction.
Huntington Beach Municipal Code City Specification 429 Methane District Building Permit Requirements	The city of Huntington Beach strongly recommends not building structures over or near abandoned oil well or petroleum contaminated soil. City Specification 429 directs the assessment of, and provides mitigation measures for, areas proposed for construction where methane gas in soil is likely to occur.
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 Commission Decision (CEC, 2014). There are no significant geologic resources present in the project area, therefore there is no potential to impact those resources. There is however the potential to encounter paleontological resources during construction of the project.

CONSTRUCTION IMPACTS AND MITIGATION

Since construction of the proposed project would include significant amounts of grading, foundation excavation, and utility trenching, staff considers the probability that paleontological resources would be encountered during such activities to be high when native materials are encountered, based on Society of Vertebrate Paleontology (SVP2010) 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.

OPERATION IMPACTS AND MITIGATION

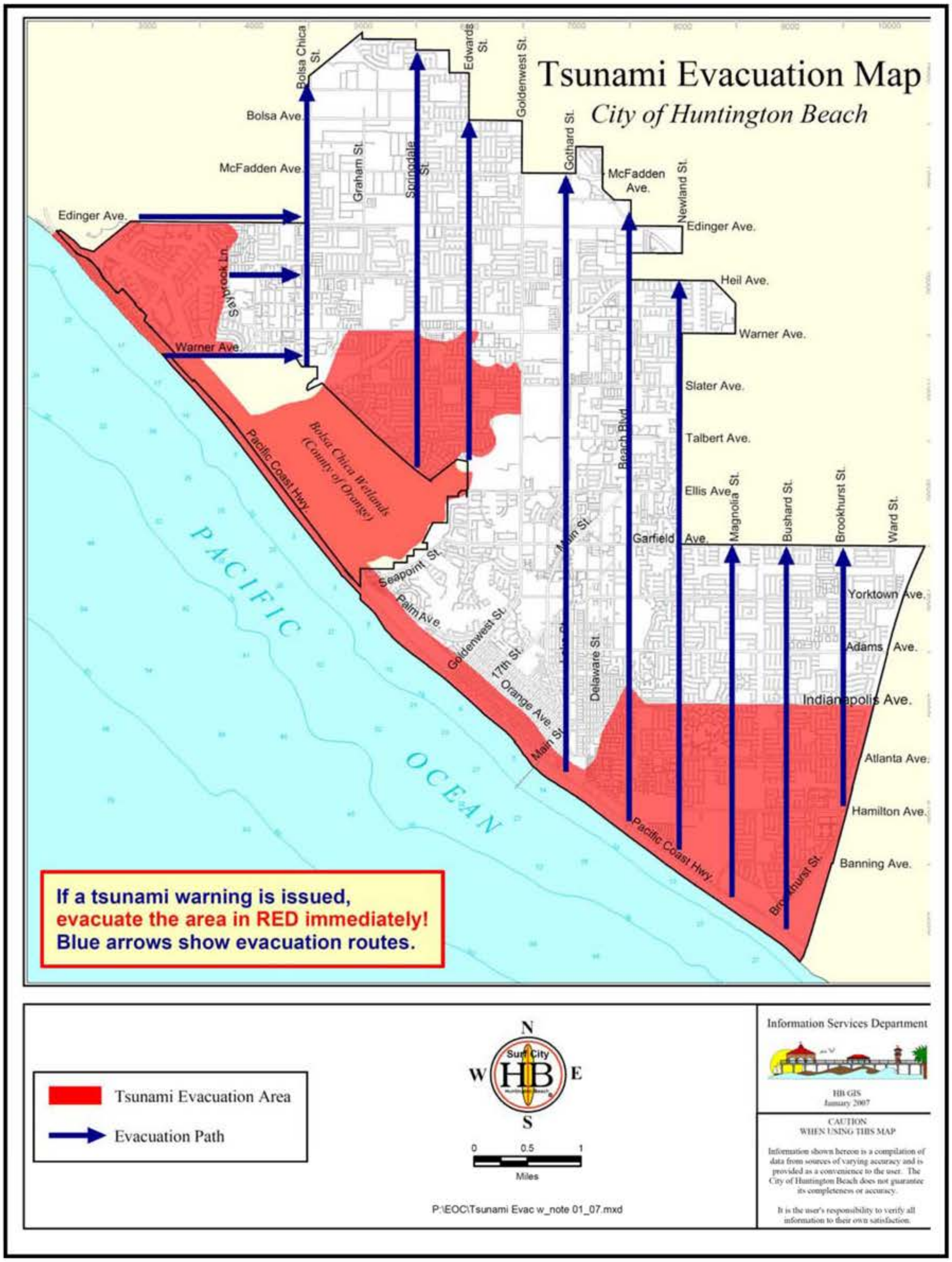
The geologic hazards present at the amended HBEP site are essentially the same as those considered in the Commission Decision. These potential hazards can be effectively mitigated through facility design as required by the California Building Code (2013) and condition of certification **GEO-1**. **GEO-1** specifically includes requirements that project design consider potential impacts of inundation from a tsunami. In this analysis staff has discovered additional information since licensing of the HBEP that can be used to further analyze potential impacts from tsunami which is presented below.

Tsunami

Given the current planning scenario that shows the project site is in the tsunami inundation zone (CGS2009), staff is concerned there may be a threat of impact to public health and safety from site flooding. Also, since the science behind estimating sea-level rise is evolving, it is possible projections could change during the life of the project and that the project design would not adequately incorporate mitigation for potential site inundation. In addition, recent fault studies and tsunami modeling that are currently being evaluated by the scientific community could add to the potential for tsunami impacts at the site. Staff concludes that it would be appropriate for the project owner to be prepared to respond to a potential tsunami event and ensure that all workers and site visitors would be safe from an event similar to the nearby areas of the city of Huntington Beach that are located in a tsunami zone.

The city of Huntington Beach prepared a Tsunami Evacuation Route map for its residents. The HBEP site is located within evacuation Zone 4. The proposed evacuation route from the site, as identified on the map, would be to travel northward on Newland Street. The nearest identified Safe Areas are Drew Park and Hawes Park, which are both approximately two miles north of the HBEP site (CITY2007). See **Geology and Paleontology Figure 1** for details about the evacuation map.

GEOLOGY AND PALEONTOLOGY - FIGURE 1
Huntington Beach Energy Project – Tsunami Evacuation Map



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: CITY2007

Staff recommends the project owner be required to prepare and implement a Tsunami Hazard Mitigation Plan (THMP) in accordance with condition of certification **GEO-3**. The THMP would include, among other things, a discussion of the city of Huntington Beach evacuation plan and how it applies to the project. It would also include discussion of criteria for a response to ensure public safety for a tsunami event and show where on and offsite refuge can be accessed, and recommended evacuation routes. The THMP would also include a training program for visitors and workers. The purpose of training would be to inform workers and visitors on how to respond to tsunami hazards and where they may obtain refuge in the event it is determined it is necessary to evacuate the project site.

The THMP would be updated whenever the city of Huntington Beach or Orange County hazard response plans are updated. Whenever there is an update in hazard response plans the project owner shall submit an updated THMP to the compliance project manager (CPM).

The potential for, and mitigation of, the effects of tsunami or seiche caused inundation on the proposed site should also be addressed in a project-specific geotechnical report, per CBC 2013 in accordance with conditions of certification **GEO-1** and conditions of certification in Facility Design **GEN-1**, **GEN-5** and **CIVIL-1**. Mitigation of tsunami run-up hazards includes structural and civil engineering evaluation, strengthening of seafront structures and providing emergency warning systems. Structural reinforcement at the site can be included for tsunami protection, as deemed appropriate at the detailed design stage by the project structural engineer.

CUMULATIVE IMPACTS AND MITIGATION

There are no changes to the cumulative impacts section of the Commission Decision caused by the proposed amendment changes. As a result, no additional mitigation is considered necessary.

CONCLUSIONS AND RECOMMENDATIONS

Staff proposes to add condition of certification **GEO-3** to protect HBEP employees and visitors from the threat of tsunami. In addition, staff is proposing minor changes to update the conditions of certification in this section for the purpose of making the existing requirements more clear – staff does not believe these proposed conditions impose any new requirements on the owner.

PROPOSED CONDITIONS OF CERTIFICATION

GEO-1 SOILS ENGINEERING REPORT REQUIRED

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. The project owner shall conduct a geotechnical investigation that identifies expected dewatering volumes and the spatial extent of drawdown effects of that dewatering. If the investigation shows that dewatering is likely to affect nearby wetlands or environmentally sensitive habitat areas, mitigation measures shall be incorporated into the final design plans required pursuant to condition of certification GEN-2.

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 CPM at least 30 days prior to grading.

GEO-2 COMPLIANCE WITH CITY OF HUNTINGTON BEACH MUNICIPAL CODE SECTION 17.04.085.

The project owner shall comply with the requirements of Huntington Beach Municipal Code Section 17.04.085 to ensure the existing and previously identified abandoned gas well on the site, and any additional wells that may be identified during grading and construction, are appropriately mitigated and made safe. The project owner shall consult with the Fire Chief to determine whether any of the following requirements of the municipal code apply, and shall submit the recommendations of the Fire Chief to the CPM for review and approval.

As required, the permit shall specifically include:

1) a site soil testing plan capable of detecting the presence of methane in the near surface soils,

2) field testing as specified in the approved plan,

3) laboratory test data,

4) pre-site disturbance mitigation if high concentrations of methane are discovered during testing,

5) site audits, and

6) area well documentation and review.

In accordance with City Specification No, 429, the permit shall also include designs for recommended methane control systems necessary to mitigate these potential hazards, if present.

Verification: The project owner shall include in the application for a Methane District Building Permit a copy of the construction project Site Plan Review approved by the California Department of Conservation Division of Oil, Gas and Geothermal Resources (DOGGR) that is on file with the Huntington Beach Fire Department PetroChem section. A copy of the site plan review, application for the Methane District Building Permit and any comments by Huntington Beach Fire Chief are to be provided to the CPM at least 30 days prior to initiation of grading.

GEO-3 TSUNAMI HAZARD MITIGATION PLAN

The project owner shall ensure that all staff and visitors at the project site are informed of tsunami hazards in the region and have been shown how and where to evacuate the site if there is potential for a tsunami to affect public health and safety at the site. The project owner shall ensure that the information provided to staff and visitors complies with the recommendations and procedures provided by the city of Huntington Beach or Orange County.
The project owner shall provide a Tsunami Hazard Mitigation Plan (THMP) to the Compliance Project Manager (CPM) for review and approval.

The THMP shall include:

A. A general discussion of tsunami hazard and the public safety risk they present at the site.

B. Identification of what tsunami hazards exist specific to the project site and how the project owner proposes to ensure compliance with applicable hazard response plans.

C. A discussion of criteria for a response to ensure public safety for a tsunami event and show where on and offsite refuge can be accessed, and evacuation routes.

D. Identification of any site modifications or signage that may be needed to show how and where refuge is accessible.

E. **The THMP shall also include a training program for visitors and workers. The purpose of training is to inform workers and visitors how to respond to tsunami hazards and where they may obtain refuge in the event it is determined it is necessary to evacuate the project site. The project owner may include the training for tsunami hazard response as a part of the Worker Environmental Awareness Program required in PAL-4 below. The training shall include:**

1. **Information on who and how staff and visitors will be notified that there is a potential for a tsunami event to impact the site and how they should respond;**

2. **Graphics showing methods of seeking refuge and routes for evacuation of the site;**

3. **A certification of completion form signed by each worker indicating that he/she has received the training; and**

4. **A sticker that shall be placed on hard hats indicating that training has been completed.**

5. **Submittal of 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 training.**

The THMP shall be updated if the city of Huntington Beach or Orange County updates their tsunami response plan. When there is an update to hazard response plans, the project owner shall submit for CPM approval an updated THMP showing how the project owner proposes to comply.

Verification: The project owner shall submit the THMP 60 days prior to ground disturbance for CPM review and approval. The project owner shall submit any subsequent updates to the THMP to the CPM within 90 days of an update to an applicable THMP.

PAL-1 APPOINTMENT AND QUALIFICATIONS OF PALEONTOLOGICAL RESOURCE SPECIALIST (PRS)

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 (PRR), the project owner shall obtain CPM approval of the replacement PRS. 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.

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 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 monitor as he or she deems necessary on the project. Paleontologic resource monitors (PRMs) shall have the equivalent or combination of the following qualifications approved by the CPM:

- o BS or BA degree in geology or paleontology and one year of experience monitoring in California; or
- o AS or AA in geology, paleontology, or biology and four years' experience monitoring in California; or
- o 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.

~~The project owner may replace the PRS by submitting the required resume, references and contact information of the proposed alternate to the CPM.~~

Verification:

(1) At least 60 days prior to **the start of** ground disturbance, the project owner shall submit **a**~~the~~ resume **and statement** of **availability of its designated PRS** ~~the proposed PRS, with at least three references and contact information, to the CPM~~ for **on-site work to the CPM, whose**~~review and~~ approval **must be obtained**.

(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. The letter shall state that the identified monitors meet the minimum qualifications for paleontological resource monitoring as required by this condition of certification. If additional monitors are obtained during the project, the PRS shall provide additional letters and resumes to the CPM. The letter shall be provided to the CPM for approval no later than one week prior to the monitor's beginning on-site duties.

(3) Prior to any change in the PRS, the project owner shall submit the resume of the proposed new PRS to the CPM for review and approval.

~~The project owner may replace a PRS by submitting the required resume, references and contact information to the CPM at least ten working days prior to the termination or release of the then-current CRS. In an emergency, the project owner shall immediately notify the CPM to discuss the qualifications and approval of a short-term replacement while a permanent CRS is proposed to the CPM for consideration.~~

PAL-2 DOCUMENTS PROVIDED TO THE PRS

The project owner shall provide to the PRS and the CPM, for approval, maps and drawings showing the footprint of the power plant, construction lay down areas, and all related facilities. Maps shall identify all areas of the project where ground disturbance is anticipated. If the PRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the PRS and CPM. The site grading plan and the plan and profile drawings for the utility lines would be acceptable for this purpose. The plan drawings should show the location, depth, and extent of all ground disturbances and be at a scale between 1 inch = 40 feet and 1 inch = 100 feet. If the footprint of the project or its linear facilities change, the project owner shall provide maps and drawings reflecting those changes to the PRS and CPM.

If construction of the project proceeds in phases, maps and drawings may be submitted prior to the start of each phase. A letter identifying the proposed schedule of each project phase shall be provided to the PRS and CPM. Before work commences on affected phases, the project owner shall notify the PRS and CPM of any construction phase scheduling changes.

At a minimum, the project owner shall ensure that the PRS or PRM consults weekly with the project superintendent or construction field manager to confirm area(s) to be worked the following week, until ground disturbance is completed.

Verification:

(1) At least 30 days prior to the start of ground disturbance, the project owner shall provide the maps and drawings to the PRS and CPM.

(2) If there are changes to the footprint of the project, revised maps and drawings shall be provided to the PRS and CPM at least 15 days prior to the start of ground disturbance.

(3) If there are changes to the scheduling of the construction phases, the project owner shall submit a letter to the CPM within 5 days of identifying the changes.

PAL-3 PALEONTOLOGICAL RESOURCES MONITORING AND MITIGATION PLAN (PRMMP)

The project owner shall ensure that the PRS prepares a Paleontological Resources Monitoring and Mitigation Plan (PRMMP) 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. The PRMMP shall be used as the basis of discussion when 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 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 PRMMP procedures;

2. Identification of the person(s) expected to assist with each of the tasks identified within the PRMMP and these 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 plan for monitoring and sampling at these locations;

6. A discussion of procedures to be followed: (a) in the event of a significant fossil discovery, (b) 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 meet the Society of Vertebrate Paleontology's standards and requirements for the curation of paleontological resources;

9. Identification of the institution that has agreed to receive data and fossil materials collected, requirements or specifications for materials delivered for curation, and how they will be met, and the name and phone number of the contact person at the institution; and

10. A copy of the paleontological conditions of certification.

Verification: At least 30 days prior to ground disturbance, the project owner shall provide a copy of the PRMMP to the CPM. 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 PREPARATION OF WORKER ENVIRONMENTAL AWARENESS PROGRAM (WEAP)

Prior to ground disturbance the project owner and the PRS shall prepare a CPM-approved Worker Environmental Awareness Program (WEAP). 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 for project sites containing units of high paleontologic sensitivity;

3. Information that the PRS or PRM has the authority to stop or redirect construction in the event of a discovery or unanticipated impact to a paleontological resource;

4. Instruction that employees are to stop or redirect work in the vicinity of a find and to contact their supervisor and the PRS or PRM;

5. An informational brochure that identifies reporting procedures in the event of a discovery;

6. A WEAP certification of completion form signed by each worker indicating that he/she has received the training; and

7. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

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 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 15 days prior to ground disturbance, the project owner shall submit to the CPM for approval the final WEAP and training script.

PAL-5 WORKER ENVIRONMENTAL AWARENESS PROGRAM (WEAP) TRAINING

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 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 other areas of interest or concern. A WEAP certification of completion form shall be used to document who has received the required training.

Verification:

(1) 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. The MCR shall also include a running total of all persons who have completed the training to date.

(2) 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-6 DUTIES OF THE PRS AND PRM

The project owner shall ensure that the PRS and PRM(s) monitor, consistent with the PRMMP, all construction-related grading, excavation, trenching, and augering in areas where potential fossil-bearing materials have been identified, both at the site and along any constructed linear facilities associated with the project. In the event that the PRS determines full-time monitoring is not necessary in locations that were identified as potentially fossil-bearing in the PRMMP, the project owner shall notify and seek the concurrence of the CPM.

The project owner shall ensure that the PRS and PRM(s) have the authority to stop or redirect construction if paleontological resources are encountered. The project owner shall ensure that there is no interference with monitoring activities unless directed by the PRS. Monitoring activities shall be conducted as follows:

1. Any change of monitoring from the accepted schedule in the PRMMP shall be proposed in a letter or email from the PRS and the project owner to the CPM prior to the change in monitoring and be included in the monthly compliance report. The letter or email shall include the justification for the change in monitoring and be submitted to the CPM for review and approval.

2. The project owner shall ensure that the PRM(s) keep a daily monitoring log of paleontological resource activities. The PRS may informally discuss paleontological resource monitoring and mitigation activities with the CPM at any time.

3. The project owner shall ensure that the PRS notifies the CPM within 24 hours of the occurrence of any incidents of non-compliance with any paleontological resources conditions of certification. The PRS shall recommend corrective action to resolve the issues or achieve compliance with the conditions of certification.

4. For any significant paleontological resources encountered, either the project owner or the PRS shall notify the CPM within 24 hours, or Monday morning in the case of a weekend event, when construction has been stopped because of a paleontological find.

The project owner shall ensure that the PRS prepares a summary of monitoring and other paleontological activities that will be included in each 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, and other activities. A section of the report shall include the geologic units or subunits encountered, descriptions of samplings within each unit, and a list of identified fossils. A final section of the report will address any issues or concerns about the project relating to paleontologic monitoring, including any incidents of non-compliance or any changes to the monitoring plan that have been approved by the CPM. If no monitoring took place during the month, the report shall include an explanation in the summary as to why monitoring was not conducted.

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 that 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 PALEONTOLOGICAL RESOURCES REPORT (PRR)

The project owner shall ensure preparation of a Paleontological Resources Report (PRR) by the designated PRS. The PRR shall be prepared following completion of 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 approval.

The report shall include, but not be limited to, a description and inventory of recovered fossil materials; a map showing the location of paleontological resources encountered; and the PRS' description of sensitivity and significance of those resources.

Verification: Within 90 days after completion of ground-disturbing activities, including landscaping, the project owner shall submit the PRR under confidential cover to the CPM.

PAL-8 DISPOSITION OF FOSSIL MATERIAL

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

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

CGS2009 - Tsunami Inundation Map for Emergency Planning, Newport Beach Quadrangle. California Geological Survey. March 15, 2009.

CITY2007 - City of Huntington Beach Tsunami Evacuation Map. City of Huntington Beach Information Services Department. January 2007.

SVP2010 - Society of Vertebrate Paleontology, Impact Mitigation Guidelines Revision Committee Standard Procedures for the Assessment and Mitigation of Adverse Impacts to Paleontological Resources, 2010.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
POWER PLANT EFFICIENCY

Edward Brady

SUMMARY OF CONCLUSIONS

Similar to the conclusions in the 2014 Energy Commission Final Decision (Decision) for the HBEP, the amended HBEP 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 Decision is necessary for Power Plant Efficiency. The Committee may rely upon the analysis and conclusions of the Decision with regards to Power Plant Efficiency and does not need to re-analyze them.

The thermal efficiency of the combined-cycle portion of the amended HBEP would compare quite favorably with the efficiency of the licensed combined-cycle HBEP. Furthermore, the efficiency of the simple-cycle units for the amended HBEP would be comparable to the efficiency of other modern simple-cycle units. The needed quantities of natural gas fuel for the amended project would not result in a significant impact on natural gas supplies and resources

INTRODUCTION

Staff has reviewed the Decision (CEC 2014bb) and analyzed the modifications proposed for the HBEP (HBEP 2015a), which include revising the approved pair of three-on-one combined-cycle electric power generating blocks to a single two-on-one combined-cycle power block and two simple-cycle combustion-turbine generators (CTGs). 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 Decision.

SUMMARY OF THE DECISION

The Decision (CEC 2014bb) found that the HBEP's efficiency of 46 percent was comparable to the average fuel efficiency of a typical rapid-response/flexible combined-cycle power plant. The Decision concluded that the needed quantities of natural gas fuel for the project will create a less-than-significant impact on natural gas supplies and resources and found the source of natural gas fuel for the project to be reliable.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

No federal, state, or local laws, ordinances, regulations, or standards (LORS) apply to power plant efficiency.

ENVIRONMENTAL IMPACT ANALYSIS

The approved HBEP includes two independent, three-on-one combined-cycle power blocks, consisting of a total of six Mitsubishi M501DA CTGs, six heat recovery steam generators (HRSGs), and two steam turbine generators (STGs), totaling 939 megawatts (MW). The amended HBEP would substitute these power blocks with a single two-on-one combined-cycle power block using two General Electric (GE) 7FA CTGs, two HRSGs, and one STG, and a second power block containing two GE LMS100 PB CTG simple cycle units, all totaling 844 MW (HBEP 2015a, §§ 1.0, 2.1).

The efficiency of the combined cycle portion of the amended project would be 56 percent (HBEP 2015a, Figures 2.1-5a and 2.1-5b). This efficiency compares quite favorably with the licensed HBEP's efficiency of 46 percent.

The efficiency of the simple-cycle portion of the amended project would be 41 percent (HBEP 2015a, § 2.6.2).[1] The LMS100 PB is a modern CTG and its efficiency is comparable to the efficiency of other, currently-operating, modern simple cycle CTGs.

Consistent with the licensed HBEP, natural gas fuel for the amended HBEP would be delivered to the project site via an existing 16-inch-diameter Southern California Gas Company (SoCalGas) pipeline located on the northwest side of the project site (HBEP 2015a, § 2.1.1.3). 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 annual supplies of natural gas. However, gas demand is both instantaneous and long-term (e.g., annual), and the closure and potential long-term de-rate of the SoCalGas' Aliso Canyon natural gas storage facility, located north/northwest of the San Fernando Valley near Los Angeles, may impact instantaneous natural gas deliveries to the power plants it serves. This includes the existing Huntington Beach Generating Station (HBGS) and it could potentially impact the amended HBEP.

The state's program to phase out once-through cooling power plants is forcing the retirement of a substantial amount of dispatchable generation in coastal areas and their replacement with new electrical generation to preserve the reliability of the California electric grid system. In keeping with this program, the approximately 50-60 year-old retiring once-through cooling HBGS would be replaced by the modern and more efficient amended HBEP, resulting in less natural gas consumption per megawatt (MW) of generation. Additionally, dispatch orders generally call for the most efficiently-generated energy first, especially when peaking capacity is required (the amended HBEP would include peaking units). Therefore, the older, less efficient plants are being displaced by modern and more efficient gas-fired power generation. The electric grid system's reliance on new generation in the region rather than on the existing aging plants would result in further decreases in natural gas consumption per MW of generation and would help alleviate the potential effect of the closure of Aliso Canyon. The amended HBEP would start up 4-7 years into the future (HBEP 2015a, § 2.0) and it is not clear if the closure or de-rate of Aliso Canyon will continue until then.

[1] This efficiency is based on the average climatic conditions at 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 Power Plant Efficiency analysis contained in the 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 Decision.

CONCLUSIONS AND RECOMMENDATIONS

Similar to the conclusions in the Decision for the HBEP, the amended project would create no significant impacts related to power plant efficiency. The thermal efficiency of the combined-cycle portion of the amended HBEP would compare quite favorably with the efficiency of the licensed combined-cycle HBEP. Furthermore, the efficiency of the simple-cycle units proposed for the amended HBEP would be comparable to the efficiency of other modern simple-cycle units. The needed quantities of natural gas fuel for the amended project would not result in a significant impact on natural gas supplies and resources.

PROPOSED CONDITIONS OF CERTIFICATION

The 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

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
POWER PLANT RELIABILITY
Edward Brady

SUMMARY OF CONCLUSIONS

Similar to the conclusions in the 2014 Energy Commission Final Decision (Decision) for the HBEP, the amended HBEP 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 other electric generation power plants, including the licensed HBEP. Also similar to the licensed project, 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 Decision is necessary for Power Plant Reliability. The Committee may rely upon the analysis and conclusions of the Decision with regards to Power Plant Reliability and does not need to re-analyze them.

INTRODUCTION

Staff has reviewed the Decision (CEC 2014bb) and analyzed the changes to the licensed Huntington Beach Energy Project (HBEP), which include revising the approved pair of three-on-one combined cycle electric power generating blocks to a single two-on-one combined cycle power block and a second power block containing two simple-cycle combustion turbine generators (CTGs) (HBEP 2015a). 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 Decision.

SUMMARY OF THE DECISION

The Decision (CEC 2014bb) found that the HBEP's plant maintenance program and redundant equipment list, the sources of the project's natural gas fuel and cooling 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 other power plants.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

No federal, state, or local/county laws, ordinances, regulations, or standards (LORS) apply to power plant reliability.

ANALYSIS

Similar to the licensed project, the amended project would include two independent power blocks. This arrangement provides inherent reliability. Failure of one power block cannot affect the operation of the other block, thereby allowing the power plant to continue to generate electricity, but at reduced output. Also, the amended HBEP's simple-cycle block would consist of two independent CTGs. Failure of one CTG would not hinder the operation of the other one, thus allowing the power block to continue to generate electricity (at reduced output). The amended HBEP's ancillary systems would also include adequate redundancy to ensure their continued operation if equipment fails (HBEP 2015a, § 2.5.2.1, Table 2.5-1).

The amendment describes the amended HBEP's plant maintenance program and the sources of natural gas fuel and cooling water supplies (HBEP 2015a, §§ 2.1.6, 2.1.8, 2.5.1), which are the same as the licensed HBEP. Also, similar to the licensed HBEP, the amended HBEP 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.

Consistent with the licensed HBEP, natural gas fuel for the amended HBEP would be delivered to the project site via an existing 16-inch-diameter Southern California Gas Company (SoCalGas) pipeline located on the northwest side of the project site (HBEP 2015a, § 2.1.1.3). 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 annual supplies of natural gas. However, gas demand is both instantaneous and long-term (e.g., annual), and the closure and potential long-term de-rate of the SoCalGas' Aliso Canyon natural gas storage facility, located north/northwest of the San Fernando Valley near Los Angeles, may impact instantaneous natural gas deliveries to the power plants it serves. This includes the existing Huntington Beach Generating Station (HBGS) and it could potentially impact the amended HBEP.

The state's program to phase out once-through cooling power plants is forcing the retirement of a substantial amount of dispatchable generation in coastal areas and their replacement with new electrical generation to preserve the reliability of the California electric grid system. In keeping with this program, the approximately 50-60 year-old retiring once-through cooling HBGS would be replaced by the modern and more efficient amended HBEP, resulting in less natural gas consumption per megawatt (MW) of generation. Additionally, dispatch orders generally call for the most efficiently-generated energy first, especially when peaking capacity is required (the amended HBEP would include peaking units). Therefore, the older, less efficient plants are being displaced by modern and more efficient gas-fired power generation. The electric grid system's reliance on new generation in the region rather than on the existing aging plants would result in further decreases in natural gas consumption per MW of generation and would help alleviate the potential effect of the closure of Aliso Canyon. The amended HBEP would start up 4-7 years into the future (HBEP 2015a, § 2.0) and it is not clear if the closure or de-rate of Aliso Canyon will continue until then.

Therefore, the amended HBEP would be able to demonstrate a level of plant availability and reliability that equals or exceeds reliability of existing power plants. 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 Decision.
- The circumstances under which the amended project would be undertaken would not require major revisions of the Power Plant Reliability analysis contained in the Decision.

CONCLUSIONS

Staff concludes that the amended HBEP 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 other power plants, including the licensed HBEP.

CONDITIONS OF CERTIFICATION

The 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

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
TRANSMISSION SYSTEM ENGINEERING

Laiping Ng and Mark Hesters

SUMMARY OF CONCLUSIONS

The proposed transmission facilities between the new generators at the Huntington Beach Energy Project (HBEP) and Southern California Edison (SCE) Huntington Beach Switching Station including the step-up transformers, the 230 kV overhead transmission lines, and terminations, are acceptable and would comply with all applicable laws, ordinances, regulations, and standards (LORS). The HBEP interconnection with the transmission grid would not require additional downstream transmission facilities (other than those proposed by the applicant) that require California Environmental Quality Act (CEQA) review.

The HBEP generation output is less than the generation output of the project as approved in the 2014 Energy Commission Decision (Decision). The HBEP would not cause additional downstream transmission impacts other than those identified in the Queue QC5 Phase II Interconnection Study Report Dated December 3, 2013, from California Independent System Operator (California ISO). The Study Report is still valid and no new study would be required.

Staff proposes no changes to Conditions of Certification TSE 1-5. The HBEP, as amended, would comply with LORS.

INTRODUCTION

The HBEP Petition to Amend (PTA) proposes to replace the licensed power block 1 with a two-on-one combined-cycle configuration and power block 2 with two simple-cycle gas turbine generators. Power block 1, with three generators, would generate at a total of 644 megawatts (MW) nominal output. Power block 2, with two generators, would generate approximately 200 MW nominal output. The nominal output from these two power blocks to the transmission system would be 844 MW. The amended HBEP generating facility has the potential to generate at a maximum output of 890 MW. This analysis is based on the maximum output to the SCE transmission system.

The approved two 230 kV overhead generator tie-lines which interconnect power block 1 and 2 to the Huntington Beach Switching Station remain unchanged. Power would be distributed to the transmission system in the same way as the approved HBEP.

SUMMARY OF THE DECISION

As stated in the Decision, two 230-kilovolt (kV) generator tie-lines will connect both HBEP power blocks 1 and 2 to the existing SCE 230-kV Huntington Beach Switching Station. The Huntington Beach Switching Station is connected to the SCE Ellis Substation. Power would be distributed the transmission system from the Ellis Substation.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The LORS from the original Commission decision still apply. No update is required.

TRANSMISSION SYSTEM ANALYSIS

As proposed in the PTA, the Huntington Beach Energy Project would consist of two power blocks. Power block 1 consists of two combustion turbine generators (CTG) and one steam turbine generator (STG). Each CTG is expected to generate at maximum 234.5 megawatts (MW) with a power factor of 0.85 and the STG is expected to generate at maximum 241 MW with a power factor of 0.85. Power block 2 consists of two combustion turbine generators. Each CTG is expected to generate approximate 103 MW with a power factor of 0.85.

For power block 1, the combustion turbine generators would each be connected to the low side of its dedicated 162/215/270 Megavolt Ampere (MVA) generator step-up (18/230 kV) transformer through its own 10,000-ampere generator circuit breaker, via a short 10,000 ampere isolated phase bus. The steam turbine generator would be connected through its own 9,000-ampere generator circuit breaker via a short 10,000-ampere isolated phase bus to the low side of its dedicated 171/228/285 MVA generator step-up (18/230 kV) transformer.

The high sides of the generator transformers would each be connected through their dedicated 2,000-ampere breakers and 600-ampere disconnect switches to the common generator tie bus. A single 230 kV generator tie-line would connect power block 1 through a 2,000-ampere disconnect switch, a 2,000-ampere breaker, and a motor-operated disconnect switch with ground, to the SCE Huntington Beach Switching Station.

For power block 2, combustion turbine generators unit 1 and unit 2 would each be connected to the low side of their dedicated 72/96/120 MVA generator step-up (13.8/230 kV) transformer through their own 8,000-ampere generator circuit breaker via a short 6,000-ampere isolated phase bus.

The high sides of the block 2 generator transformers would each be connected through dedicated 2,000-ampere circuit breakers and a 2,000-ampere motor-operated disconnect switch with ground to the common generator tie bus. A single 230 kV generator tie-line would connect power block 2 through a 2,000-ampere breaker and a 2,000-ampere motor-operated disconnect switch with ground to the SCE Huntington Beach Switching Station.

The overhead generator tie-line 1 would be built with 1033.5 thousand circular mil (kcmil) Aluminum Conductor Steel Supported (ACSS) that is approximately 0.22 mile-long. The overhead generator tie-line 2 would also be built with 1033.5 kcmil ACSS conductor that is approximately 0.16 mile-long. Power would be distributed to the SCE transmission grid through the Huntington Beach Switching Station. The ACSS is not typically used for generator interconnections and is rated at a higher operating temperature (200 degrees Celsius) than other transmission equipment which is typically rated at 80 degrees Celsius. A conductor like an Aluminum Conductor Steel Reinforced is more common and is typically rated at an 80 degree Celsius operating temperature.

Since the amended HBEP output is less than the approved HBEP, there will not be any additional downstream transmission impacts other than those identified in the HBEP California ISO Phase II Interconnection Study Report dated December 3, 2013. The Study Report is still valid and no new study is required. No new environmental impact analysis is necessary (HBEP 2015a section 2.0, HBEP 2015i Figure DR 57A-1, HBEP 2015n).

CONCLUSIONS AND RECOMMENDATIONS

The proposed transmission facilities between the new generators at the HBEP and SCE Huntington Beach Switching Station including the step-up transformers, the 230 kV overhead transmission lines, and terminations, are acceptable and would comply with all applicable LORS. The interconnection with the transmission grid would not require additional downstream transmission facilities (other than those proposed by the applicant) that require CEQA review.

The amended HBEP would not cause additional downstream transmission impacts other than those identified in the Queue QC5 Phase II Interconnection Study Report dated December 3, 2013, from California ISO. The Study Report is still valid and no new study would be required.

Staff proposes no changes to Conditions of Certification TSE 1-5. The amended HBEP would comply with LORS.

PROPOSED CONDITIONS OF CERTIFICATION

TSE-1 The project owner shall furnish to the CPM and to the CBO a schedule of transmission facility design submittals, a Master Drawing List, a Master Specifications List, and a Major Equipment and Structure List. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide designated packages to the CPM when requested.

Verification: Prior to the start of construction of transmission facilities, the project owner shall submit the schedule, a Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see list of major equipment in **Table 1: Major Equipment List** below). Additions and deletions shall be made to the table only with CPM and CBO approval. The project owner shall provide schedule updates in the monthly compliance report.

Table 1: Major Equipment List

Breakers
Step-up transformer
Switchyard
Busses
Surge arrestors
Disconnects
Take-off facilities
Electrical control building
Switchyard control building
Transmission pole/tower
Grounding system

TSE-2 For the power plant switchyard, outlet line and termination, the project owner shall not begin any construction until plans for that increment of construction have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. The following activities shall be reported in the monthly compliance report:

a) receipt or delay of major electrical equipment;

b) testing or energization of major electrical equipment; and

c) the number of electrical drawings approved, submitted for approval, and still to be submitted.

Verification: Prior to the start of each increment of construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications and calculations for equipment and systems of the power plant switchyard, outlet line, and termination, including a copy of the signed and stamped statement from the responsible electrical engineer verifying compliance with all applicable LORS, and send the CPM a copy of the transmittal letter in the next monthly compliance report.

TSE-3 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 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;* California ISO 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 of the project.

e) Termination facilities shall comply with applicable SCE interconnection standards.

f) The project owner shall provide to the CPM:

   i) Special Protection System (SPS) sequencing and timing if applicable,

   ii) A letter stating that the mitigation measures or projects selected by the transmission owners for each reliability criteria violation for which the project is responsible, are acceptable,

   iii) A copy of the executed Large Generator Interconnection Agreement (LGIA) signed by the California ISO and the project owner and approved by the Federal Energy Regulatory Commission.

<u>Verification</u>: Prior to the start of construction on modification of transmission facilities, the project owner shall submit to the CBO for approval:

a) Design drawings, specifications, and calculations conforming with CPUC General Order 95 or 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;* CA ISO 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"[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 and Regulations (Title 8); Articles 35, 36 and 37 of the *High Voltage Electric Safety Orders;* California ISO standards; National Electric Code (NEC); and related industry standards;

c) Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in charge, a route map, and an engineering description of the equipment and configurations covered by requirements **TSE-3** a) through f);

d) Special Protection System (SPS) sequencing and timing, if applicable, shall be provided concurrently to the CPM.

e) A letter stating that the mitigation measures or projects selected by the transmission owners for each reliability criteria violation for which the project is responsible, are acceptable,

f) A copy of the executed LGIA signed by the CAISO and the project owner and approved by the Federal Energy Regulatory Commission.

Prior to the start of construction of or 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-4 The project owner shall provide the following Notice to the California Independent System Operator (CAISO) prior to synchronizing the facility with the California Transmission system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the CAISO a letter stating the proposed date of synchronization; and

[1] Worst-case conditions for the foundations would include for instance, a dead-end or angle pole.

2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the CAISO Outage Coordination Department.

Verification: The project owner shall provide copies of the CAISO letter to the CPM when it is sent to the CAISO one week prior to initial synchronization with the grid. The project owner shall contact the CAISO Outage Coordination Department Monday through Friday, between the hours of 0700 and 1530 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the CAISO shall be provided electronically to the CPM one day before synchronizing the facility with the California transmission system for the first time.

TSE-5 The project owner shall be responsible for the inspection of the transmission facilities during and after project construction, and any subsequent CPM and CBO approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8, CCR, Articles 35, 36 and 37 of the “High Voltage Electric Safety Orders”, applicable interconnection standards, NEC and related industry standards. In case of non-conformance, the project owner shall inform the CPM and CBO in writing within 10 days of discovering such non-conformance and describe the corrective actions to be taken.

Verification: Within 60 days after first synchronization of the project, the project owner shall transmit to the CPM and CBO:

a) “As built” engineering description(s) and one-line drawings of the electrical portion of the facilities signed and sealed by the registered electrical engineer in responsible charge. A statement attesting to conformance with CPUC GO-95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the “High Voltage Electric Safety Orders”, and applicable interconnection standards, NEC, related industry standards.

b) An “as built” engineering description of the mechanical, structural, and civil portion of the transmission facilities signed and sealed by the registered engineer in responsible charge or acceptable alternative verification. “As built” drawings of the electrical, mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, if requested, for CPM audit as set forth in the “Compliance Monitoring Plan”.

c) A summary of inspections of the completed transmission facilities, and identification of any nonconforming work and corrective actions taken, signed and sealed by the registered engineer in charge.

REFERENCES

California ISO (California Independent System Operator) 1998a – California ISO Tariff Scheduling Protocol posted April 1998, Amendments 1,4,5,6, and 7 incorporated.

California ISO (California Independent System Operator) 1998b – California ISO Dispatch Protocol posted April 1998.

California ISO (California Independent System Operator) 2002a – California ISO Planning Standards, February 7, 2002.

California ISO (California Independent System Operator) 2007a – California ISO, FERC Electric Tariff, First Replacement Vol. No. 1, March, 2007.

California ISO (California Independent System Operator) 2009a – Large Generator Interconnection Procedures, ongoing.

CEC 2014d - Final Staff Assessment (TN 202405). Submitted to CEC/ Docket Unit June 2, 2014.

CEC 2014v - Huntington Beach Energy Project Revised Presiding Member's Proposed Decision (TN 203180). Submitted to CEC/Docket Unit on October 9, 2014.

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

HBEP 2012a - AES Southland Development, LLC / Stephen O'Kane (tn 66003). Application for Certification (AFC), Volume I & II, dated, 06/27/2012. Submitted to CEC/ Dockets on 06/27/2012.

HBEP 2012c - Stoel Rives LLP / Melissa A. Foster (tn 66490). Applicant's Data Adequacy Supplement, dated 08/06/2012. Submitted to CEC/ Dockets on 08/06/2012.

HBEP 2013kk - Stoel Rives LLP / Melissa A. Foster (tn 200631). California Independent System Operator's (CAISO)'s Phase I Interconnection Study Report (Transmission System Engineering) for HBEP, dated 09/24/13. Submitted to CEC/Dockets on 09/24/2013.

HBEP 2013ss - Stoel Rives LLP / Melissa A. Foster (tn 201469). CA ISO Cluster 5 Phase II Interconnection Study, dated 12/3/13. Submitted to CEC/Dockets on 12/23/2013.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HBEP 2015h - Data Responses, Set 1 (Responses to Data Request 1-74) (TN 206858). Submitted to CEC/Docket Unit on December 7, 2015.

HBEP 2015q - Project Owner's Follow-Up to Data Request Workshop 12-14-15 (TN 207011). Submitted to CEC/Docket Unit on December 14, 2015.

NERC (North American Electric Reliability Council). 2006. Reliability Standards for the Bulk Electric Systems of North America, May 2006.

WECC (Western Electricity Coordinating Council) 2006 – NERC/WECC Planning Standards, August 2006.

Alternatives

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)

Petition to Amend Final Commission Decision

ALTERNATIVES

John Hope, Matthew Layton, and David Vidaver

SUMMARY OF CONCLUSIONS

Staff reviewed alternatives previously analyzed for the licensed Huntington Beach Energy Project (HBEP) design and related facilities, alternative technologies, and the "no project" alternative. Alternatives previously found to be infeasible remain infeasible, and would not substantially reduce one or more significant effects of the amended HBEP. In addition, no new information shows alternatives which are considerably different from those analyzed in the previous staff assessment for the licensed HBEP that would substantially reduce one or more significant effects on the environment. Therefore, in accordance with California Environmental Quality Act (CEQA) Guidelines section 15162, staff concludes that no supplementation to the 2014 Commission Decision is necessary for Alternatives. The Committee may rely upon the environmental analysis and conclusions of the 2014 Commission Decision with regards to Alternatives and does not need to re-analyze them.

INTRODUCTION

Staff reviewed the 2014 Commission Decision and analyzed the changes to the licensed HBEP, which include:

- Replacing Block 1 with a two-on-one combined-cycle gas turbine (CCGT) configuration,
- Replacing Block 2 as licensed with two simple-cycle gas turbines (SCGT) units,
- Using a natural-gas-fired auxiliary boiler to support the CCGT power block,
- Using a set of natural gas compressors in each power block,
- Constructing other equipment and facilities to be shared by both power blocks,
- Constructing the project on 30 acres within the footprint of the existing Huntington Beach Generating Station (HBGS), and
- Adding a 22-acre area for temporary construction laydown and construction worker parking at the former Plains All-American Tank Farm property.

SUMMARY OF THE DECISION

The list below provides a short summary of the licensed HBEP 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. The evidence establishes an acceptable analysis of a reasonable range of alternatives to the HBEP as proposed.

2. The evidentiary record contains an adequate review of alternative sites, technologies, conservation and demand-side management, and the "no project" alternative.

3. Alternative technologies accomplished fewer of the entire suite of project objectives.

4. No site alternative is capable of meeting the stated project objectives.

5. The "no project" alternative would not provide electrical system benefits, including support for the integration of renewable energy.

6. HBEP is environmentally preferable to other alternatives

7. If all conditions of certification contained in this Decision are implemented, construction and operation of the HBEP will not create any significant direct, indirect, or cumulative adverse environmental.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

Compliance with LORS is not a requirement of an Alternatives analysis.

ENVIRONMENTAL IMPACT ANALYSIS

Staff's alternatives analysis for the modified HBEP is guided in part by CEQA Guidelines section 15126.6(f)(2)(C), which states: "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 EIR 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 modified HBEP proposes to change the licensed HBEP by primarily replacing two independently operating, three-on-one, combined-cycle gas turbine power blocks. As licensed, HBEP is a 939-megawatt (MW) power plant with each power block consisting of three-gas-fired combustion turbine generators (CTG), three supplemental-fired heat recovery steam generators (HRSG), one steam turbine generator (STG), an air-cooled condenser, and related ancillary equipment.

The proposed modified HBEP would replace Block 1 with a two-on-one CCGT configuration consisting of two General Electric (GE) gas turbines and two HRSGs without supplemental firing, a STG, an air-cooled condenser, and related ancillary equipment, with nominal summer capacity of 644 MWs (net). In addition, Block 2 would be replaced with two GE SCGT units with a nominal capacity of 200 MWs.

In addition, the proposed modified HBEP would use a natural-gas-fired auxiliary boiler to support the CCGT power block, use a set of natural gas compressors in each power block, and construct other equipment and facilities to be shared by both power blocks, including water treatment facilities, emergency services, and administration and maintenance buildings. The proposed modified HBEP would be constructed on 30 acres within the footprint of the existing HBGS which includes the licensed 28.6-acre site plus an additional 1.4 acres of paved area previously evaluated as temporary construction parking that the project owner acquired from Southern Californian Edison. Construction of the proposed modified HBEP would also use an additional area for temporary construction laydown and construction worker parking at the former Plains All-American Tank Farm property to the southeast of the licensed site. As part of the proposed modified HBEP, a total of 22 acres of combined construction parking and construction laydown is proposed at the Plains All-American site, whereas the licensed HBEP included 1.9 acres of construction parking on the Plains All-American Tank Farm site.

ALTERNATIVE SITES EVALUATION

The 2014 Decision concluded the location of the licensed HBEP cannot vary substantially from the HBGS site and established a firm connection between the licensed HBEP project and the existing HBGS. The 2014 Decision concluded any alternative site would require conversion of some other area of similar acreage to a new electrical power generation facility. AES owns and has full access to the HBGS site and no other site is identified where the project applicant could reasonably acquire site access to allow the timely completion of necessary environmental reviews, permitting, and approvals. The Decision questioned the ability of developing a different site that could meet the project objectives and questioned whether any off-site alternative would allow the project to remain a viable project given the likely extreme project schedule delay that would accompany a change of project site. The 2014 Decision concluded that alternative site evaluation was not required for the licensed HBEP. These circumstances remain substantially the same for the amended HBEP and, therefore, there is no need to reconsider alternative sites.

ALTERNATIVE SITE CONFIGURATIONS

The 2014 Decision evaluated the potential to reconfigure the project elements on the HBGS site to avoid or lessen noise, visual, and coastal impacts. The Decision concluded reconfiguring the site layout would not significantly lessen or avoid any operational noise impacts. Regarding visual impacts, the Decision concluded moving the visually prominent structures within the HBGS site would not reduce their visibility from sensitive viewpoints to any great extent and would not significantly lessen or avoid visual impacts. Related to coastal resources, the Decision concluded impacts identified in a report by the California Coastal Commission on the licensed HBEP primarily relating to Land Use, Noise and Vibration, and Visual Resources, would not be significantly lessened or avoided by reconfiguration of the project site (CCC 2014).

These circumstances remain substantially the same for the amended HBEP and, therefore, there is no need to reconsider alternative site configurations.

ALTERNATIVE GENERATION TECHNOLOGY

The 2014 Decision evaluated primarily whether alternative generation technologies would reduce air quality impacts of the licensed HBEP. The technologies evaluated included conventional boiler and steam turbine, simple-cycle combustion turbine, alternate equipment, renewable resources, and recycled water.

The conventional boiler and steam turbine technology was eliminated from further consideration because this technology would not qualify for the South Coast Air Quality Management District's Rule 1304 exemption for emissions offsets. Simple-cycle combustion turbine was eliminated from further consideration because it would not reduce or avoid any impacts associated with implementing the licensed HBEP. Alternate equipment was eliminated from further consideration because it would not meet all of the project objectives. Renewable resources were eliminated from further consideration because they were found to be infeasible. Recycled water was eliminated from further consideration because it was found to be infeasible for the cooling demand of the licensed HBEP and for its unavailability to replace once-through-cooling (OTC). These circumstances remain substantially the same for the amended HBEP and, therefore, there is no need to reconsider alternative generation technologies.

CLUTCHES AND SYNCHRONOUS CONDENSERS

Clutches were not proposed in this petition to amend, and therefore were not reviewed for impacts. However, recent Energy Commission project siting committees have asked whether and when clutches could be installed, and what that would mean for the project's impacts. California has a large, geographically diverse, interconnected generation system. Ancillary services in support of the grid, such as voltage and frequency regulation, sometimes called volt-ampere reactive (var), can be provided incidentally when generators are online providing capacity and energy (megawatts and megawatt hours - MW and MWhr, respectively), or through dedicated equipment including synchronous condensers or capacitors. On November 23, 2015, the California Independent System Operator (CAISO) sent a letter to the California Public Utilities Commission (CPUC) with a copy provided to the Energy Commission (CAISO 2015a). The CAISO recommended that the clutch technology that allows fossil fuel-fired generation units to operate temporarily as synchronous condensers be considered as a "default option in procurement decisions" by the CPUC.

The clutch allows a generator to disconnect from its prime mover (e.g., combustion or steam turbine) and synch up to the electricity grid to provide voltage and frequency support. The clutches are commercially available, as are the controls to synch and control the generator as it operates as a synchronous condenser. The clutches and controls are feasible on a variety of turbines, and appear on a small number of California combustion turbines. However, they are not generally used by California utilities to provide the ancillary services they potentially offer. To date, only Los Angeles Department of Water and Power is using clutches it has recently installed to operate the associated generators as synchronous condensers. Two legacy steam turbine generators, Huntington Beach Generating Station Units 3 are 4, are now operating as synchronous condensers. The shafts to the steam turbine were permanently disconnected, avoiding the need for a clutch. New equipment was added to ramp up, sync, and control the synchronous condenser operations, and some form of a contract is in place to pay for the services provided.

Because vars do not travel well it may be most efficient, as described in other reports by the CAISO and as seen in activities in SCE and San Diego Gas and Electric, to install stand-alone voltage support components at a time and very specific location they are needed. This may be a moving target as the system integrates 33 percent and then to 50 percent renewable generation. The relative costs of achieving voltage support with clutches should be compared to other measures (ranging from developing stand-alone equipment, distributed generation, demand-side measures, batteries, storage, to electrifying the transportation sector). Further, as the system evolves, certain assets will become “stranded” to a degree that they can offer fewer services to the grid, or that portion of the grid needs fewer services. Adding features to a new turbine generating unit may appear efficient, but could result in a more expensive/multipurpose facility, but stranded asset none the less.

Potential Clutch Installation at the Amended HBEP

There would be five turbine generators at the amended HBEP – two CTGs and one STG in the combined-cycle Power Block 1 and two CTG peakers in Power Block 2. While there appears to be the potential to deploy this technology at the amended HBEP, the use, and any potential system or environmental benefits realized, of this technology at a given power plant occurs only when:

1. There is a need for location specific ancillary/grid support services;

2. The plant is not needed for (a) energy or (b) ancillary services other than voltage support, if provision of these services requires the plant to be operating and producing energy. When needed for energy or spinning reserve, the generator and engine are connected and the plant is producing energy and providing voltage support; the fact that it *can* provide the latter without generating energy is irrelevant at that point in time; and,

3. The synchronous condenser is needed for voltage support but the energy and capacity not provided by the plant are provided by a plant *that is more efficient/lower emitting than the local plant that it replaces.* Reliance on a synchronous condenser to provide the needed voltage support would require replacing the energy it would have provided; while the replacement energy might be cleaner (e.g., from a renewable generator), it might not, depending on load levels, time of day, etc.

For the amended HBEP Power Block 1 combined-cycle unit, it is unlikely that any of the three turbine generators would be candidates for clutches, for the following reasons:

- Combined cycles are more efficient than simple-cycle peakers, and therefore they may already be online and operating and providing incidental ancillary services along with the contracted real power (MW and MWhrs). In other words, if already operating, there would be no opportunity or need to operate as an independent synchronous condenser, as laid out in Number 2 above.
- Combined cycles are generally designed for optimum performance at expected or contracted operations obligations. Therefore, the project owner needs, or prefers, to have the combined cycle available to operate when required. If operating as a synchronous condenser prevents or limits the responsiveness to dispatch requests, the project owner may be penalized or miss revenue opportunities.
- In California, air regulations do not permit the turbine exhaust bypass of the oxidation and selective catalytic reduction catalysts located in the heat HRSGs, so either the HRSG has to be designed to operate "dry" or the cooling tower has to be sized large enough to take all the steam dumped from the HRSG if the steam turbine is taken off line via a clutch.

For the two simple-cycle CTGs in the amended HBEP Power Block 2, there would be the potential to install and use clutches because:

- The same GE LMS100 CTGs planned for the amended HBEP have been recently delivered and are operating in California with clutches; and,
- The petitioner has indicated there is adequate space (about 20 feet) to insert a clutch unit between the combustion turbine and the generator.

However, the technical feasibility does not answer:

- Whether there is a need for such ancillary services at this location;
- Whether there is a need for such ancillary services at this location once the proposed efficient, flexible, dispatchable combined cycle is constructed and operating;
- If the petitioner could negotiate satisfactory terms with the CTG vendor that would warranty the CTG with the clutch installed and in use; and,
- How a power purchase agreement would be crafted to allow the petitioner to install and operate the clutch and control equipment while recovering costs?

In other words, technical feasibility does not address the questions of need, function, or economics. The determination of the need for vars would be no different than the consideration of need for capacity or real power – determining whether or not vars are needed at a location would be outside the Energy Commission's siting purview.

Potential Effects of Clutch Installation

In this petition, there may be an opportunity well after the Decision is finalized for the local utility and the project owner to agree on var procurement from the proposed simple-cycle CTGs in Power Block 2. This would occur before the two simple-cycle CTGs are purchased and installed. Staff does not believe it is workable to put in a place-holder-shaft in a gap left for the clutch. The place-holder, or extended shaft, would have to be supported, making it nearly as complicated and expensive as the clutch itself. Staff agrees that the decision about the clutch should be made when the CTG unit is "spec'ed" for purchase. Further, while staff believes an amendment to the Decision would be required, it would be a simple amendment and would likely not result in significant impacts. Staff does not recommend fully analyzing the clutch now as we believe it to be speculative (the project owner does not have a contract for peaker services, much less, for ancillary services that would be provided by a clutch and synchronous condenser controls).

The clutch and its housing for an LMS100 CTG are about 20-feet long but no taller or wider than the combustion turbine or generator housings it would be located between. It would require a foundation. But given the site is a brown field site, staff does not foresee any significant impacts (e.g., no additional noise, no new visual impacts, manageable biological or cultural effects, no additional water use or storm water impact, no change in unit availability or reliability, etc.) from the installation and operation of a clutch/synchronous condenser. Staff agrees that losses would be negligible, but losses none the less, from having to spin up and overcome friction in the clutch and its bearings. This could result in additional fuel use and emissions, or a loss of output and efficiency, at the amended HBEP. Staff believes the changes would be small.

There would also be some electricity demand from the grid to keep the generator synched to the grid (again, how that electricity would be fed back from the grid, and paid for, would have to be laid out in a contract for the ancillary services). However, the amount of electricity is low, about 1 percent of the generator rating (or 1 MW for the LMS100 nominal 100 MW generator). The CAISO is the agency primarily responsible for determining the need for voltage support in the balancing authority area, as well as the impact and effectiveness of existing or proposed resources in its provision. In comments on the need for, and impact of installing synchronous condenser technology at the Amended Carlsbad Energy Center Project site, it stated:

"The [CPUC's] Alternate Proposed Decision includes language directing SDG&E to study the addition of synchronous condenser technology, commonly referred to as a "clutch," at the Carlsbad Energy Center facility. In response to the Alternate Proposed Decision, the CAISO analyzed both peak forecast and lower load level scenarios to test whether the addition of synchronous condenser technology could enable a reduction in the amount of gas-fired generation (and associated emissions) that the Carlsbad Energy Center would otherwise be expected to produce. In recent years, the CAISO has approved significant upgrades to the Southern California transmission system to address reactive power needs and will continue to update and evaluate the adequacy of these solutions in future planning studies. The CAISO targeted these upgrades at locations that were both highly electrically efficient and feasible at times of peak system loading with some locations having expansion capabilities for even more reactive support should it become necessary. Due to the specific circumstances of localized voltage stability, the thermal limitations in the area, and the development of better-situated synchronous condensers in the area, the CAISO has not been able to confirm that the synchronous condenser technology at Carlsbad would enable any material reduction in gas-fired generation output. Assuming that the transmission system upgrades and [CPUC]-authorized procurement are realized in a timely manner, <u>synchronous condenser technology at the Carlsbad Energy Center may not provide material emission reduction benefits [emphasis added].</u> Therefore, based on a preliminary analysis, the CAISO has not been able to identify significant benefits to the installation of synchronous condenser technology at the Carlsbad Energy Center." [1]

Avoided emissions (i.e, emissions savings that arise when the plant would not otherwise be operating) are complex given the interconnectedness of the modern grid. If the amended HBEP operates and thus also provides ancillary services, a unit elsewhere in the grid does not have to operate and its potential emissions may be avoided. However, if the amended HBEP operates as a synchronous condenser, it still uses some nominal amount of electricity, and the emissions associated with the generation of that small amount of electricity would occur. Further, the electricity that would have been provided by the amended HBEP now has to be generated elsewhere on the grid. Obviously, the hope is that the ancillary services allow import of "emissionless" renewable generation. However, that is not certain, so the avoided emissions cannot be counted on.

PREFERRED RESOURCES

The 2014 Commission Decision considered "preferred resources," including energy efficiency and demand response programs, and concluded they were not alternatives to the HBEP. Staff has augmented the discussion of preferred resources in this Alternatives analysis for the amended HBEP.

[1] *Comments of the California Independent System Operator Corporation on Alternative Proposed Decision*, filed in California Public Utilities proceeding A.14-07-009, April 27, 2015.

Several large aging power plants on the Southern California coast are retiring during 2017 – 2020 as a result of the State Water Resources Control Board's policy to reduce the biological impacts of once-through cooling. These plants are located in transmission-constrained areas in which threshold amounts of generation capacity are needed to ensure that standards for reliable system operation are met. Accordingly, in its 2012 Long-term Procurement Planning (LTPP) proceeding, the CPUC considered the need for replacement of natural gas-fired generation capacity. It found a need for 1,000 MWs of such capacity in the CAISO-defined Los Angeles Basin area and authorized SCE to procure it (CPUC 2013a). SCE entered into a contract with the HBEP to meet a share of this authorization/need, and applied for recovery of costs incurred under the contract. This application was approved on November 19, 2015 (CPUC 2015).

State policy includes a *loading order* for electric generation that prefers and maximizes cost-effective, reliable, and feasible energy efficiency, demand response programs and measures, and renewable generation to supplant the need for new fossil fuel generation. These "preferred resources" can and do provide services that may obviate the need for natural gas-fired generation, and the CPUC imposes the loading order on utility procurement (Pub. Utilities Code, § 454.5(b)(9)(C)). In authorizing the procurement of new natural gas-fired generation capacity in the Los Angeles Basin, however, the CPUC found that at least 1,000 MWs of capacity with the characteristics of natural gas-fired generation were needed in the area, and that cost-effective preferred resources in amounts that would reduce this capacity need below 1,000 MWs could not feasibly or reliably be developed. Its decision also required SCE to demonstrate that all cost-effective preferred resources offered in response to a Request for Offers in the western Los Angeles area were procured by the utility.

The HBEP and the Reliable Operation of the Electricity System

In May 2010, the State Water Resources Control Board (SWRCB) adopted a statewide *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy). The OTC Policy requires existing power plant operators to implement measures to reduce impingement mortality and entrainment of marine life, and established compliance deadlines. In light of likely compliance by the owners of OTC units by shutting them down, and the large amount of OTC capacity in transmission-constrained areas in Southern California, the CPUC devoted a share of the 2012 LTPP proceeding (CPUC 2012a) to consideration of the potential need for new natural gas-fired generation to meet local reliability requirements in the CAISO defined Los Angeles Basin, San Diego, and Big Creek - Ventura areas. Such generation, if necessary, would be required to meet reliability standards imposed by the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC), which require load to be served in the areas under once-in-ten-year demand conditions even after the sequential failure of two major system components (generation units and transmission lines).

The CPUC authorized SCE to procure between 1,400 MWs – 1,800 MWs of new resource capacity in the West Los Angeles sub-area of the CAISO-defined Los Angeles Basin Local Reliability Area (CPUC 2013a). This was done to maintain reliability after the expected retirement of 14 units at four generation facilities in the sub-area (Alamitos, El Segundo, Huntington Beach and Redondo Beach), totaling 4,386 MWs of capacity, on or prior to December 31, 2020, pursuant to compliance deadlines set forth in the OTC policy. The MWs authorized were largely based on CAISO testimony in the form of a local capacity technical study of capacity needed in the West Los Angeles sub-area over a ten-year planning horizon to meet the NERC and WECC standards discussed above (CPUC 2013a, pp. 15-16). Of this capacity, at least 1,000 MWs, but no more than 1,200 MWs was required to be from conventional gas-fired resources (p. 131); the remaining capacity was to come from preferred resources. A subsequent decision (CPUC 2014a) in the same proceeding considered additional capacity needs potentially arising from the retirement of the San Onofre Nuclear Generating Station, and increased the ceiling on new conventional gas-fired generation capacity to 1,500 MWs.

On November 21, 2014, SCE submitted an application to the CPUC to approve the recovery of costs incurred in entering into a contract with AES for the development of the HBEP, selected by SCE pursuant to a Request for Offers to provide a share of the authorized capacity. CPUC approved SCE's request (CPUC 2015).

Preferred Resources as Substitutes for Dispatchable Natural Gas-Fired Generation

The state's loading order established by the energy agencies in 2003 calls for meeting new electricity needs first with efficiency and demand response (jointly, demand-side management), followed by renewable energy and distributed generation, and only then with efficient utility-scale natural gas-fired generation. Section 454.5(b)(9)(C) of the California Public Utilities Code addresses requirements for an electrical corporation's proposed procurement plan, including the requirement to "first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." In recent years, energy storage has achieved preferred resource status due to its ability to (a) absorb over-generation that may occur at high levels of solar penetration and, (b) reduce the need for natural gas-fired generation and associated capacity to meet ramping needs during evening hours when solar resource output declines to zero.

Preferred resources can provide many of the services provided by dispatchable, natural gas-fired generation. The ability of individual resources (energy efficiency, demand response, utility-scale and distributed renewable generation, and storage) to provide specific services is discussed below.

Energy Efficiency

Energy efficiency entails using less energy to provide the same service such as by improving the efficiency of air conditioners or the insulation characteristics of building shells, thereby using less energy to keep the temperature of a building at desired levels. Continued development and implementation of comprehensive, long-term energy efficiency strategies and programs remains the top priority to offset increased energy demand. The CPUC oversees the investor-owned utilities (IOU) energy efficiency programs, and many of the state's municipal utilities administer similar programs. These efforts are funded by ratepayers and include a wide variety of initiatives aiming to move energy-efficient equipment and effective energy management practices into the marketplace at increasing scale. The CPUC issues decisions approving the electric energy efficiency budgets for the state's IOUs. For 2013–2015, the approved electricity energy efficiency budgets for the state's three major IOUs total $2.388B (CPUC 2012b, pp. 102-103; CPUC 2014b, pp. 104-105).

SB 350 (2015) reflects California's commitments to energy efficiency in its efforts to transition to a low-carbon economy. The bill requires the Energy Commission to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings by January 1, 2030, and requires the CPUC (for investor-owned utilities) and local publicly owned utilities to establish efficiency targets consistent with this goal.

Energy efficiency programs can serve as substitutes for dispatchable, natural gas-fired generation such as the HBEP by: (1) reducing the amount of electricity that needs to be generated when targeted at consumption during high-demand hours and when flexible generation is needed most, and (2) reducing the need for natural gas-fired generation capacity, as well as the need for load-serving entities to procure such capacity to satisfy CAISO- and CPUC-imposed system-wide resource adequacy requirements. In targeting consumption in the western Los Angeles sub-area, energy efficiency programs can reduce the need for conventional generation in the area and the need to procure such capacity to satisfy resource adequacy requirements for local (Western Los Angeles) and flexible resources. Energy efficiency programs are thus capable of reducing the need for energy and capacity-related reliability services that conventional natural gas-fired generation such as the HBEP would provide.

Demand Response

Demand response (DR) programs provide an economic incentive for end-users to modify energy use, whether through direct payments to reduce consumption when requested to do so (i.e., event-triggered DR programs) or rate structures that encourage reducing energy use during hours in which generation is expensive and/or system reliability is threatened. On September 25, 2013, the CPUC authorized a new rulemaking (R.13-09-011), in part, to facilitate the participation of aggregated loads in ancillary service markets, allowing them to directly compete with generation resources in providing reliability services and to satisfy resource adequacy requirements imposed on load-serving entities in exchange for a stream of revenue (CPUC 2013b).

DR continues to play an important role in meeting California's capacity planning, including requirements for peak summer demand. These programs are operated by the state utilities; DR programs operated by the IOUs meet roughly 5 percent of total CAISO system resource adequacy capacity requirements (CAISO 2015, pg. 25). DR has attributes that can partially meet some of the HBEP's project objectives by: (1) contributing to or reducing the need for capacity-related reliability services, including an array of ancillary services (regulation and spinning reserves), and (2) reducing the need for flexible generation if called upon during hours in which ramping needs are highest. When such programs reduce loads in the western Los Angeles area, they reduce local capacity requirements. DR programs can facilitate the integration of renewable resources by meeting incremental needs for regulation and reserves and reducing ramping needs. Unlike gas-fired generation, DR can absorb load during periods of renewable over-generation.

Utility-Scale and Distributed Renewable Generation

California's transition to a low-carbon economy requires dramatically reducing greenhouse gas (GHG) emissions from the electricity sector, in turn allowing other economic sectors (e.g., transportation, industry) to transition from fossil fuels to electricity as a primary fuel source. A primary vehicle for reducing sectorial GHG emissions is the state's Renewable Portfolio Standard (RPS), which requires that providers of retail electricity procure a minimum share of energy (measured as a percentage of retail sales) from renewable sources. SB 1078 (2002) established an RPS of 20 percent by 2017; SB 107 (2006) accelerated the RPS to 2010. SB 2 then increased the RPS to 33 percent by 2020. Finally, SB 350 (2015) increased it to 50 percent by 2030. It is estimated that an amount equal to 25 percent of their retail sales was procured by California load-serving entities from renewable sources in 2014.

In 2010, Governor Brown's Clean Energy Jobs Plan established a target of 12,000 MWs of renewable distributed generation (DG) by 2020. As of October 31, 2015, 7,200 MWs of renewable DG was operational, contracts with another 900 MWs had been approved, and 2,200 MWs of capacity was anticipated from various incentive programs (the Renewable Auction Mechanism, Renewable Feed-in Tariff, the Bioenergy Feed-in Tariff, and utility PV programs).[2]

Utility-scale and distributed renewable generation substitute for natural gas-fired generation as sources of energy. To the extent that they can be relied upon to produce that energy during periods of peak or high demand, they are also substitute sources of capacity, thereby reducing the need to build and operate gas-fired generation. When located in transmission-constrained areas such as the Western Los Angeles sub-area, they can provide local capacity, reducing the need to build and operate local natural gas-fired generation, such as the HBEP.

[2] http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf

Energy Storage

As California increasingly relies on wind and solar resources to meet its energy needs and environmental goals, other energy resources are increasingly called upon to "balance the system." Expected changes in wind and solar output over the course of a day and random swings due to changing weather conditions both become larger, requiring more flexible, dispatchable natural gas-fired generation to be built and operated to compensate for the variations in wind and solar output.[3]

Mature, utility-scale technologies include pumped hydro and compressed air storage; several pumped hydro facilities have been operating in California for decades; the 1,212 MWs Helms facility has been operated by PG&E since 1984.

California recognized the key role that storage will play in integrating wind and solar resources in a "high variable energy" system in setting an ambitious target for the procurement of energy storage capacity for 2020. On October 17, 2013 (CPUC 2013c), the CPUC established a target of 1,325 MWs, apportioning it to the transmission and distribution systems and the customer side of the meter.

Storage cannot replace generation as a source of energy as it requires injections of energy in excess of the amounts that are discharged when the stored energy is needed. It can however, replace generation capacity, being charged during non-peak hours and discharged on-peak – in lieu of dispatching natural gas-fired generation. If located in a transmission-constrained area, storage can replace generation capacity needed for local reliability.

Preferred Resources are not an Alternative to the HBEP

The CPUC found that at least 1,000 MWs of dispatchable, natural-gas fired generation resources are needed in the Western Los Angeles sub-area for local reliability:

> *"The record shows that the most certain technology which can meet LCR [local capacity requirement] needs (from the ISO's perspective) is gas-fired generation. In order to ensure a base level of procurement certain to ensure reliability under the most stringent criteria, we will require that at least 1,000 MWs in the LA basin local area be from gas-fired generation.* (CPUC 2013a, p. 81)*."*

Selected preferred resources *might* meet the CAISO's criteria for contributing to local reliability; the CPUC has found that this possibility should be considered by the CPUC and discussed in SCE's application to procure specific resources:

[3] In some systems (in the Pacific Northwest, for example), there is sufficient dispatchable hydro to balance a wind- and solar-intensive generation fleet. The scale of wind and solar development in California, however, is such that energy storage is expected to absorb surplus generation during mid-day hours, as well as use energy generated during the day to reduce the need for energy and capacity from natural gas-fired generation resources during evening hours.

> *“The ISO finds that gas-fired generation meets its criteria [for the provision of local reliability services], as well as any other resources (or combination of resources) which have the same performance criteria as gas-fired generation. Demand response resources and CHP [combined heat and power] may meet the ISO’s criteria, but not at this time. It is possible that other resources will pass the ISO test as well in the future. Of course, acquisition of more energy efficiency and demand side resources would reduce the LCR need* (CPUC 2013a, pp. 74-75).”

> *“We will require SCE to consult with the ISO regarding ISO performance characteristics (such as ramp-up time) for local reliability. In its application to procure specific resources to meet local reliability needs (discussed herein), SCE shall provide documentation of such efforts and how SCE meets ISO performance requirements* (CPUC 2013a, p. 75).”

Section 454.5(b)(9)(C) of the California Public Utilities Code addresses requirements for an electrical corporation’s proposed procurement plan, including the requirement to “first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible. These requirements were restated in the decision to authorize natural gas-fired generation in the Western Los Angeles sub-area:

> *SCE’s procurement plan shall be consistent to the extent possible with the multi-agency Energy Action Plan, which places cost-effective energy efficiency and demand response resources first in the Loading Order, followed by renewable resources and then fossil-fuel resources. Energy storage resources should be considered along with preferred resources* (CPUC 2013a, p. 3).

> *As part of our review of SCE’s procurement plan, and when considering SCE’s procurement application, we will require SCE to show that it has done everything it could to obtain cost-effective demand-side resources which can reduce the LCR need, and cost-effective preferred resources and energy storage resources to meet LCR needs.* (CPUC 2013a, p. 78)

A substantial share of the testimony and subsequent discussion in the 2012 LTPP proceeding was devoted to determining the appropriate assumptions for the development of preferred resources in the Western Los Angeles sub-area over the planning horizon, which, in turn, largely determined the need for natural gas-fired generation in the area. Given that approval of a procurement plan requires that it be consistent with the Loading Order, the CPUC effectively found that preferred resources beyond those procured by SCE in response to its RFO cannot feasibly and reliably be counted upon to cost-effectively meet local reliability needs (CPUC 2015).

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 is to consider the events or actions reasonably expected to occur in the foreseeable future would occur if the project were not approved, based on current plans and consistent with available infrastructure and community services (Cal. Code Regs., tit. 14, § 15126.6(e)(2)). For the purposes of this analysis, the no project alternative is considered to be the construction and operation of the previously licensed HBEP in the 2014 Commission Decision.

The licensed HBEP was found to have significant but mitigable impacts in all resource areas. In comparison, the amended HBEP would not result in any new or increased significant environmental impacts in all resource areas. In addition, the “no project” alternative would not meet the project objective to align the licensed HBEP with the project configuration directed by the CPUC in its approval of the power purchase agreement between SCE and AES.

CONCLUSIONS AND RECOMMENDATIONS

In accordance with CEQA Guidelines section 15126.6(f)(2)(C), staff reviewed alternatives previously analyzed for the licensed HBEP design and related facilities, alternative technologies, and the “no project” alternative. Alternatives previously found to be infeasible would not now be feasible, and would not substantially reduce one or more significant effects of the licensed HBEP. Similarly, new information does not show alternatives which are considerably different from those analyzed in the previous staff assessment for the licensed HBEP that would substantially reduce one or more significant effects on the environment. Therefore, staff concludes that no supplementation to the 2014 Commission Decision is necessary for Alternatives. The Committee may rely upon the environmental analysis and conclusions of the 2014 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 2014 Commission Decision.
- The circumstances under which the modified HBEP would be undertaken would not require major revisions of the Alternatives analysis in the 2014 Commission Decision.

Staff’s conclusion is supported by the fact that the Decision for the licensed HBEP contains an acceptable analysis of a reasonable range of alternatives to the project and contains an adequate review of alternative project sites, alternative site configurations, alternative generation technology, and the “no project” alternative.

REFERENCES

AES 2015 - *Petition to Amend Huntington Beach Energy Project (12-AFC-02C)*. September 14, 2015.

CAISO 2015 - California ISO, State of California, *2015 Summer Loads and Resources Assessment*, pg. 25. May 7, 2015.

CAISO 2015a - California ISO, State of California, Letter from CAISO President Steve Berberich to CPUC President Michael Picker, November 23, 2015. TN206824

CCC 2014 - California Coastal Commission, *Coastal Commission's 30413(d) Report for the proposed AES Southland, LLC, HBEP AFC*, July 14, 2014. TN202701

CEC 2014 - California Energy Commission, State of California, *Huntington Beach Energy Project, Final Decision (Order No. 14-1029-1)*. November 2014.

CPUC 2012a - California Public Utilities Commission, *Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios.* R.12-03-014, December 20, 2012.

CPUC 2012b - California Public Utilities Commission, *Decision Approving 2013-2014 Energy Efficiency Program and Budgets.* D.12-11-015, November 8, 2012.

CPUC 2013a - California Public Utilities Commission, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements.* D.13-02-015, February 13, 2013.

CPUC 2013b - California Public Utilities Commission, *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.* R.13-09-011, September 25, 2013.

CPUC 2013c - California Public Utilities Commission, *Decision Adopting Energy Storage Procurement Framework and Design Program.* D.13-10-040, October 17, 2013.

CPUC 2014a - California Public Utilities Commission, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements Due to Permanent Retirement of the San Onofre Nuclear Generation Station*. D.14-03-004, March 13, 2014.

CPUC 2014b - California Public Utilities Commission, *Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Program and Budgets (Concludes Phase I of R.13-11-005)*. D.14-10-046, October 16, 2014.

CPUC 2015 - California Public Utilities Commission, *Decision Approving, in Part, Results of Southern California Edison Company Local Capacity Requirements Request for Offers for the Western LA Basin Pursuant to Decisions 13-02-015 and 14-03-004*. D.15-11-041 and A.14-11-012. November 19, 2015.

Compliance Conditions and Compliance Monitoring Plan

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02C)
Petition to Amend Final Commission Decision
COMPLIANCE CONDITIONS AND COMPLIANCE MONITORING PLAN
Eric Veerkamp

~~VII.COMPLIANCE CONDITIONS AND~~
~~COMPLIANCE MONITORING PLAN~~

In this section, changes from the 2014 Commission Decision are shown in ~~strikethrough~~ for deleted text and **bold underline** for new text.

~~Public Resources Code section 25532 requires the Commission to establish a post-certification monitoring system. The purpose of this requirement is to assure that certified facilities are constructed and operated in compliance with applicable laws, ordinances, regulations, standards, as well as the specific Conditions of Certification adopted as part of this Decision.~~

~~SUMMARY AND DISCUSSION OF THE EVIDENCE~~

~~The record contains a full explanation of the purposes and intent of the Compliance Plan (Plan). The Plan is the administrative mechanism used to ensure that the HBEP is constructed and operated according to the Conditions of Certification. It essentially describes the respective duties and expectations of the Project Owner and the Staff Compliance Project Manager (CPM) in implementing the design, construction, and operation criteria set forth in this Decision. (Ex. 2000, pp. 7-3 – 7-5.)~~

~~Compliance with the .Conditions of Certification contained in this Decision is verified through mechanisms such as periodic reports and site visits. The Plan also contains requirements governing the planned closure, as well as the unexpected temporary and unexpected permanent closure, of the Project. (Ex. 2000, p. 7-1.)~~

~~The Compliance Plan is composed of two broad elements. The first element establishes the "General Conditions" (referred to as "Compliance and Closure" in Appendix A) that set forth:~~

- ~~the duties and responsibilities of the Compliance Project Manager (CPM), the project owner, delegate agencies, and others;~~
- ~~the requirements for handling confidential records and maintaining the compliance record;~~
- ~~the procedures for settling disputes and making post-certification changes;~~
- ~~the requirements for periodic compliance reports and other administrative procedures necessary to verify the compliance status of all Commission imposed Conditions; and~~
- ~~set forth requirements for facility closure.~~

~~(Ex. 2000, pp. 7-3 – 7-7.)~~

~~The second general element of the Plan contains the specific "Conditions of Certification". These are found following the summary and discussion of each individual topic area in this Decision. The individual Conditions contain the measures required to mitigate potentially adverse Project impacts associated with construction, operation, and closure to levels of insignificance. Each Condition also includes a verification provision describing the method of assuring that the Condition has been satisfied. (Ex. 2000, pp. 7-7 – 7-8.)~~

~~The contents of the Compliance Plan are intended to be implemented in conjunction with any additional requirements contained in the individual Conditions of Certification.~~

~~CALIFORNIA COASTAL COMMISSION COMMENTS~~

~~The Coastal Commission submitted a report dated July 14, 2014, entitled, " Coastal Commission's 30413(d) Report for the proposed AES Southland, LLC, HBEP AFC" (July 2014 Report). (Ex. 4026.) For the Commission's detailed analysis of the July 2014 Report, please see the **LAND USE** section of this Decision.~~

~~The July 14 Report included extensive comments on potential impacts on environmentally sensitive habitats from groundwater, including construction dewatering. The Coastal Commission recommends that the Conditions of Certification require AES to conduct a geotechnical investigation that identifies expected dewatering volumes and the spatial extent of drawdown expected from that dewatering. If the investigation shows potential drawdown effects to nearby environmentally sensitive habitats or wetland areas, project owner would then be required to identify and implement methods to avoid those effects. The methods to mitigate the potential effects of dewatering include installing sheet piles, slurry walls, or other similar barriers or conducting alternative dewatering methods that would avoid drawing down groundwater in these sensitive areas. The Coastal Commission also recommends that these structural mitigation methods be included on any relevant final design plans required pursuant to this Decision. (Ex. 4026, pp 13 – 14.)~~

~~We agree that these modifications to Condition of Certification **GEN-2** are appropriate and should be included in similar Conditions of Certification, such as **SOIL&WATER-1, SOIL&WATER-3, SOIL&WATER-4,** and **BIO-7**. With the imposition and implementation of these Conditions of Certification, we have provided additional feasible mitigation measures to avoid potential adverse dewatering impacts to adjacent habitat areas.~~

~~PUBLIC COMMENT~~

~~There were no public comments on Compliance and Closure.~~

~~HUNTINGTON BEACH ENERGY ROJECT~~
~~(12-AFC-02) CONDITIONS OF CERTIFICATON~~

~~DEFINITIONS~~

~~DEF-1. DEFINITIONS~~

~~The following terms and definitions apply to all of the Conditions of Certification in this Appendix "A".~~

~~1. Project Certification~~

~~Project certification occurs on the day the Energy Commission dockets s Decision.~~

~~2. Site Assessment and 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 shall not affect listed or special-status species or other sensitive resources:~~

- ~~the installation of environmental monitoring equipment;~~
- ~~a minimally invasive soil or geological investigation;~~
- ~~a topographical survey;~~
- ~~any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility; and~~
- ~~any minimally invasive work to provide safe access to the site for any of the purposes specified in 1-4, above.~~

~~3. Site Mobilization and Construction~~

~~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:~~

- ~~ground disturbance activities like grading, boring, trenching, leveling, mechanical clearing, grubbing, and scraping;~~
- ~~site preparation activities, such as access roads, temporary fencing, trailer and utility installation, construction equipment installation and~~

~~storage, equipment and supply laydown areas, borrow and fill sites, temporary parking facilities, and chemical spraying and controlled burns; and~~

- ~~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.~~

~~4. System Commissioning and Decommissioning~~

~~Commissioning activities are designed to test the functionality of a facility's installed components and systems to ensure safe and reliable operation. Although decommissioning is often synonymous with facility closure, specific decommissioning activities also systematically test the removal of such systems to ensure a facility's safe closure.~~

~~For compliance monitoring purposes, commissioning activities include interface connection and utility pre-testing, "cold" and "hor electrical testing, system pressurization and optimization tests, grid synchronization, and combustion turbine "first fire." Decommissioning activity examples include utility shut down, system depressurization and de-electrification, structure removal, and site reclamation.~~

~~5. Start of Commercial Operation~~

~~For compliance monitoring purposes, "commercial operation" or "operation" begins once commissioning activities are complete, the certificate of occupancy has been issued, and the power plant has reached reliable steady-state electrical production. Operation activities can include a steady state of electrical production.~~

~~6. Non-Operation~~

~~Non-operation is time-limited and can encompass part or all of a facility. Non-operation can be a planned event, usually for minor equipment maintenance or repair, or unplanned, usually the result of unanticipated events or emergencies.~~

~~7. Closure~~

~~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.~~

~~8. Measurement.~~

~~Whenever distance is used in these Conditions of Certification, It shall be measured from the project fence line.~~

INTRODUCTION

The Huntington Beach Energy Project (HBEP) 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 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, 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

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, 12-AFC-2C) 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 or "operation" begins once commissioning activities are complete, the certificate of occupancy has been issued, and the power plant has reached reliable steady-state electrical production. At the start of commercial operation, plant control is usually transferred from the construction manager to the plant operations manager. Operation activities can include a steady state of electrical production, or, for "peaker plants," a seasonal or on-demand operational regime to meet peak load demands.

NON-OPERATION AND CLOSURE

Non-operation is time-limited and can encompass part or all of a facility. Non-operation can be a planned event, usually for 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 HBEP project.

COMPLIANCE PROJECT MANAGER RESPONSIBILITIES

The CPM's compliance monitoring and project oversight responsibilities include:

1. ensuring that the design, construction, operation, and closure of the project facilities are in compliance with the terms and conditions of the Decision;

2. resolving complaints;

3. processing post-certification project amendments for changes to the project description, conditions of certification 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 PTA 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 during project pre-construction, construction, operation, emergency response, and closure. The CPM will consult with the appropriate responsible parties when handling compliance issues, disputes, complaints and amendments.

All project compliance submittals are submitted to the CPM for processing. Where a submittal requires CPM approval, required by a condition of certification requires CPM approval, the approval will involve appropriate Energy Commission technical staff and management. All submittals must include searchable electronic versions (.pdf, MS Word, or equivalent files).

Pre-Construction and Pre-Operation Compliance Meeting

The CPM usually schedules pre-construction and pre-operation compliance meetings prior to the projected start-dates of construction, plant operation, or both. These meetings are used to assist the Energy Commission and the project owner's technical staff in the status review of all required pre-construction or pre-operation conditions of certification, and 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 not delay the construction and operation of the plant due to last minute~~,~~ unforeseen issues or a compliance oversight. Pre-construction meetings held during the certification process must be publicly noticed unless they are confined to administrative issues and processes.

Energy Commission Record

The Energy Commission maintains the following documents and information as public record, in either the Compliance file or Dockets Unit files, for the life of the project (or other period as specified):

- all documents demonstrating compliance with any legal requirements relating to the construction, operation, and closure of the facility;

- all Monthly and Annual Compliance Reports (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

The project owner is responsible for ensuring that all conditions of certification and applicable LORS in the HBEP 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 HBEP 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. The California Office of Administrative Law provides on-line access to the California Code of Regulations at http://www.oal.ca.gov/.

INFORMAL RESOLUTION PROCESS

Issues related to the construction or operation of a licensed facility should be directed to the CPM who will act as the point person in working with the public and project owner to resolve these concerns.

The CPM can initiate meetings with stakeholders, investigate the facts surrounding the issues, obtain information from the facility owner, work with staff to review documents and information, issue reports and facilitate solutions to issues related to the construction and operation of the facility.

Contacting the CPM seeking an informal resolution may precede the formal Request for Investigation procedure specified in Title 20, California Code of Regulations, section 1231, but is not intended to be a prerequisite or requirement to utilizing the Request for Investigation process. The informal resolution process encourages all parties to openly discuss the conflict and reach a mutually agreeable solution.

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 may work to informally resolve a dispute between the parties, or 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, section 1231.

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 amend the Final Commission Decision in order 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 PTA 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.

<u>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.</u>

~~COMPLIANCE AND CLOSURE~~

COMPLIANCE CONDITIONS OF CERTIFICATION

Compliance ~~Conditions~~~~Table~~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 ~~such condition was~~**the conditions were** satisfied **directly** by ~~work performed or~~ the project owner or ~~his~~**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 **C**ompliance **C**onditions of **C**ertification.
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 ~~Monthly Compliance Reports.~~**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.**

Condition Number	Subject	Description
COM-11	Reporting of Complaints, Notices, and Citations	Prior to the start of construction, the project owner shall provide all property owners within a ~~1~~**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 ~~10~~**ten** days of receipt, the project owner shall report to the CPM all notices, complaints, violations, and citations.
COM-12	Site Contingency Plan	No less than 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 ~~unanticipated event or~~ emergency.
COM-13	Incident-Reporting Requirements	The project owner shall notify the CPM within **one (**1**)** hour of an incident and submit a detailed incident report within ~~30 days~~**(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 ~~2 weeks~~**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 ~~60 days after initiating commercial operation~~**the first ACR**, the project owner shall submit a Provisional Closure Plan ~~and Cost Estimate~~ for permanent closure. ~~At least 3 years~~**No less than one (1) year** prior to closing, the project owner shall submit a Final Closure Plan and Cost Estimate.

For the HBEP project, staff proposes the Compliance Conditions of Certification below. Changes from the October 29, 2014 Commission Decision are shown in ~~strikethrough~~ for deleted text and bold underline for new text. COM-6 has been modified to more clearly state the continuing submittal requirements for MCR's. COM-7 was modified pertaining to submittal of PCR's and due dates. COM-10 has been updated to include information about recently adopted application and processing fees for Post Certification Amendments and Changes, ref. Public Resources Code Section 25806 (e). COM-11 has been updated to incorporate a number of administrative changes to reporting complaints, notices and citations. COM-12 has been modified as to the required submittal of updates to the Contingency Plan. COM-13 has been updated to reflect revised incident reporting requirements. COM-15 has been updated to reflect revised procedures for preparing a final closure plan and estimating costs.

COM-1 **Unrestricted Access**. The project owner shall take all steps necessary to ensure that the CPM, responsible Energy Commission staff, and ~~delegated~~ **delegate** agencies or consultants~~,~~ have unrestricted access to the facility site, related facilities, project-related staff, and the records maintained on-site **for the purpose of conducting** ~~to facilitate~~ audits, surveys, inspections, ~~and~~ **or** general or closure-related site visits. Although the CPM ~~shall~~ **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. The files shall alsocontain at least one hard copy of:

1. the facility's Application~~(s)~~ 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**~~.~~ Verification lead times associated with the start of construction ~~or closure~~ may require the project owner to file submittals during the ~~AFC~~ **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.**

A cover letter from the project owner or an authorized agent is required for all compliance submittals and correspondence pertaining to compliance matters. The cover letter subject line shall identify the project by AFC number, cite the appropriate condition~~(s)~~ of certification number(s), and give a brief description of the subject of the submittal. When submitting supplementary or corrected information, the project owner shall reference the date of the previous submittal and the condition(s) of certification applicable.

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~~ the actions required by the verification were satisfied 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 address as follows:

Compliance Project Manager
Huntington Beach Energy Project (12-AFC-2C)
California Energy Commission
1516 Ninth Street (MS-2000)
Sacramento, CA 95814

COM-4~~:~~ **Pre-Construction Matrix and Tasks Prior to Start of Construction**. Prior to ~~start of~~ construction, the project owner shall submit to the CPM a compliance matrix including only those conditions that must be fulfilled before the start of construction. The matrix 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.

Site mobilization and construction activities shall not start until ~~all of~~ the following ~~occur: the~~**have occurred:**

1. The project owner has submitted the pre-construction matrix and all ~~submittals required by~~ compliance verifications pertaining to ~~all~~ pre-construction conditions of certification~~,~~**;** and ~~the~~

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 ~~staff~~ 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 ~~verification requirement~~**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.

COM-5 **Compliance Matrix**. The project owner shall submit a compliance matrix to the CPM with each MCR and ACR.~~The compliance matrix provides the CPM with the status of all conditions of certification in a spreadsheet format~~ The compliance matrix shall identify:

1. the technical area (e.g., biological resources, facility design, etc.);
2. the condition number;
3. a brief description of the verification action or submittal required by the condition;
4. the date the submittal is required (e.g., ~~sixty~~ **(**60**)** days prior to construction, after final inspection, etc.);
5. the expected or actual submittal date;
6. the date a submittal or action was approved by the **Delegate Chief Building Official (D**CBO**),** CPM, or delegate agency, if applicable;
7. the compliance status of each condition (e.g., "not started," "in progress" or "completed" (include the date); and
8. if the condition was amended, the updated language and the date the amendment was proposed or approved.

The CPM can provide a template for the compliance matrix upon request.

COM-6 **Monthly Compliance Report** ~~Reports and Key Events List.~~ The first MCR is due one (1) month following the docketing of the project's Decision unless otherwise agreed to by the CPM. The first MCR shall include the AFC number and an initial list of dates for each of the events identified on the Key Events List. (The Key Events List form is found at the end of this Compliance Plan.)

During ~~project~~ pre-construction, construction, or closure~~,~~ the project owner or authorized agent shall submit an electronic searchable version of the MCR **to the CPM** within ten (10) business days after the end of each reporting month~~unless otherwise specified~~**. MCRs shall be submitted each month until construction is complete and the final certificate of occupancy is issued** by the ~~CPM~~**DCBO**. MCRs shall be clearly identified for the month being reported~~. The searchable electronic copy may be filed on an electronic storage medium or by e-mail, subject to CPM approval. The compliance verification submittal condition provides guidance on report production standards, and the~~**The** 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 MCR~~ each~~. **Each** of these items shall be identified in the transmittal letter, as well as the conditions they satisfy, and submitted as attachments to the MCR;
3. an initial, and thereafter updated, compliance matrix showing the status of all conditions of certification;
4. a list of conditions that have been satisfied during the reporting period, and a description or reference to the actions that satisfied the condition;
5. a list of any submittal deadlines that were missed, accompanied by an explanation and an estimate of when the information will be provided;
6. a cumulative listing of any approved changes to ~~the~~ conditions of certification;
7. a ~~list~~**listing** of any filings submitted to, and permits issued by, other governmental agencies during the month;
8. a projection of project compliance activities scheduled during the next **(2)** two months~~.~~; the project owner shall notify the CPM as soon as any changes are made to the project construction schedule that would affect compliance with conditions of certification;
9. a ~~list~~**listing** of the month's additions to the on-site compliance file; and

10. 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.**

COM-7 **Periodic and Annual Compliance Reports**. After construction is complete, the project~~ owner~~ must submit searchable electronic ACRs ~~instead of MCRs.~~**to the CPM, as well as other periodic compliance reports (PCRs) required by the various technical disciplines.** ACRs ~~are due~~ **shall be completed** for each year of commercial operation and ~~may be required~~ ~~for~~**are due each year on** a ~~specified period after~~**date agreed to by the CPM**. **Other PCRs (e.g. quarterly reports or** decommissioning **reports** to monitor closure compliance ~~as~~**), 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 ~~showing~~**which shows** the status of all conditions of certification (fully satisfied conditions do not need to be included in the matrix after they have been reported as completed);

2. a summary of the current project operating status and an explanation of any significant changes to facility operations during the year;

3. documents required by specific conditions to be submitted along with the ACR; each of these items shall be identified in the transmittal letter with the ~~condition~~**conditions** it satisfies~~,~~ and submitted as an ~~attachmen~~**attachments** to the ACR;

4. a cumulative ~~list~~**listing** of all post-certification changes approved by the Energy Commission or the CPM;

5. an explanation for any submittal deadlines that were missed, accompanied by an estimate of when the information will be provided;

6. a ~~list~~**listing** of filings submitted to, ~~and~~**or** permits issued by, other governmental agencies during the year;

7. a projection of project compliance activities scheduled during the next year;

8. a ~~list~~**listing** of the year's additions to the on-site compliance file;

9. an evaluation of the Site Contingency Plan, including amendments and plan updates; and

10. a ~~list~~**listing** of complaints**, incidents**, notices of violation, official warnings, and citations received during the year, a description of how the issues were resolved, and the status of any unresolved ~~matters~~**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 ~~shall~~**will** remain undisclosed, as provided in Title 20, California Code of Regulations, section 2501.

COM-9 **Annual Energy Facility Compliance Fee**. Pursuant to the provisions of section 25806 (b) of the Public Resources Code, the project owner is required to pay an annually adjusted compliance fee. Current compliance fee information is available on the Energy Commission's website 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.

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.

~~Implementation of a project modification without first securing Energy Commission, or Energy Commission staff, approval may result in an enforcement action, including civil penalties, in accordance with section 25534 of the Public Resources Code. If the Energy Commission's rules regarding amendments are revised, the rules in effect at the time the change is requested shall apply.~~

~~Com~~**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.

COM-11 Reporting of Complaints, Notices, and Citations. Prior to the start of construction or ~~decommissioning~~**closure**, the project owner shall send a letter to property owners within one (1) mile of the project, notifying them of a telephone number to contact project representatives with questions, complaints~~,~~ or concerns. If the telephone is not staffed ~~twenty-four (~~24~~)~~ hours per day, it ~~shall~~**must** include automatic answering with ~~a~~ date and time stamp recording.

The project owner shall respond to all recorded complaints within ~~twenty-four~~ 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 ~~who will post it on the Energy Commission's web page at: http://www.energy.ca.gov/sitingcases/huntington_beach_energy/index.html. The project owner shall~~**and promptly** report any disruption to the contact system or telephone number change to the CPM~~promptly~~, **who will provide it** to **any persons contacting him or her with a complaint.**

~~In addition to including all complaints, notices, and citations included with the MCRs and ACRs, within ten (10~~**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.**

COM-12 Emergency Response Site Contingency Plan. No less than ~~sixty (~~60~~)~~ days prior to the start of ~~commercial operation~~**construction** (or other **CPM-approved** date~~agreed to by the CPM),~~ 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 ~~the updating of the~~ Contingency Plan **updating** over the life of the facility. Contingency Plan elements include, but are not limited to:

1. ~~a~~**A** site-specific list and direct contact information for persons, agencies, and responders to be notified for an unanticipated event;

2. ~~a~~**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~~**A** detailed and labeled map of population centers, sensitive receptors, and the nearest emergency response facilities;

4. ~~a~~**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~~**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~~**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~~**Procedures** for maintaining contingency response capabilities; and

8. ~~the~~**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**).~~ **Public Health, Waste Management, Hazardous Materials Management, and Worker Safety).**

COM-13 Incident-Reporting Requirements. ~~Within one hour after it is safe and feasiblethe~~**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) Megawatts **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 ~~and safety~~ impacts ~~on~~**to** the surrounding population~~;property damage~~**or any release that could result in an** off-site~~;~~ **odor issue;**

~~3.~~

~~4. serious environmental damage; or~~

3. ~~emergency reporting to~~ **Notification to or** response by **any** off-site emergency response~~agencies;serious on-site injury; any~~ **, 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**).~~ **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 ~~twenty four (~~24~~)~~ hours of a request.

COM-14 Non-Operation and Repair/Restoration Plans. If the facility ceases operation temporarily~~ either~~(excluding planned ~~and unplanned~~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. **I**dentification of operational and non-operational components of the plant;
2. ~~a~~**A** detailed description of the repair **and inspection** or restoration activities;
3. ~~a~~**A** proposed schedule for completing the repair **and inspection** or restoration activities;
4. **A**n 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. **P**lanned 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. **P**rogress relative to the schedule;
2. **D**evelopments that delayed or advanced progress or that may delay or advance future progress;
3. **A**ny public, agency, or media comments or complaints; and

4. **P**rojected date for the resumption of operation.

During non-operation, all applicable conditions of certification and reporting requirements remain in effect. If, after one (1) year from the date of the project owner's last report of productive Repair/Restoration Plan work, the facility does not resume operation or does not provide a plan to resume operation, the Executive Director may assign suspended status to the facility and recommend commencement of permanent closure activities. Within ~~ninety (~~90~~)~~ days of the Executive Director's determination, the project owner shall do one of the following:

1. If the facility has a closure plan, the project owner shall update 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.

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~~and Estimate of Permanent Closure Costs~~

To assure satisfactory long-term site maintenance and adequate closure for "the whole of a project," the project owner shall ~~submi~~**include within the first ACR** a Provisional Closure Plan ~~and Cost Estimate~~ for CPM review and approval.~~within sixty (60) days after the start of commercial operation.~~ The **CPM may require** Provisional Closure Plan ~~and Cost Estimate~~**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~~ the use of an independent third party to~~**that qualified personnel will** carry out~~ the~~ permanent closure **and long-term maintenance activities.**

The Provisional Closure Plan **shall reflect the most current regulatory standards, best management practices,** and ~~Cost Estimate shall~~**applicable LORS, and** provide for a phased closure process and include but not be limited to:

1. comprehensive scope of work~~and itemized budget;~~

~~2. closure plan development costs;~~

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.

~~The project owner shall include an updated Provisional Closure Plan and Cost Estimate in every fifth-year ACR for CPM review and approval. Each updated Provisional Closure Plan and Cost Estimate shall reflect the most current regulatory standards, best management practices, and applicable LORS.~~

B. Final Closure Plan and Cost Estimate

~~At least three (3) years~~**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, ~~post-closure~~ 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 revised/updated~~**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 ~~delegate CBO's~~**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 ~~or listserv~~**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~~**PUBLIC HEALTH, WASTE MANAGEMENT, HAZARDOUS MATERIALS MANAGEMENT, AND WORKER SAFETY**).

If ~~implementation of an~~the Energy Commission-approved Final Closure Plan and Cost Estimate ~~is~~**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, ~~or subsequently abandons the facility, the Final Closure Plan and Cost Estimate shall be resubmitted to the Commission for supplementary review and approval~~ **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.

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 ~~TL~~ **Transmission Line** Construction	
Complete Transmission Line Construction	
Synchronization with Grid and Interconnection	
~~Complete T/L Construction~~	
FUEL SUPPLY LINE ACTIVITIES	
Start Gas Pipeline Construction and Interconnection	
Complete Gas Pipeline Construction	
WATER SUPPLY LINE ACTIVITIES	
Start Water Supply Line Construction	
Complete Water Supply Line Construction	
Start Recycled Water Supply Line Construction	
Complete Recycled Water Supply Line Construction	

ATTACHMENT A
COMPLAINT REPORT AND RESOLUTION FORM

COMPLAINT LOG NUMBER:______________________________ DOCKET NUMBER:____________

PROJECT NAME:____

COMPLAINANT INFORMATION

NAME:____ PHONE NUMBER:______________________________

ADDRESS:____

COMPLAINT

DATE COMPLAINT RECEIVED:_________________________ TIME COMPLAINT RECEIVED:__________________

COMPLAINT RECEIVED BY: __________________________ ☐ TELEPHONE ☐ IN WRITING (COPY ATTACHED)

DATE OF FIRST OCCURRENCE:_______________________

DESCRIPTION OF COMPLAINT (INCLUDING DATES, FREQUENCY, AND DURATION):__________________________

____

____

FINDINGS OF INVESTIGATION BY PLANT PERSONNEL:____

____

____

DOES COMPLAINT RELATE TO VIOLATION OF A CEC REQUIREMENT? ☐ YES ☐ NO

DATE COMPLAINANT CONTACTED TO DISCUSS FINDINGS:____

DESCRIPTION OF CORRECTIVE MEASURES TAKEN OR OTHER COMPLAINT RESOLUTION:____________________

____

____

DOES COMPLAINANT AGREE WITH PROPOSED RESOLUTION? ☐ YES ☐ NO

IF NOT, EXPLAIN:____

____

CORRECTIVE ACTION

IF CORRECTIVE ACTION NECESSARY, DATE COMPLETED:____

DATE FIRST LETTER SENT TO COMPLAINANT (COPY ATTACHED):_____________________________________

DATE FINAL LETTER SENT TO COMPLAINANT (COPY ATTACHED):_____________________________________

OTHER RELEVANT INFORMATION:____

____

____

"This information is certified to be correct."

PLANT MANAGER SIGNATURE:_______________________________________ DATE: _______________

ATTACHMENT A
COMPLAINT REPORT~~/~~ AND RESOLUTION FORM

(ATTACH ADDITIONAL PAGES AND ALL SUPPORTING PHOTO/DOCUMENTATION, AS REQUIRED)

Preparation Team

HUNTINGTON BEACH ENERGY PROJECT PETITION TO AMEND (12-AFC-02C)
PRELIMINARY STAFF ASSESSMENT
PREPARATION TEAM

Executive Summary .... John Heiser, AICP

Introduction .... John Heiser, AICP

Project Description .... John Heiser, AICP

Environmental Assessment

Air Quality .... Wenjun Qian, Ph. D., P.E., David Vidaver

Biological Resources .... Tim Singer and Heather Blair

Cultural Resources .... Melissa Mourkas and Gabriel Roark

Hazardous Materials Management .... Brett Fooks, PE and Geoff Lesh, PE

Land Use .... Steven Kerr

Noise and Vibration .... Edward Brady

Public Health .... Huei-An (Ann) Chu, Ph. D.

Socioeconomics .... Lisa Worrall

Soil and Water Resources .... Mike Conway

Traffic and Transportation .... John Hope and Wenjun Qian, Ph.D., P.E.

Transmission Line Safety and Nuisance .... Obed Odoemelam

Visual Resources .... Jeanine Hinde and Wenjun Qian, Ph.D., P.E.

Waste Management .... Ellen Townsend-Hough

Worker Safety and Fire Protection .... Brett Fooks, PE and Geoff Lesh, PE

Engineering Assessment

Facility Design .... Shahab Khoshmashrab

Geology and Paleontology .... Mike Conway

Power Plant Efficiency .... Edward Brady

Power Plant Reliability .... Edward Brady

Transmission System Engineering .... Laiping Ng and Mark Hesters

Alternatives .... John Hope, Matthew Layton, and David Vidaver

Compliance Conditions and Compliance Monitoring Plan .... Eric Veerkamp

Project Assistant .... Marichka Haws