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HUNTINGTON BEACH ENERGY PROJECT

Preliminary Staff Assessment - Part B
Supplemental Focused Analysis

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HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02)
PRELIMINARY STAFF ASSESSMENT – Part B

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Felicia Miller

INTRODUCTION

This Preliminary Staff Assessment (PSA) Part B is being published by the California Energy Commission staff for the Huntington Beach Energy Project (HPEB) and contains the remainder of staff's preliminary, independent, objective evaluation of the HBEP Application for Certification (12-AFC-2) that was not covered in Part A. This PSA Part B includes analyses in the following technical areas: **AIR QUALITY, PUBLIC HEALTH AND ALTERNATIVES**.

PSA Part A was published on October 20, 2013, and includes staff's environmental and engineering evaluation of the following technical areas: **BIOLOGICAL RESOURCES, CULTURAL RESOURCES, EFFICIENCY, FACILITY DESIGN, GEOLOGY AND PALEONTOLOGY, HAZARDOUS MATERIALS, LAND USE, RELIABILITY, SOCIOECONOMICS, SOILS AND WATER, TRAFFIC AND TRANSPORTATION, TRANSMISSION SYSTEM ENGINEERING, TRANSMISSION LINE SAFETY AND NUISANCE, VISUAL RESOURCES, WASTE MANAGEMENT, AND WORKER SAFETY AND FIRE PROTECTION**. In addition to the technical areas noted in PSA Part A, PSA Part A also included the following sections which are not included in PSA Part B; **INTRODUCTION, PROJECT DESCRIPTION, AND COMPLIANCE CONDITIONS**.

Staff published a PSA Part A - Focused Staff Analysis (FoSA) on December 20, 2013 which discussed comments received on the HBEP, as well as certain issues discussed at the November 20, 2013 PSA workshop held in Huntington Beach. The FoSA included technical areas: **BIOLOGICAL RESOURCES, CULTURAL RESOURCES, LAND USE, NOISE AND VIBRATION, SOCIOECONOMICS, SOILS AND WATER, VISUAL RESOURCES, AND WASTE MANAGEMENT**.

Generally, the PSA examines engineering, environmental, public health, and safety aspects of the proposed HBEP project, based on the information provided by the applicant, government agencies, interested parties, independent research, and other sources available at the time the PSA was prepared. The PSA contains analyses similar to those normally contained in an Environmental Impact Report (EIR) required by the California Environmental Quality Act (CEQA). When issuing a license, the Energy Commission is the lead state agency under CEQA and its process is functionally equivalent to the preparation of an EIR.

The Energy Commission staff has the responsibility to complete an independent assessment of the project's engineering design and identify the potential impacts on the environment, the public's health and safety, and determine whether the project conforms to all applicable laws, ordinances, regulations and standards (LORS). Upon identifying any potentially significant environmental impacts, staff recommends mitigation measures in the form of conditions of certification for construction, operation and eventual closure of the project.

This PSA is not a decision document for these proceedings, nor does it contain findings of the Energy Commission related to environmental impacts or the project's compliance with local, state, and federal LORS. The PSA will serve as a precursor to the Final Staff Assessment (FSA). After allowing for a public comment period on this PSA, staff will prepare and publish a Final Staff Assessment that will serve as staff's formal testimony in evidentiary hearings to be held by the Energy Commission Committee assigned to hear this case. The Committee will hold evidentiary hearings and will consider the recommendations presented by the staff, applicant, intervenors, government agencies, and the public, prior to proposing its decision. The Energy Commission will make the final decision, including findings, after the Committee's publication of its proposed decision.

PROPOSED PROJECT LOCATION AND DESCRIPTION

The proposed HBEP would be developed by AES Southland Development, LLC on a 28.6 acre site located at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (PCH-Highway 1) and Newland Street. The site is privately owned land located in an industrial area of Huntington Beach, California 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 site is currently occupied by the existing and operational Huntington Beach Generating Station (HBGS), which would be demolished and replaced with the HBEP. The proposed HBEP would be built entirely within the footprint of the HBGS.

The project consists of two power blocks, each composed of three natural gas combustion turbine generators with supplemental fired heat recovery steam generators, a steam turbine generator, and air-cooled condenser. Each power block would have the ability to generate power from 110 MW to 470 MW, is designed to start and stop very quickly, and to quickly ramp up and down.

The new HBEP facility would be air-cooled, eliminating the need for large quantities of once-through cooling seawater. The 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 HBEP. Alternative water sources, including potential use of reclaimed water to support the HBEP, are continuing to be analyzed. 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 currently proposed as part of this project. The HBEP would connect the nominal 936 MW of electricity through two overhead 230-kV generation ties connecting each power block to the existing onsite Southern California Edison (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.

SUMMARY OF PROJECT-RELATED IMPACTS

Based upon the information provided, discovery achieved and analyses completed to date, with exceptions described below, staff concluded that the project complies with all law, ordinances, regulations and standards (LORS), and with the implementation of its recommended mitigation measures described in the conditions of certification, potential environmental impacts of the HBEP project would be mitigated to levels of less than significant.

Executive Summary
Summary of HBEP PSA Technical Analyses

Technical Area	Complies with local, state and federal LORS	Impacts mitigated to level below significant
Air Quality	NO	no
Alternatives	n/a	n/a
Biological Resources	YES	YES
Cultural Resources	YES	YES
Efficiency	YES	YES
Facility Design	yes	yes
Geology and Paleontology	yes	yes
Hazardous Materials Management	yes	yes
Land Use	UNDETERMINED	UNDETERMINED
Noise and Vibration	YES	YES
Public Health	YES	yes
Reliability	yes	yes
Socioeconomic Resources	yes	yes
Soil & Water Resources	yes	yes
Traffic and Transportation	yes	yes
Transmission Line Safety/Nuisance	yes	yes
Transmission System Engineering	undetermined	undetermined
Visual Resources	undetermined	undetermined
Waste Management	yes	yes
Water Resources	yes	yes
Worker Safety / Fire Protection	yes	yes

Air Quality – Staff has included Conditions of Certification **AQ-SC1** through **AQ-SC5** to implement control measures for short-term 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 HBEP except for PM10 and PM2.5. Staff has worked with the applicant to refine the construction modeling impact assessment, however, the latest modeling still shows that PM10 and PM2.5 impacts during the approximately 90 month project construction period would cause exceedances of health-based ambient air quality standards, and thus, these impacts would be significant. Staff recommends that the applicant continue to refine the modeling, consider staggering construction activities to reduce concurrent emissions, and implement additional mitigation measures to reduce construction emissions and potential impacts. The duration and complexity of construction that contributes to these potential impacts are due in part to the current facility continuing to provide generation and/or reactive power from the site while the new project is being built, commissioned and operated.

Alternatives – In preparation for an alternatives analysis, as the lead agency for CEQA, staff is required to describe a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project; consider alternatives that would avoid or substantially lessen any significant environmental impacts of the project, including alternatives that would be more costly or would otherwise impede the project's objectives, and evaluate the comparative merits of the alternatives.

Staff reviewed the alternatives analysis provided by the applicant, as well as alternatives recommended through agency and public comment, and additional alternatives developed by staff. Staff's Alternatives analysis included an alternative site configuration, technology alternatives, as well as the no project (retrofit of HBGS) alternative. In addition, staff proposed in their Soil and Water Resources section of the Focused Staff Assessment (FoSA) (TN 201463 12/20/13), the recommendation for the project to use recycled water for industrial purposes, so a detailed analysis of recycled water supply is included in the Alternatives section of this PSA Part B.

Staff determined the proposed project has a strong relationship to the existing project site, and given the uncertain potential for development of any alternative site to achieve the project objectives, no alternatives are considered that would entail decommissioning and retiring the existing power plant.

Staff received several comments from the public and agencies asking staff to analyze alternative site configurations for potential noise, visual and coastal impacts. Noise was analyzed and staff determined that even if the proposed project were configured differently, similar temporary construction noise impacts would occur within the project boundary, and no significant construction or operational noise impacts to adjacent receptors (including both residential and biological resources) have been identified that could not be mitigated. Visual impacts would not change as the visual prominence of the air cooled condensers, and other equipment, limit options to reconfigure the project site. Staff has proposed conditions of certification to reduce visual resource impacts to achieve compliance with applicable laws, ordinances, regulations, and standards. Staff has reviewed the proposed HBEP layout and determined that reconfiguring the site layout would not significantly lessen or avoid visual impacts. In addition, staff has determined that reconfiguring the HBEP layout would not significantly lessen or avoid noise or visual impacts on coastal resources.

Generation technology alternatives developed and considered by staff focus on technologies that can utilize natural gas, which can take advantage of the existing natural gas pipeline system and also meet the electrical capacity replacement requirements specified by SCAQMD's Rule 1304. Analysis of conventional boiler and steam turbine technology was eliminated from consideration because it did not qualify for the SCAQMD 1304 exemption for offsets. Use of simple-cycle combustion turbines was also eliminated from consideration, as it would not reduce or avoid any HBEP impacts.

The No Project (retrofit) analysis examined two alternatives considered feasible by staff for complying with the SWRCB's once through cooling (OTC) policy: retrofit with air cooled condenser (ACC) and with wet cooling towers. The retrofit ACC would involve retrofitting Units 1 and 2 with ACC, which would result in the generating station operating at slightly less efficiency than the proposed HBEP. The wet cooling scenario would require Units 1 and 2 to use a new non-seawater source for cooling water. Options include use of recycled water for the makeup cooling water source which would be potentially supplied by the Orange County Sanitation District facilities via a new pipeline to convey the recycled water to the HBGS site, as well as a new water treatment facility constructed at the HBGS. Staff determined this alternative would result in the generating station operating slightly more efficiently than the proposed HBEP.

In staff's Soil and Water Resources section published in the FoSA, staff included a recommendation for the proposed project to use recycled water. Although staff determined potable water use for process and steam makeup for the HBEP would not result in significant impacts, Energy Commission policy directs power generation facilities to utilize recycled water, when feasible. Staff's analysis in this document is cursory, and although it indicates the recycled water alternative is feasible, a more detailed analysis will be included in the Final Staff Assessment.

AIR QUALITY

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

SUMMARY OF CONCLUSIONS

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

Staff concludes that 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 that would fully mitigate emissions of all nonattainment pollutants and their precursors at a minimum ratio of one-to-one and to reduce the potential operational impacts of the proposed project to less than significant.

Staff includes Conditions of Certification **AQ-SC1** through **AQ-SC5** to implement control measures for short-term 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 HBEP except for PM10 and PM2.5. Staff has worked with the applicant to refine the construction modeling impact assessment. However, the latest modeling still shows that PM10 and PM2.5 impacts during the approximately 7.5-year project construction period would cause exceedances of health-based ambient air quality standards and thus these impacts would be significant. Staff recommends that the applicant continue to refine the modeling, consider staggering construction activities to reduce concurrent emissions, and implement additional mitigation measures to reduce construction emissions and 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. Therefore, there would be concurrent operation, demolition, commissioning and construction activities throughout the construction period.

Global climate change and greenhouse gas emissions from the project are discussed and analyzed in **Air Quality Appendix Air-1**. The HBEP would emit approximately 0.479 metric tonnes of carbon dioxide per megawatt hour ($MTCO_2$/MWh), which complies with Greenhouse Gases Emission Performance Standard of 0.5 metric tonnes CO_2 /MWh (Title 20, California Code of Regulations, section 2900 et seq.). Mandatory reporting of the GHG emissions would occur and the Air Resources Board is updating greenhouse gas regulations and a cap–and–trade program for greenhouse gas emissions. The project is expected to be subject to these requirements as the regulations are more fully developed and implemented.

The technical description of the nitrogen deposition analysis for the project is discussed in **Air Quality Appendix Air-2.** Staff used AERMOD to estimate nitrogen deposition impacts from HBEP. Considering the improvement in the nitrogen baseline concentrations in the South Coast Air Basin, and that the project's oxides of nitrogen emissions are fully offset by district's RECLAIM program, staff believes the nitrogen deposition impacts derived from this modeling and described in **BIOLOGICAL RESOURCES** section are conservative, or an upper bound of potential impacts.

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants from both the construction and operation of the proposed HBEP project. The project would be located entirely within the footprint of the existing Huntington Beach Generating Station, an operating power plant. The HBEP is a proposed natural-gas fired, combined-cycle, air-cooled, 939-megawatt (MW) electrical generating facility that would replace the existing Huntington Beach Generating Station.

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, 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 emissions also readily react in the atmosphere to form particulate matter, and are major contributors to acid rain. Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in the context of cumulative impacts (**Air Quality Appendix Air-1**).

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

- Whether the 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 1744 (b));
- Whether the 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 1743); and
- Whether the mitigation measures proposed for the project are adequate to lessen the potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws, ordinances, regulations, and standards (LORS) and policies pertain to the control of criteria pollutant emissions and the mitigation of air quality impacts. Staff's analysis describes or evaluates the project's compliance with these requirements, as in **Air Quality Table 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 NAAQS. A PSD permit would be required for the NOx and VOC because the net emission increase in NOx and VOC would exceed 100 tons per year. 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 District.
Title 40 CFR Part 60, Subpart Da	New Source Performance Standard (NSPS) for Steam Generators: for the fired HRSGs 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 60, Subpart KKKK	New Source Performance Standard (NSPS) for Stationary Combustion Turbines: 15 parts per million (ppm) NOx at 15% O_2 and fuel sulfur limit of 0.060 lb SOx per million Btu heat input.
Title 40 CFR Part 64	Compliance Assurance Monitoring for emission units at major stationary sources required to obtain a Title V permit. The turbines will be subject to emission limits of NOx, CO, VOC, and PM10 if the emissions are greater than the major source thresholds. Control systems are used for NOx, CO, and VOC, but not PM10.
Title 40 CFR Part 72	Acid Rain Program. Requires reductions in NOx and SO_2 emissions, implemented through the Title V

Applicable LORS	Description
	program. Permitting and enforcement are delegated to SCAQMD.
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); 20 CCR §1752, 2300-2309 (CEC & CARB Memorandum of Understanding)	Requires that Energy Commission decision on AFC include requirements to assure protection of environmental quality.
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.
Regulation XIII: New Source Review	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

Applicable LORS	Description
	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 (CO2) emissions from the facility.

SETTING

METEOROLOGICAL CONDITIONS

The climate of the South Coast Air Basin (basin) is strongly influenced by the 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% 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 2013).

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 applicant (HBEP 2013kk). The most predominant annual wind direction at this monitoring site is from the southwest. There are also less frequent southeast winds occurring all year around. The annual calm wind is about 22% and the annual average speed is 1.67 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 National Ambient Air Quality Standards (NAAQS).

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. The 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.

EXISTING AMBIENT AIR QUALITY

The U.S. Environmental Protection Agency (U.S. EPA), California Air Resource Board (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 HBEP project site is located within the South Coast Air Basin and within the SCAQMD. The federal and state attainment status of criteria pollutants in the SCAQMD are summarized in **Air Quality Table 3**.

Meteorological data from the John Wayne Airport station was used for air quality modeling to determine the project impacts. Although the operating monitoring station closest to the proposed site is North Coastal Orange County (Costa Mesa) station, the data from the John Wayne Airport station is more appropriate because 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 less missing data and 4) Costa Mesa data is problematic as the calm winds percentage will vary from 0% to 38% depending on the data processing methods. Background concentrations of O_3, NO_2, SO_2, and CO were determined using North Coastal Orange County monitoring station data. Ambient concentrations of PM10 and PM2.5 are collected from 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	0.075 ppm (147 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 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	24 Hour	—	0.04 ppm (105 µg/m^3)

Pollutant	Averaging Time	Federal Standard	California Standard
(SO_2)	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 μg/m^3	12 μg/m^3
	24 Hour	35 μg/m^{3b}	—
Sulfates (SO_4)	24 Hour	—	25 μg/m^3
Lead	30 Day Average	—	1.5 μg/m^3
	Rolling 3-Month Average	1.5 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 2013a, EPA 2013a
Note: Fourth- highest maximum 8 – hour concentration, averaged over 3 years.
98th percentile of daily maximum value, averaged over 3 years
99th percentile of daily maximum value, averaged over 3 years

AIR QUALITY Table 3
Attainment Status of South Coast Air Quality Management District (SCAQMD)

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	**Nonattainment**
SO_2	Attainment	Attainment

Pollutants	Attainment Status	
PM10	Attainment	**Nonattainment**
PM2.5	**Nonattainment**	**Nonattainment**
Lead	Attainment	Attainment

Source: ARB 2013b, EPA 2013b.

Nonattainment Criteria Pollutants

Air Quality Table 4 summarizes the existing ambient monitoring data for nonattainment criteria pollutants (Nitrogen Dioxide, ozone and particulate matter) collected from 2007 to 2012 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.

Nitrogen Dioxide (NO_2)

Nitrogen oxides (NOx) include nitric oxide (NO) and nitrogen dioxide (NO_2). Approximately 75 to 90% of the NOx emitted from combustion sources is NO. NO is oxidized in the atmosphere to NO_2 by oxygen and ozone. High concentrations of NO_2 usually occur during the fall when atmospheric conditions tend to trap ground-level emissions but lack significant photochemical activitiy due to less sunlight. In the summer, the converion 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), ozone concentrations can remain relatively high.

AIR QUALITY Table 4
Nonattainment Criteria Pollutants Concentrations, 2007-2012 (ppm or µg/m³)

Pollutant	Averaging Time	2007	2008	2009	2010	2011	2012
NO_2 (ppm)	1 hour	0.07	0.08	0.07	0.07	0.06	0.074
NO_2 (ppm)	Federal 1 hour	0.06	-	0.057	0.056	0.053	0.05
NO_2 (ppm)	Annual	0.013	0.013	0.013	0.011	0.01	0.01
Ozone (ppm)	1 hour	0.082	**0.094**	0.087	**0.097**	**0.093**	**0.090**
Ozone (ppm)	8 hour	**0.072**	**0.079**	**0.075**	**0.076**	**0.077**	**0.076**
PM10 (µg/m³)	24 hour	**75**	**62**	**62**	44	43	45
PM10 (µg/m³)	Annual	**30.2**	**29.1**	**30.5**	**22**	**24.2**	**23.3**
PM2.5[a] (µg/m³)	24 hour	**40.8**	**38.9**	34.2	28.3	27.8	26.4
PM2.5 (µg/m³)	Annual	**14.6**	**14.2**	**13**	10.5	11.0	10.4

Source: SCAQMD 2013d, ARB 2013c, EPA 2013c.
Note: [a] The 24-hour PM 2.5 concentrations are the 98th percentile highest daily 24-hour average PM2.5 concentrations during that year.

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 98th percentile of the *daily maximum* 1-hour concentration (i.e., the 8th highest of daily highest 1-hour concentrations). **AIR QUALITY Table 4** shows the maximum 1-hour NO_2 concentrations at the Costa Mesa station. Data from 2007 to 2012 show that NO_2 concentrations measured at this station have never exceeded either the federal or state standards. The SCAQMD is currently designated as unclassified for federal NO_2 standard but nonattainment with state NO_2 standard.

Ozone

Ozone is not directly emitted from staionary 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 $\mu g/m^3$ has never been exceeded at the stations near the project site from 2007 through 2012. However, the CAAQS 24-hour standard of 50 $\mu g/m^3$ has been exceeded during 2007-2009 period. The maximum 24 hour concentration recorded during the analysis period was 75 $\mu g/m^3$ in 2007. The maximum annual concentration was 30.5 $\mu g/m^3$ in 2009. The SCAQMD 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 Long Beach station. The national 24-hour average NAAQS is met if the 3-year average of the 98^{th} percentile concentration is 35 $\mu g/m^3$ or lower. This threshold was exceeded in 2007 and 2008 with the maximum values of 40.8 and 38.9 $\mu g/m^3$. The annual arithmetic means during the 2007-2012 period are below the federal standard of 15 $\mu g/m^3$, but exceed the state standard of 12 $\mu g/m^3$ in several years. For purpose of state and federal air quality planning and permitting, the SCAQMD is nonattainment with both federal and state PM2.5 standard.

Attainment Criteria Pollutants

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 station. These values are well below respective ambient air quality standards.

AIR QUALITY Table 5
Attainment Criteria Pollutants Concentrations, 2007-2012 (ppm)

Pollutants	Averaging Time	2007	2008	2009	2010	2011	2012
CO	1 hour	5	3	3	2	3	2.1
CO	8 hours	3.1	2	2.2	2.1	2.2	1.7
SO_2	1 hour	0.01	0.01	0.01	0.01	0.008	0.006
SO_2	Federal 1 hour	-	-	0.004	0.002	0.005	0.002
SO_2	24 hours	0.004	0.003	0.004	0.002	0.001	0.001

Source: SCAQMD 2013d, ARB 2013c, EPA 2013c.

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.).

PROJECT DESCRIPTION AND PROPOSED EMISSIONS

The proposed HBEP would consist of two three-on-one combined-cycle power blocks. The new stationary sources of emissions in each power block would be three Mitsubishi Power Systems Americas (MPSA) 501DA combustion turbine generators (CTG), coupled with one steam turbine, and an air cooled condenser (HBEP 2012a).

Separate emissions estimates for the proposed project during the construction phase, initial commissioning, and operation are each described next.

PROPOSED CONSTRUCTION EMISSIONS

Construction of the HBEP is expected to take about 90 months, which includes demolition of existing structures and construction of the new electrical generating components. The construction of the HBEP would require removal of the existing Huntington Beach Generating Station's Units 1 through 5. The duration and complexity of construction activities 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. Therefore, there would be concurrent operation, demolition, commissioning and construction activities throughout the construction period.

AIR QUALITY Table 6
Staff-Recommeded Background Concentrations (μg/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	28.3	35	81
	Annual	11.0	12	92
CO	1 hour	3,450	23,000	15
	8 hour	2,444	10,000	24
NO_2	State 1 hour	139	339	41
	Federal 1 hour	105	188	56
	Annual	21	57	37
SO_2	1 hour	26	655	4
	Federal 1 hour	13	196	7
	24 hour	5	105	5

Source: SCAQMD 2013d, ARB 2013c, EPA 2013c 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.

Onsite demolition activities would include the demolition of Units 1, 2 and 5. Demolition of existing Units 3 and 4 is not part of the 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 HBEP. Demolition of existing Unit 5 includes removal of the non-operational Unit 5 peaker unit, the buildings and small tanks associated with Unit 5, and a fuel oil storage tank. Demolition of existing Units 1 and 2 would include an organized, top down dismantling of the existing boiler units, generator, and the common stack. Onsite construction activities would consist of installing six new combined cycle gas turbines, various auxiliary equipment, and administrative structures.

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 HBEP Block 1 and Block 2; and 3) fugitive dust from demolition activities such as the top-down removal of the Unit 1 and 2 common boiler stack and loading waste haul trucks with the generated debris. Construction activities would be scheduled as 10 hours per day, 23 days per month (HBEP2012a).

Estimates for the highest daily emissions and total annual emissions over the 90-month construction period are shown in **Air Quality Table 7**. The maximum daily emissions and monthly emissions are reported during the overlap of Block 1 and Block 2 construction, which is between months 36 to month 45.

AIR QUALITY Table 7
HBEP, Estimated Maximum Construction Emissions

Construction Activity	NOx	VOC	PM10	PM2.5	CO	SOx
Maximum Daily Construction Emissions (lbs/day)	79.5	12.7	28.95	10.29	88.1	0.20
Maximum Monthly Construction Emissions (lbs/month)	1829	291	671	236.6	2026	4.56
Peak Annual Construction Emissions (tons/year)	8.6	1.3	3.03	0.91	9.1	0.02

Source: HBEP 2014a.
Note: Different activities have maximum emissions at different times during the construction period; therefore, total maximum daily, monthly, and annual emissions might be different from the summation of emissions from individual activities.

PROPOSED INITIAL COMMISSIONING EMISSIONS

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.

The applicant expects the total duration of the commissioning period for each block to be up to 180 days. Each turbine needs up to 491 hours of operation to accomplish the various commissioning activities. **Air Quality Table 8** presents the applicant's anticipated maximum commissioning emissions of criteria pollutants for the turbines. Maximum hourly emissions for NOx and CO would occur during steam blow phases. Maximum hourly emissions for VOC would occur in 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.

AIR QUALITY Table 8
HBEP, Maximum Initial Gas Turbine Commissioning Emissions

Commissioning Source	NOx	VOC	PM10/ PM2.5	CO	SOx[a]
Each CTG (lb/hr)	109.7	383.8	9.5	3,169	2.64
Each CTG (tons/commissioning period)	4.1	7	1.5	56	0.53

Source: HBEP2012a, SCAQMD 2014a and independent staff analysis.
Note: [a] Based upon 0.75 gr/100 scf; worst case, short-term sulfur content of natural gas.

PROPOSED OPERATION EMISSIONS

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

- NOx emissions are to be controlled to 2.0 parts per million by volume, dry basis (ppmvd) corrected to 15% oxygen, averaged over any 1-hour period;
- VOC emissions are to be controlled to 2.0 ppmvd with the use of good combustion practices;
- CO emissions are to be controlled to 2.0 ppmvd with the use of good combustion practices and oxidation catalyst;
- PM10/PM2.5 and SOx emissions are to be controlled to the minumum through the exclusive use of natural gas, inlet air filtration and oxidation catalyst system; and
- Average annual emissions are based on 5,900 hours of base load operation without duct burner firing per turbine per year, 470 hours of base load operation with duct

burner firing per turbine per year, and 624 startups and shutdowns per turbine per year. (SCAQMD 2014a)

Air Quality Table 9 lists the maximum hourly emissions from each CTG estimated by the applicant. Emissions for NOx, CO, and VOC during startup and shutdown events would have higher emissions than during normal operation. Therefore the maximum hourly NOx, CO and VOC emissions are based on a turbine cold startup or shutdown. Since PM10/PM2.5 and SOx emissions are proportional to fuel use, PM10/PM2.5 and SOx have higher emissions rates during full-load operation. Therefore the maximum hourly PM10/PM2.5 and SOx emissions are based on each trubine operating at full load with duct burners firing at 32°F ambient temperature.

AIR QUALITY Table 9
HBEP, Maximum Hourly Emissions Rates during Routine Operation (pounds per hour [lb/hr])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Each CTG	25.5	31.8	9.5	115.3	2.64

Source: HBEP2012a, SCAQMD 2014a and independent staff analysis.

Air Quality Table 10 lists maximum allowable daily emissions of the proposed HBEP. The maximum allowable daily emissions for NOx, CO and VOC are based on one cold start, three hot starts, four shutdowns and 18.7 hours of normal operation at 100% load with five hours of duct burner firing. The maximum daily emissions for PM10 and SOx are based on 24 hours of normal operation at 100% load with five hours of duct burner firing.

AIR QUALITY Table 10
HBEP, Maximum Daily Emissions during Routine Operation (pounds per day [lb/day])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Facility Total (Six Turbines)	2,035	1,744	798	3,208	321

Source: HBEP2012a, SCAQMD 2014a and independent staff analysis.

Air Quality Table 11 lists maximum potential annual emissions from the proposed project, based on applicant and district calculations reviewed by staff. The operating profile includes 5,900 hours normal operation without duct burner firing, 470 hours normal operation with duct burner firing, and 624 startups and shutdowns (including 24 cold startups for 36 hours, 150 warm startups for 81.3 hours, 450 hot startups for 243.8 hours and 624 shutdowns for 104 hours) per year.

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

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Facility Total (Six Turbines)	251.0	167.7	99.3	282.8	40.1

Source: HBEP2012a, SCAQMD 2014a and independent staff analysis.

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.

The applicant reported that the maximum ammonia emission of MPSA 501DA turbine is 5 ppmvd @15% O_2 with or without duct burner firing (HBEP 2012a). The SCQMD also requires a maximum ammonia emissions rate of 5 ppm at 15% oxygen by dry volume (ppmvd) in the flue gas (SCAQMD 2014a). Energy Commission staff notes that control systems can be operated and maintained to routinely achieve less than 5 ppmvd @15% O_2 for ammonia slip, as established in the Guidance for Power Plant Siting (ARB 1999). Staff recommends that the Energy Commission impose a 5 ppm at 15% oxygen by dry volume ammonia limit on this project.

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 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 the Best Available Control Technology (BACT) and emission reduction credits (ERC) or other valid emission reductions to mitigate emissions of both 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 diluted 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. For the HBEP, the surface meteorological data used as an input to the dispersion model included five years (2008-2012) of meteorology data from John Wayne Airport monitoring station.

The applicant conducted the air dispersion modeling based on guidance presented in the *Guideline on Air Quality Models* (EPA, 2005) and the American Meteorological Society/Environmental Protection Agency Regulatory Model known as AERMOD (version 12345). The U.S. EPA designates AERMOD as a “preferred” model for refined modeling in all types of terrain. For determining NO_2 impacts of short-term emissions (1-hour averaging period), NO_2 concentrations were determined using the Ambient Ratio Method (ARM) with NO_x to NO_2 ambient ratio of 0.8.

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 and 24-hour PM2.5 standards are statistically based (i.e., the three year average of the 98th percentile values cannot exceed the applicable limit). In order to demonstrate compliance with these standards, the modeled impacts from the project were added to hourly background concentrations conservatively derived from the measured ambient background levels. The resulting impacts were then evaluated following 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 applicant and, as necessary, independently assessed by Energy Commission staff. The ambient air quality impacts are modeled using AERMOD. Construction modeling for HBEP used five years of meteorological data (2008-2012 from John Wayne Airport station) prepared by SCAQMD.

Air Quality Table 12 summarizes the results of the modeling analysis for construction activities. 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
HBEP, Construction-Phase Maximum Impacts (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	35.8	45	**80.8**	**50**	**162**
	Annual	9.75	**24.2**	**33.95**	**20**	**170**
PM2.5	24 hour[a]	11.0	28.3	**39.3**	**35**	**112**
	Annual	2.71	11.0	**13.71**	**12**	**114**
CO	1 hour	112	3,450	3,562	23,000	15
	8 hour	93.2	2,444	2,537.2	10,000	25
NO_2 [b]	State 1 hour	91.7	139	230.7	339	68
	Federal 1 hour[c]	-	-	183	188	97
	Annual	7.33	21	28.33	57	50
SO_2	State 1 hour	0.22	26	26.22	655	4
	Federal 1 hour[d]	0.22	13	13.22	196	7
	24 hour	0.04	5	5.04	105	5

Source: HBEP 2014a with independent staff analysis.
[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 maximum modeled concentration paired with the 3-year average of 98th percentile seasonal hourly 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.

Staff believes that particulate matter emissions from construction would cause a significant impact because they would cause new violations or contribute to existing violations of PM10 and PM2.5 ambient air quality standards over the fairly extended construction period, and additionally that 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 exceed the most restrictive annual PM10 standard of 20 μg/m^3 while the 24-hour PM10 standard and both the annual and 24-hour PM2.5 ambient background levels are close to their respective standard. Staff has worked diligently with the applicant to reduce the modeled construction impacts, including using more updated meteorological data, refining emissions calculations and the modeling, especially for PM10 and PM2.5. **Air Quality Table 13** shows the history of the construction modeling revisions. The modeling results have been improved significantly from those in the original AFC. However, according to the latest modeling results (dated 01/2014), the project would still cause the PM2.5 standards and 24 hour PM10 standard to be exceeded and contribute to the existing violation of annual PM10 standard.

To determine worst-case impacts for both 24-hour and annual averages, the modeling assumes that the maximum emission rates occur during the entire 90-month construction period. However, maximum emissions are only expected to occur over a relatively short portion of the 90-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 90-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 are above the significant level during almost the entire construction period. Therefore, PM10 emissions could cause exceedances of the 24-hour standard and thus create significant impacts during most of the 90-month construction period.

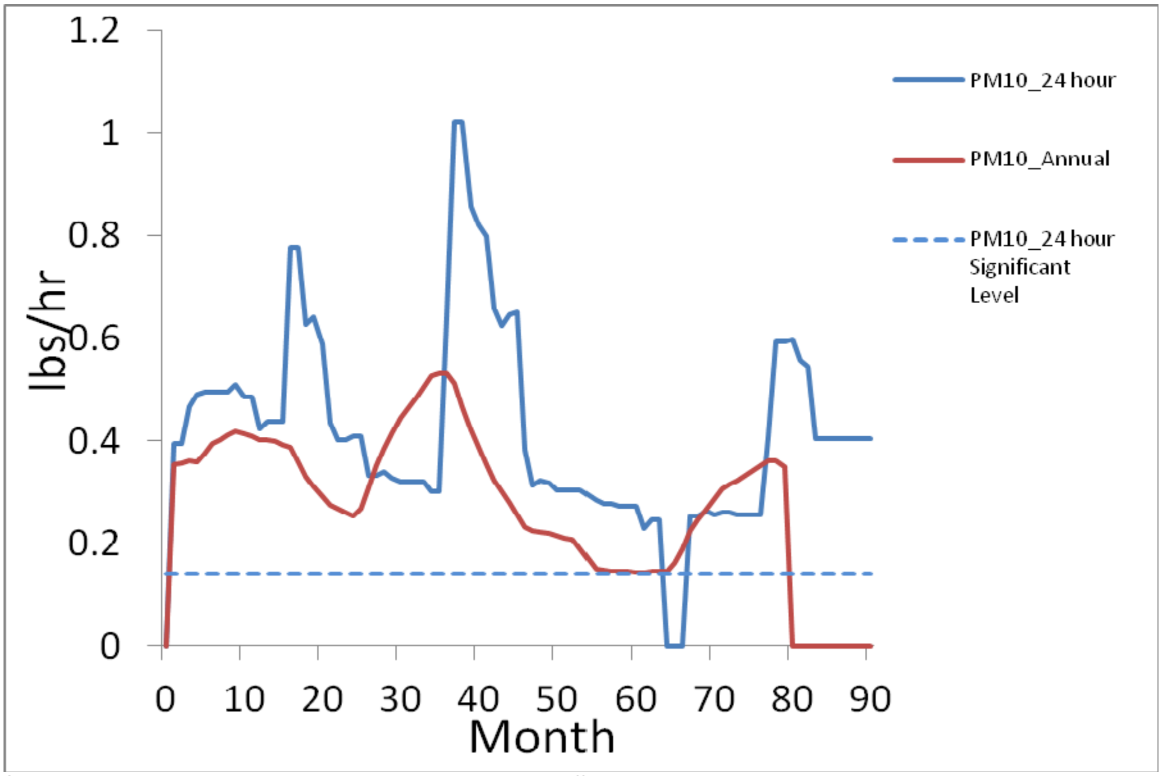
The anticipated PM2.5 emission rates are shown in **Air Quality Figure 1b**. PM2.5 emissions, when added to the relatively high 24-hour averaged background levels at the site, would lead to impacts that would be above the 24-hour standard during months 16 to 19 and months 37 to 41. The annual PM2.5 emission 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 1 to 45 (nearly 4 years) and months 67 to 79 (one year). PM2.5 emissions will create significant impacts during months identified above.

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 violation 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 90 months (7.5 years). The direct impacts of CO and SO_2 would not be significant because construction of the project would neither cause nor contribute to a violation of these standards.

Construction Mitigation

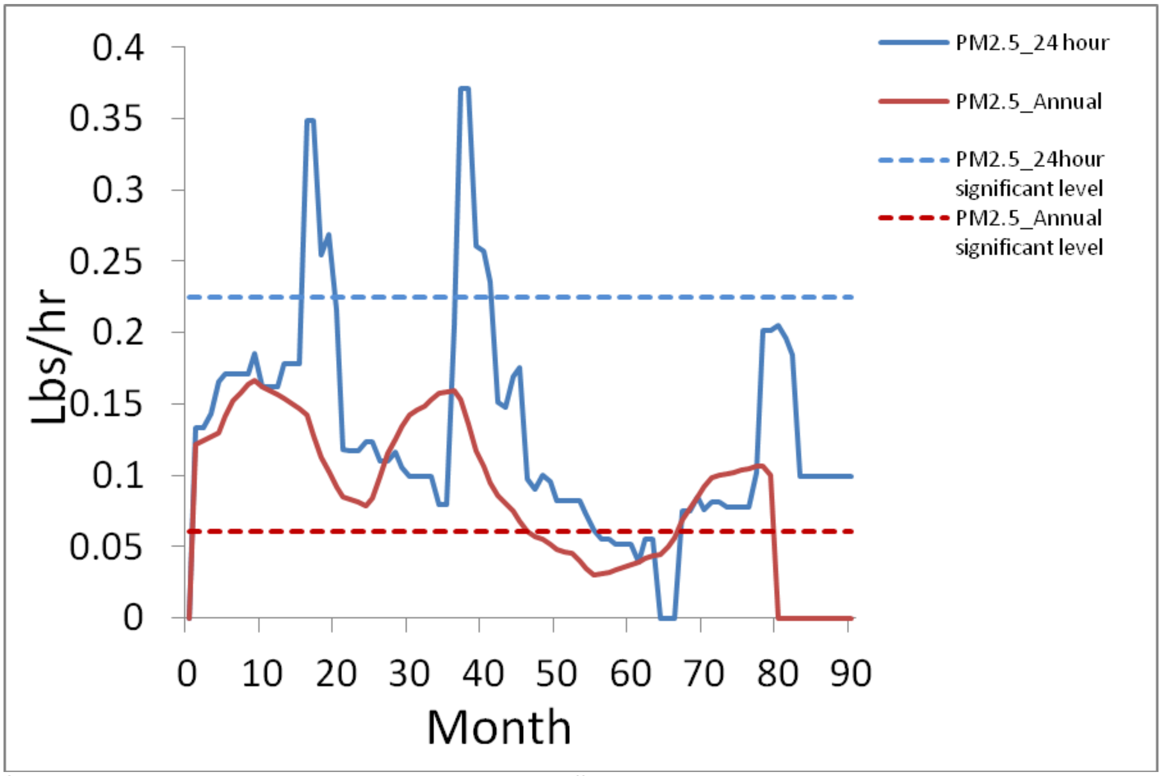
The applicant proposes the following mitigation measures to reduce the exhaust emissions from the diesel heavy equipment and fugitive dust emissions during the construction of the project:

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



Source: Table 5.1A 46R, HBEP 2014a, 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.

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



Source: Table 5.1A 46R, HBEP 2014a, 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.

- 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 two weeks Using ultra-low sulfur diesel fuel (15 ppm sulfur) in all diesel-fueled equipment
- Use of Tier III 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.

AIR QUALITY Table 13
HBEP, Modeled Project Construction Impacts Revisions (μg/m³)

Pollutant	Averaging Time	Modeled Impact[a] (06/2012)	Modeled Impact[b] (03/2013)	Modeled Impact[c] (11//2013)	Modeled Impact[d,e] (01/2014)
PM10	24 hour	333	218	72.8	35.8
	Annual	121	34.8	14.6	9.75
PM2.5	24 hour	84.0	48.2	15.5	11.0
	Annual	31.1	11.0	3.72	2.71
CO	1 hour	2,289	85.9	112	112
	8 hour	1,404	76.2	93.2	93.2
NO_2	State 1 hour	591	69.5	91.7	91.7
	Federal 1 hour	591	69.5	183	183
	Annual	155	6.71	7.33	7.33
SO_2	State 1 hour	4.74	0.16	0.22	0.22
	Federal 1 hour	4.74	0.16	0.22	0.22
	24 hour	0.836	0.04	0.04	0.04

Notes: HBEP 2012a –Values shown in the original AFC
HBEP 2013o –Values revised due to improved emissions controls
HBEP 2013kk—Values further revised using updated meteorology data and additional emissions controls.
HBEP 2014a—Values once again revised using new meteorology data (HBEP 2013kk), improved emissions controls and updated emissions factors
Values used in Air Quality Table 12

Adequacy of Proposed Mitigation

Staff generally concurs with the applicant’s proposed mitigation measures, which mirror many of the staff’s mitigation recommendations from previous siting cases. But staff has been proposing additional fugitive dust mitigation, such as requiring the use of soil binders or paving to reduce emissions on unpaved roads, considered necessary to reduce the high fugitive dust emission potential during construction. Staff incorporates off-road equipment mitigation measures beyond those proposed by the applicant to fully implement current staff recommendations.

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 mitigation. Construction emissions and the effectiveness of mitigation varies widely depending on variable levels of activity, the specific work taking place, the specific equipment, soil conditions, weather conditions, and other factors, making 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 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 beginning construction; the applicant should provide an Air Quality Construction Mitigation Plan (AQCMP) that specifically identifies mitigation measures to limit air quality impacts during construction.

Staff includes Conditions of Certification **AQ-SC1** through **AQ-SC5** to implement these requirements. These conditions update the applicant’s proposed mitigation to be consistent with the conditions of certification adopted in similar prior licensing cases. Compliance with these conditions is expected to reduce the potential for adverse air quality impacts during construction of the HBEP. However, the latest modeling still shows that PM10 and PM2.5 impacts during the approximately 7.5-year project construction period would cause extensive exceedances of health-based ambient air quality standards and thus these impacts would be significant. Staff recommends that the applicant continue to refine the modeling, and consider staggering construction activities and employ additional mitigation measures to further reduced emissions and potential impacts.

Additional control measures proposed by the applicant would have to be described (e.g., location) and quantified (e.g., lbs/day reduction or control efficiency). Construction emission reduction measures could 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 measure that can provide local emission reductions coincident with construction emissions.

Operation Impacts and Mitigation

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

Routine Operation Impacts

A refined dispersion modeling analysis was performed by the applicant to identify off-site criteria pollutant impacts that would occur from routine operational emissions throughout the life of the project. The worst case 1-hour NO_2 and CO impacts reflect startup impacts, and all other impacts reflect impacts during normal operation. The modeled impacts are extremely conservative, since the maximum impacts are evaluated under a combination of highest allowable emission rates and the most extreme meteorological conditions, which are unlikely to 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 14**. The values shown in bold means they exceed ambient air quality standards.

AIR QUALITY Table 14
HBEP, Routine Operation Maximum Impacts (µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	4.7	45	49.7	50	99
	Annual	**0.27**	**24.2**	**24.47**	**20**	**122**
PM2.5	24 hour[a]	4.7	28.3	33.0	35	94
	Annual	0.27	11.0	11.27	12	94
CO	1 hour	333	3,450	3,783	23,000	16
	8 hour	78	2,444	2,522	10,000	25
NO_2 [b]	State 1 hour	58.8	139	197.8	339	58
	Federal 1 hour[c]	58.8	105	163.8	188	87
	Annual	0.5	21	21.5	57	38
SO_2	State 1 hour	7.1	26	33.1	655	5
	Federal 1 hour[d]	7.1	13	20.1	196	10
	24 hour	2.4	5	7.4	105	7

Source: HBEP 2013kk with independent staff analysis.
Note:
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.
The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
Total predicted concentration for the federal 1-hour NO_2 standard is the maximum modeled concentration combined with the 3-year average of 98th percentile background concentrations.
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 14 shows that the project will not cause a significant impact except annual PM10 emissions, which will contribute to existing violations of annual PM10 ambient air quality standards. The impacts of PM2.5 and 24 hour PM10 are close to the most stringent standards due to the existing high background concentrations but would not create new violations. The 24 hour PM10 concentration exceeds the CEQA significant increase level of 2.5 $\mu g/m^3$ defined by SCAQMD's CEQA guidance. The significant increase level is defined in district Rule 1303 Table A-2. However, as an Energy Commission jurisdictional project using district Rule 1304, HBEP is 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. Therefore, staff believes that HBEP would not have a significant 24-hour PM10 impact.

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 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, NO_2, and ozone.

Secondary Pollutant Impacts

The project's gaseous emissions of NOx, SOx, VOC, and ammonia 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 ozone and of NOx, SOx, and ammonia emissions to secondary PM10 and PM2.5 formation, 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 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 reported maximum pollutant emission rates for the MPSA 501DA (HBEP 2012a), staff recommends an ammonia slip limit of 5 ppmvd at 15% oxygen.

Commissioning-Phase Impacts

Commissioning impacts would occur over a short-term period needed to complete the commissioning. The commissioning of each of the two HBEP power blocks is expected to be completed within 180 calendar days. 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**.

Since the commission periods for Block 1 and Block 2 will not occur within the same year, it is assumed that the maximum predicted impacts for the simultaneous commissioning of all three units at Block 2 combined with the cold startup of all three units at Block 1 would be greater than the predicted impacts from the commissioning or cold startup of Block 1 only. It was also assumed that the maximum impact would occur if all three turbines were simultaneously undergoing commissioning activities with the highest unabated emissions. Therefore, the modeling of short term NO_2, CO impacts are based on the simultaneous commissioning of all three units at Block 2 combined with the cold startup of all three units at Block 1. 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 evaluated 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. The annual NO_2 impact is not evaluated either due to the short commissioning period. 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, the SO2, PM10, and PM2.5 impacts from the commissioning are the same as those from normal operation shown in **Air Quality Table 14**.

Air Quality Table 15 shows that the commissioning-phase emissions will not cause new exceedances of any state or federal air quality standard.

AIR QUALITY Table 15
HBEP, Commissioning-Phase Maximum Impacts (µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
CO	1 hour	5,076	3,450	8,526	23,000	37
	8 hour	4,369	2,444	6,813	10,000	68
NO_2	1 hour (state)	146.3	139	285.3	339	84

Source: SCAQMD 2014a with independent staff analysis.

Mitigation for Routine Operation

Applicant's Proposed Mitigation

The 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

HBEP proposes the use of dry low NOx combustors with SCR to control NOx to 2.0 ppmvd (1-hour average) with and without duct burning. The BACT for CO emissions is best combustion design and the installation of the oxidation catalyst system to reduce CO to 2.0 ppmvd (1-hour) with and without duct burning. 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) with and without duct burning. Best combustion practice, use of pipeline-quality natural gas, and use inlet air filtration limit PM10/PM2.5 emissions to 4.5 lb/hr without duct burning and 9.5 lb/hr with duct burning. Operating exclusively on low sulfur pipeline quality natural gas with fuel sulfur content of no more than one grain per 100 standard cubic feet limits SO_2 emissions. Generally the actual sulfur content is about 0.25 grains per 100 standard cubic feet of fuel.

GHG pollutants are emitted during the combustion process when fossil fuels are burned. The applicant conducted the top-down GHG BACT analysis and determined that thermal efficiency is the only technically feasible control technology that is commercially available and applicable for the HEBP. The HBEP has concluded that the BACT for GHG emissions is an emission rate of 1,054 pounds CO_2/MWhr of gross energy output. Degradation over time and turndowns, startup, and shutdown are incorporated into these limits. See **Air Quality Appendix Air**-1 for more discussion of greenhouse gases.

Emission Offsets

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

District Rule 1304(a)(2) –Electric Utility Steam Boiler Replacement states that if the electric utility boilers are replaced by advanced gas turbines, including combined cycle and simple cycle configurations,[1]the project would be exempt from emission offset requirements 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. SCAQMD Rule 1135 defines advance combustion sources as those which emit NOx at no greater than 0.10 lb/net MWh on a daily average basis, excluding commissioning, start-up and shutdown periods, if the source is located within the South Coast Air Basin. The MPSA 501DA gas turbine is a combined cycle gas turbine and complies with this rule.

[1] The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules.

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 PDOC shows the total power generating capacity from the proposed six MPSA 501DA turbines would be 972 MW gross and 939 MW net. Maximum capacity is determined at 32°F ambient temperature. The plant output would be limited by Conditions of Certification AQ-14 and AQ-15. In order to qualify for the exemption, the applicant is proposing to shutdown 4 boilers in conjunction with the construction of the new HBEP. The 4 boilers include Boilers 1 (215 MW) and 2 (215 MW) at the Huntington Beach site, as well as Boilers 6 (175 MW) and 8 (480 MW) at the AES' Redondo Beach Generating Facility. The total capacity of the boilers being shutdown is 1,085 MWs. Therefore the net megawatts would decrease and the new power generating system would qualify for the Rule 1304(a)(2) exemption. The facility does not have to provide emission reduction credits for VOC and PM10 emissions of the new gas turbines. Instead, the VOC and PM10 emissions of the new gas turbines would be fully offset from SCAQMD's internal bank.

District 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. HBEP would be required to demonstrate compliance with the specific requirements of this rule prior to issuance of the Permits to Construct for the proposed facility.

Under Rule 2005, the HBEP would be subject to the Regional Clean Air Incentives Market (RECLAIM) program for NOx emissions. The facility would be required to demonstrate that it holds sufficient RECLAIM Trading Credits (RTCs) to offset the annual NOx emission increase for the first compliance period using a 1-to-1 offset ratio. Additionally, since the NOx potential to emit (PTE) after the commissioning year is greater than the facility's initially allocation, HBEP is required to hold NOx RTCs for each subsequent year. The HBEP 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.

Air Quality Table 16 shows the California Environmental Quality Act (CEQA) mitigation that is provided for the emission impacts from the proposed project, which is based on the new source review (NSR) offsets/emissions identified in the SCAQMD PDOC (SCAQMD 2014a) and staff's own analysis. Values shown in parentheses indicate emissions for routine operation while those without parentheses apply to the commissioning period.

The emissions shown in **Air Quality Table 16** 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.

AIR QUALITY Table 16[b]
CEQA Mitigation (30-day average lbs/day)

	NOx (lbs/year)[a]	VOC	PM10	SOx (lbs/year)[a]
Emission Reduction Credits or RECLAIM Trading Credits	117,750 (501,972)	0	0	28,398 (80,346)
1304 Exemption Credits	0	1,497.6	855.6	0
Total Credits	117,750 (501,972)	1,497.6	855.6	28,398 (80,346)
CEQA Mitigation Needed	117,750 (501,972)	1,497.6	855.6	28,398 (80,346)
Further Mitigation Needed	None	None	None	None

Source: SCAQMD 2014a and independent staff analysis
Note:
[a] NOx and SOx emissions for the commissioning year would be lower than non-commissioning years. All NOx and SOx emissions for both commissioning year and non-commissioning years (shown in parentheses) would be offset by RTCs.
[b] Values are subject to refinement in FDOC and FSA.

District 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. HBEP is not a major PM2.5 facility because the total PM2.5 potential to emit of the facility would be 99.3 tons per year, which is less than the 100 tons per year threshold. Therefore, no PM2.5 offsets are required for HBEP.

Because the facility area is classified as attainment for CO, the district 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 proposed facility does not cause or contribute to a violation of a CO ambient air quality standard.

Adequacy of Proposed Mitigation

Staff believes that 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.

Commission staff have 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 HBEP, the district would provide emission offsets from its internal bank that would meet or exceed a one-to-one offset ratio for all ozone and particulate matter precursors. Staff concludes that adverse impacts are mitigated for CEQA purposes by these emissions reductions. These offsets are required before beginning construction. Although PM2.5 emissions are not required to be offset separately from PM10 emissions, staff notes that the annual total offsets for PM10 would fully offset PM2.5 emissions. How the offsets provide PM2.5 mitigation is discussed separately in **Secondary Pollutant Impacts** (above).

Energy Commission staff's position for CEQA mitigation in this region is that all nonattainment pollutant and precursor emissions must be reduced by a ratio of at least one-to-one. 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 at a minimum ratio of 1:1 will reduce secondary PM10/PM2.5 impacts to less than significant for the proposed facility modifications.

As shown in **Air Quality Table 16**, there are sufficient mitigation credits to fully offset the new emissions that would be expected to occur at the site from the new HBEP.

Staff's evaluation of the adequacy of project mitigation was determined solely based on the merits of this case, including the district 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 Conditions of Certification **AQ-SC6** 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-SC7**).

Overlap Periods Impacts and Mitigation

Due to the 8-year construction period, some construction activities would overlap with the operation of HBEP units. Therefore staff identified the overlappg periods and request the applicant to conduct impact analyses for all scenarios identified by staff. In addition, since the demolition of exsiting HBEP Units 3 and 4 is not part of the proposed project, its impact was not evaluated in the AFC. But the timing for demolition of Units 3 and 4 would also overlap some HBEP project activities. Therefore staff also requested the impact analysis for the overlap of Units 3 and 4 demolition with HBEP project activities and require evaluation. These overlapping activities are all evaluated below. 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 resutls for these standards are exremely conservative.

A. Block 1 Operation and Construction of Block 2

This scenario is intended to determine modeled impacts from the simultaneous operation of Block 1 and construction of Block 2 (3rd quarter, 2018 to 2nd quarter, 2020). The maximum modeled concentrations for this scenario are presented in **Air Quality Table 17.**

AIR QUALITY Table 17
Maximum Impacts from Block 1 Operation and Construction of Block 2 (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	**18.9**	**45**	**63.9**	**50**	**128**
	Annual	**5.96**	**24.2**	**30.16**	**20**	**151**
PM2.5	24 hour[a]	2.08	28.3	30.38	35	87
	Annual	0.79	11.0	11.79	12	98
CO	1 hour	97.9	3,450	3,547.9	23,000	15
	8 hour	53.8	2,444	2,497.8	10,000	25
NO_2 [b]	State 1 hour	63.0	139	202	339	60
	Federal 1 hour[c]	63.0	105	168	188	90
	Annual	3.38	21	24.38	57	43
SO_2	State 1 hour	1.32	26	27.32	655	4
	Federal 1 hour[d]	1.32	13	14.32	196	7
	24 hour	0.36	5	5.36	105	5

Source: HBEP 2013kk with independent staff analysis.
[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 maximum modeled concentration combined with the 3-year average of 98th percentile 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.

Staff believes that PM10 emissions during this overlap period (up to 12 months) would cause a significant impact because they would cause a new violation of the 24 hour PM10 standard which is not expected to occur during routine operation (see **Air Quality Table 14**) 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-SC5** are expected to reduce the potential for significant adverse air quality impacts as much as possible during construction. 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. HBEP Operation and Demolition of Units 1 and 2

This scenario is intended to determine modeled impacts from the simultaneous operation of HBEP units (block 1 and block 2) and demolition of Huntington Beach Generating Station Units 1 and 2 (4th quarter, 2020 to 3rd quarter, 2022). The maximum modeled concentrations for this scenario are presented in **Air Quality Table 18.**

Staff believes that particulate matter emissions during this overlap period (up to 12 months) would cause a significant impact because they would cause new violations or contribute to existing violations of PM10 and PM2.5 ambient air quality standards, and additionally that those emissions can and should be mitigated to a level of insignificance. These impacts are greater than the values shown in **Air Quality Table 17**. Significant secondary impacts would also occur for PM10, PM2.5, and ozone because emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would also contribute to existing violations of these standards. The mitigations included in Conditions of Certification **AQ-SC1** through **AQ-SC5** are expected to reduce the potential for significant adverse air quality impacts during the construction. 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.

C. HBEP Construction and Demolition of Units 3 and 4

This scenatio is intended to determine modeled impacts from the simultaneous demolition of Units 3 and 4 and development (contruction and demolition) of HBEP. The overlap period starts from the 2nd quarter of 2015. However, the end date is unknown to staff because the demolition of Units 3 and 4 is not a part of HBEP project and the schedule is not reported. The maximum modeled concentrations for this scenario are presented in **Air Quality Table 19.**

Staff believes that PM10 emissions during this overlap period would cause a significant impact because they would cause a new violation of 24-hour PM10 standard and would contribute to the existing violation of annual PM10 standard. Significant secondary impacts would also occur for PM10, PM2.5, and ozone because emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would also create new exceedances or contribute to existing violations of these standards.

AIR QUALITY Table 18
Maximum Impacts from HBEP Operation and Demolition of Units 1 and 2 ($\mu g/m^3$)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	**36.1**	**45**	**81.1**	**50**	**162**
	Annual	**6.13**	**24.2**	**30.33**	**20**	**152**
PM2.5	24 hour[a]	**8.02**	**28.3**	**36.32**	**35**	**104**
	Annual	**1.09**	**11.0**	**12.09**	**12**	**101**
CO	1 hour	338	3,450	3,788	23,000	16
	8 hour	106	2,444	2,550	10,000	26
NO_2 [b]	State 1 hour	82.5	139	221.5	339	65
	Federal 1 hour[c]	-	-	174	188	93
	Annual	4.59	21	25.59	57	45
SO_2	State 1 hour	4.97	26	30.97	655	5
	Federal 1 hour[d]	4.97	13	17.97	196	9
	24 hour	1.23	5	6.23	105	6

Source: HBEP 2014a with independent staff analysis.
[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 maximum modeled concentration paired with the 3-year average of 98th percentile seasonal hourly 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.

The direct impacts of NO_2 would also create a new violation of the new Federal 1-hour NO_2 standard. However, staff does not expect it to have significant impact due to the limited overlap period compared to the 3-year averaging time used for the standard. The direct impacts of PM2.5, CO and SO_2 would not be significant because they would neither cause nor contribute to a violation of these standards.

AIR QUALITY Table 19
Maximum Impacts from HBEP Construction and Demolition of Units 3 and 4
(µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	**42.6**	**45**	**87.6**	**50**	**175**
	Annual	**13.8**	**24.2**	**38**	**20**	**190**
PM2.5	24 hour[a]	12.9	28.3	41.2	35	**118**
	Annual	2.72	11.0	13.72	12	**114**
CO	1 hour	131	3,450	3,581	23,000	16
	8 hour	110	2,444	2,554	10,000	26
NO_2 [b]	State 1 hour	117	139	256	339	76
	Federal 1 hour[c]	**-**	**-**	**196**	**188**	**104**
	Annual	7.14	21	28.14	57	49
SO_2	State 1 hour	0.29	26	26.29	655	4
	Federal 1 hour[d]	0.29	13	13.29	196	7
	24 hour	0.054	5	5.054	105	5

Source: HBEP 2014a with independent staff analysis.
[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 maximum modeled concentration paired with the 3-year average of 98th percentile seasonal hourly 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.

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" direct emissions locally when combined with other local major emission sources; and
- a discussion of greenhouse gas emissions and global climate change impacts (see **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/aqmp/2012aqmp/index.htm
- **Final 2007 Air Quality Management Plan** (adopted 06/01/2007)
  Link: http://www.aqmd.gov/aqmp/07aqmp/index.html
- **Final Socioeconomic Report for the Final 2012 AQMP** (adopted 12/07/2012)
  Link: http://www.aqmd.gov/aqmp/2012aqmp/Final/FinalSocioeconomicReport.pdf
- **State of California's SIP for the new federal PM2.5 and 8-hour ozone standards** (adopted June 20, 2011)
  Link: http://www.arb.ca.gov/planning/sip/2007sip/2007sip.htm

2012 Air Quality Management Plan

(The following paragraphs are excerpts 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 an 24-hour PM2.5 non-attainment area to prepare a State Implementation Plan (SIP) revision 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 CARB and 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:

1) 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.

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

3) 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.

4) 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 excerpts 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 State Implementation Plan (SIP) revision by June of 2007 (which has been completed) and a PM2.5 non-attainment area to submit a SIP revision by late 2007 (which has been completed). 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 (CARB) and the Southern California Association of Governments (SCAG) reflecting their upcoming model (EMFAC) for motor vehicle emissions and demographic updates.

The AQMP relies on a comprehensive and integrated control approach to achieve the PM2.5 standard by 2015 through implementation of short-term and midterm control measures and achieve the 8-hour ozone standard by 2021/2024 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 2020/2023 timeframe.

The AQMP control measures consist of four components: 1) the District's Stationary and Mobile Source Control Measures; 2) CARB's Proposed State Strategy; 3) District Staff's Proposed Policy Options to Supplement VARB'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 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 CARB 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., 72% of SOx and 34% of NOx), 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 excerpts from the Final Socioeconomic Report for the Final 2012 AQMP adopted by the SCAQMD December, 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 (CARB). 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 June 20, 2011)

On April 28, 2011, the Air Resources Board 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. 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 proposed project 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. HBEP requested that the SCAQMD identify potential new stationary sources within six miles of the HBEP site. The SCAQMD provided emission inventory and the list of new projects near the HBEP. Based on the detailed permit application data received from SCAQMD, additional facilities were removed from the cumulative assessment if the applications were adinistrative changes only, the permitted sources did not result in an increase in emissions, the emissions increase were less than significatnt (less than a 5 ton increase), or the location of the permitted source was beyond 6 miles from HBEP. In addition to the HBEP, there are three sources included in the cumulative analysis:

- Orange County Sanitation District (Facility ID 17301) located in Fountain Valley, CA with five emission sources;
- Orange County Sanitation District (Facility ID 29110) located in Huntington Beach, CA with seven emission sources;
- Arion Graphics, LLC (Facility ID 167066) containg one recuperative thermal oxidizer (RTO)

The maximum modeled cumulative impacts are presented below in **Air Quality Table 20**. The total impact is conservatively estimated by the maximum modeled impact plus existing maximum background pollutant levels.

Air Quality Table 20 shows that HBEP, along with three other existing sources, would not cause new violations for PM2.5, CO, NO_2, and SO_2. However, PM10 emissions from HBEP would be cumulatively considerable because they would contribute to the existing violations of annual PM10 ambient air quality standards. The HBEP would mitigate emissions through the use of district required best available control technology (BACT) and staff recommended banked or new, owner-funded, emission reductions. Therefore, the cumulative operating impacts after mitigation are considered to be less than significant.

AIR QUALITY Table 20
HBEP, Ambient Air Quality Impacts from Cumulative Sources (µg/m³)

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	4.73	45	49.73	50	99
	Annual	**0.28**	**24.2**	**24.48**	**20**	**122**
PM2.5	24 hour[a]	4.73	28.3	33.03	35	94
	Annual	0.28	11.0	11.28	12	94
CO	1 hour	328	3,450	3,778	23,000	16
	8 hour	78.4	2,444	2,522.4	10,000	25
NO_2 [b]	State 1 hour	58.6	139	197.6	339	58
	Federal 1 hour[c]			148	188	79
	Annual	0.73	21	21.73	57	38
SO_2	State 1 hour	4.95	26	30.95	655	5
	Federal 1 hour[d]	4.95	13	17.95	196	9
	24 hour	1.22	5	6.22	105	6

Source: HBEP 2013kk with independent staff analysis.
[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 maximum modeled concentration paired with the 3-year average of 98th percentile seasonal hourly 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.

Since HBEP is subject to prevention of significant deterioration (PSD) review for NO_2 and CO, 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 PM, SO_2, CO, and annual NO_2 impacts from the new units shown in **Air Quality Table 14** are all below corresponding SILs levels. However, the maximum 1-hour NO_2 impacts would exceed the applicable NO_2 SIL (7.5 µg/m³), so an increments analysis is required for NO_2 impacts. The SCAQMD and EPA identified three sources to include in the 1-hour NO_2 cumulative analysis:

- Orange County Sanitation District (Facility ID 17301) located in Fountain Valley, CA with five emission sources;

- Orange County Sanitation District (Facility ID 29110) located in Huntington Beach, CA with seven emission sources;
- Beta Offshore (Facility ID 166903): located in Huntington Beach, CA with 21 emisson sources

In addition to the above facilities, emissions from shipping lane activities off the California coast are also included in the 1-hour NO_2 cumulative assessment. **Air Quality Table 21** shows the maximum 1-hour NO2 impact from these cumulative sources. As shown in **Air Quality Table 21,** HBEP cumulative sources would not cause new violations for federal 1-hour NO_2 standard. Therefore, no additional PSD analysis is necessary.

The project's peak 24-hour impact is 4.7 ug/m3, which is less than the Class II SIL of 5 ug/m3, therefore no additional PSD analysis is necessary.

AIR QUALITY Table 21
Maximum 1-hour NO_2 Impacts from Cumulative Sources ($\mu g/m^3$)

Pollutant	Averaging Time	Total Impact[a]	Limiting Standard	Percent of Standard
NO_2	1 hour (federal)	168.2	188	89

Source: SCAQMD 2014a.
Note:
[a]Total predicted concentration for the federal 1-hour NO_2 standard is the maximum modeled concentration paried with the 3-year average of 98[th] percentile seasonal hour-of-day background concentrations.

COMPLIANCE WITH LORS

The Preliminary Determination of Compliance (PDOC) for HBEP was released and dated January 24, 2014 (SCAQMD 2014a). Compliance with all district Rules and Regulations was demonstrated to the district's satisfaction in the PDOC, and the PDOC conditions are presented in the Conditions of Certification located near the end of this section.

FEDERAL

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

40 CFR 52, Prevention of Significant Deterioration. The HBEP project is subject to permit requirements under the Prevention of Significant Deterioration (PSD) program. The facility owner submitted the PSD application to the district on June 26, 2012.

40 CFR 60 Subpart Da, NSPS for Steam Generators. The fired HRSGs are subject to this subpart because their heat input rating is 507 mmbtu/hr which is greater than the applicability standard of 250 mmbtu/hr in the rule. The emission standards that apply are: NOx 0.2 lbs/mmbtu, PM 0.015 lbs/mmbtu, SO_2 0.2 lbs/mmbtu. Anticipated emissions from the gas turbines/duct burners are: NOx 0.0081 lbs/mmbtu, PM 0.0050 lbs/mmbtu, SO_2 0.0015 lbs/mmbtu. The emissions estimates are all lower than subpart Da requirements. Compliance is expected.

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 (10 MMBtu per hour) at peak load, based on the higher heating value of the fuel fired. Actual unit rating is 1498E+06 btu/hr (HHV) X 1055 joules/btu = 1580.4 gigajoules/hr. The standards applicable for a natural gas turbine greater than 850 mmbtu/hr are: NOx 15 ppm at 15% O_2 (0.43 lbs/MWh), SOx: 0.90 lbs/MWh discharge, or 0.060 lbs/mmbtu potential SO2 in the fuel. 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/100cf (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% of 100% 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% of the major source thresholds on a pre-control basis. The HBEP is a major source and the turbine emissions are greater than the major source thresholds for NOx, CO, VOC, and PM10, and the turbines will be subject to an emission limit for each of these pollutants. Control systems are used for NOx, CO, and VOC, but not PM10.

NOx is subject to a 2.0 ppm one hour BACT limit and is controlled with the SCR. 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 under 64.2(b)(vi).

CO is subject to a 2.0 ppm one hour BACT limit and is controlled with the oxidation catalyst. The turbines will be required to use a CO CEMS under Rule 218. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

VOC is subject to a 2.0 ppm one hour BACT limit and is controlled with the oxidation catalyst. The oxidation catalyst is effective at operating temperatures above 500°F. The facility is required to maintain a temperature gauge in the exhaust, 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 500°F, (with exceptions for start ups and shutdowns). This will insure that the oxidation catalyst is operating properly. Compliance is expected.

40 CFR Part 72, Acid Rain Provisions. The HBEP will be subject to the requirements of the federal acid rain program, because the turbines are utility units 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 HBEP was given initial allowance allocations based on the past operation of their boilers. AES can either use those allocations, or if insufficient, must purchase additional allocations to cover the operation of the new turbines. The applicant 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 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

HBEP has demonstrated that the project 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 preliminary determination of compliance (PDOC, SCAQMD 2014a) and the Energy Commission staff's Conditions of Certification enable staff's affirmative finding.

LOCAL

The applicant provided an air quality permit application to the SCAQMD and the district has issued a PDOC (SCAQMD 2014a), which states that the proposed project is expected to comply with all applicable district rules and regulations. The SCAQMD will also issue a final determination of compliance (FDOC) after considering comments submitted during the comment period~~.~~

The district rules and regulations specify the emissions control and offset requirements for new sources such as the HBEP. Best Available Control Technology would be implemented, and RECLAIM trading credits (RTCs) for NOx and SOx emissions are required by district rules and regulations based on the permitted emission levels for this project. Compliance with the district's new source requirements would ensure that the project would be consistent with the strategies and future emissions anticipated under the district'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 applicant for the HBEP, the district 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 proposed project would comply with the district's applicable rules and regulations, as described below.

Compliance with specific SCAQMD rules and regulations is discussed below via excerpts from the PDOC (SCAQMD 2014a). For a more detailed discussion of the compliance of the proposed facility modifications, please refer to the PDOC (SCAQMD 2014a).

Regulation II – Permits

RULE 212 – Standards for Approving Permits. This project is subject to Rule 212 public notice requirements because the daily maximum VOC, CO, NOx, and PM10 emissions from the project will all exceed the emissions thresholds specified in subdivision (g) of this rule. The District will prepare the public notice and it will contain sufficient information to fully describe the project. In accordance with subdivision (d) of this rule, the applicant 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 insure 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 AQMD. Any CEMS breakdowns must also be reported. Compliance with this rule is expected.

Regulation IV – Prohibitions

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

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 and ammonia tank 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 applicant will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. In addition, the applicant 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 407 – Liquid and Gaseous Air Contaminants. This rule limits CO emissions to 2000 ppmv. The CO emissions from the turbines will be controlled by an oxidation catalyst to 2.0 ppmvd at 15% 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% CO_2, averaged over 15 minutes. The turbines have a grain loading of 0.003 grains/scf at the maximum firing load and therefore are expected to meet this limit. Compliance will be verified through the initial performance test.

RULE 431.1 – Sulfur Content of Gaseous Fuels. The natural gas supplied to the turbines 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 turbines 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 turbines are based on 12 ppm or about 0.75 gr/100 cf. The applicant 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 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 turbine are estimated at 9.5 lbs/hr, and 0.0033 gr/scf during natural gas firing at maximum firing load. Therefore, compliance is expected. Compliance will be verified through the initial performance test as well as ongoing periodic testing.

REGULATION XIII – New Source Review. The new turbines are subject to NSR, including BACT, modeling, and offsets. Also, the addition of the turbines to the 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. For major sources, BACT is determined at the time the permit is issued, SCAQMD has determined that BACT for combined cycle gas turbines is: NOx 2.0 ppmdv @ 15% O_2, one hour average, CO 2.0 ppmdv @ 15% O_2, one hour average, VOC 2.0 ppmdv @ 15% O_2, one hour average, PM10 Natural gas fuel, SOx Natural gas fuel with fuel sulfur content of no more than 1 grain/100 scf (about 16 ppm), NH_3 5.0 ppmdv @ 15% O_2, one hour average. Compliance is verified in the DOC.

Modeling

The applicant performed dispersion modeling for NO_2, CO, SO_2, and PM. Modeling evaluations were performed using the American Meteorological Society/USEPA AERMOD (version 12345) model and representative meteorological data from the John Wayne Airport meteorological station. Modeling analysis was performed for turbine startups, normal turbine operation, and turbine commissioning operations.

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

Offsets

The applicant is requesting that the project 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) or several other clearer generation technologies, and allows an exemption from modeling and offsets for non-RECLAIM pollutants 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 exemption, the applicant is proposing to shutdown four boilers in conjunction with the construction of the new HBEP. Those four boilers include Boilers 1 and 2 at the Huntington Beach site, as well as Boilers 6 and 8 at AES' Redondo Beach Generating Facility. The total capacity of the boilers being shutdown is 1,085 MWs. The capacity of the new units is 939 MWs net. The plant would be limited to this output by Condition of Certification AQ-14.

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 PTE after the commissioning year is greater than the facility's initial allocation, the facility is required to hold NOx RTCs for each subsequent year. 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 either Zone 1 or Zone 2A.

Facility Compliance. This facility is currently in compliance with all applicable rules and regulations of the District.

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 to 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 PM_{10} 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 applicant 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 project 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 the issuance of the Permits to Construct for the HBEP.

RULE 1325 – Federal PM2.5 New Source Review. This rule applies to major polluting facilities, which have actual emissions, or a potential to emit of greater than 100 tons per year. A major polluting facility is required to comply with the following requirements: 1) use lowest achievable emissions rate (LAER), 2) offset PM2.5 emissions at the offset ratio of 1.1:1, 3) certify compliance with emission limits and 4) conduct an alternative analysis of the project. The total PM2.5 potential to emit resulting from the addition of the 6 turbines will not result in an emissions increase above the 100 ton/year threshold. Therefore, the 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 for this project.

The applicant performed modeling which indicated that the maximum 1-hour and 8-hour CO impacts from turbine operations are below the corresponding US EPA CO Class II SILs. Therefore, 1-hour and 8-hour CO increment analyses are not required. The peak annual NO_2 impact from the total project is less than the US EPA NO_2 Class II significance impact of level, therefore, no additional PSD analysis is necessary.

For 1-hour NO_2 impacts, it was first determined that the peak impact level from the proposed project exceeds the significance impact level of 7.52 ug/m3. Therefore, a cumulative impact assessment is necessary. For the cumulative impact assessment, three facilities, Orange County Sanitation District's Huntington Beach and Fountain Valley facilities and 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. Following the form of the standard, the 1-hour NO_2 impact from the project plus cumulative sources plus background is 168.2 ug/m^3, which is less than the Federal 1-hour standard of 188 ug/m^3. Therefore, no additional PSD analysis is necessary.

Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the 24 hour PM10 NAAQS. The project's total peak 24-hour impact is 4.74 ug/m^3, which is less than the Class II significant impact level (SIL) of 5 ug/m^3, therefore no additional PSD analysis is necessary.

Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

Rule 2011 – SOx RECLAIM, Monitoring Recording and Recordkeeping Requirements. The turbines 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 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 Emissions Monitoring System (CEMS). The CEMS would include in-stack NOx and O2 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, and is operating under a valid Title V permit issued on May 4, 2011. The addition of the combined cycle plant would be considered a significant revision to the existing Title V permit. AES has submitted a Title V revision application A/N 540259. As a significant revision, the permit is subject to a 30 day public notice and a 45 day EPA review and comment period.

PROPOSED FINDINGS

Based on the staff's analysis, we recommend the following findings:

1. The HBEP would be located in the South Coast Air Basin and within the South Coast Air Quality Management District.

2. The area where HBEP would be located is designated as nonattainment for both state and federal ozone and PM2.5 standards, attainment for federal PM10 and nonattainment for state PM10 standards, and attainment for both state and federal CO, NO_2 and SO_2 standards.

3. The project construction impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff recommends Conditions of Certification **AQ-SC1** to **AQ-SC5** to mitigate the construction-phase impacts of the proposed project. However, the construction PM10 and PM2.5 impacts are still significant. Staff recommends that the applicant continue to refine the modeling, consider staggering construction activities, and implementing additional mitigation measures to reduce emissions and potential impacts.

4. The project operation would neither cause new violations of CO, NO_2, SO_2 and PM2.5 ambient air quality standards nor contribute to existing violations for these pollutants. Therefore, the project's direct CO, NO_2, SO_2 and PM2.5 impacts are less than significant.

5. The project's NOx and VOC emissions would contribute to existing violations of state and federal ozone ambient air quality standards. The RECLAIM Trading Credits (RTCs) and volatile organic compound (VOC) offsets from the district's internal bank would mitigate the ozone impact to a less than significant level.

6. The project's annual PM10 emissions would contribute to the existing violation of state air quality standards. The District would offset the PM10 emissions from its internal bank to mitigate the PM10 impacts of the new gas turbines to a less than significant level. The offsets would be in sufficient quantities to satisfy Energy Commission staff's recommendation that all nonattainment pollutant and precursor emissions be offset by at least a one pound of offsets for each pound of emissions.

7. The SCAQMD has issued a PDOC finding that HBEP would comply with all applicable district rules and regulations for project operation. The district's PDOC conditions are included herein as conditions of certification **AQ-1** through **AQ-39**.

8. This analysis contains an adequate evaluation of the project's contributions to cumulative air quality impacts.

9. Implementation of the conditions of certification listed below would ensure that the HBEP will not result in any significant direct, indirect, or cumulative adverse impacts to air quality.

PROPOSED CONCLUSIONS

Staff recommends the following conclusions about the HBEP:

- Construction impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff recommends conditions of certification **AQ-SC1** to **AQ-SC5** to mitigate the project's construction-phase impacts. Due to the long construction period (90 months) and the complexity of construction activities, compliance with these conditions would be critical to reduce construction impacts. However, the construction PM10 and PM2.5 impacts are still significant after the implementation of proposed mitigation measures.
- Operation of the project would comply with applicable SCAQMD rules and regulations, including New Source Review, Best Available Control Technology (BACT) requirements, and requirements to offset emission increases; staff recommends the inclusion of the District's PDOC conditions as conditions of certification **AQ-1** through **AQ-39** for the 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.
- The projects' emissions 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

Air Quality Table 22 maps out the relationship between Energy Commission conditions numbering and district condition numbering and proposed modifications to each condition.

AIR QUALITY Table 22
Mapping of Energy Commission and District Condition Numbering

Energy Commission	District	Energy Commission	District
AQ-SC1	(none)	AQ-17	D29.2
AQ-SC2	(none)	AQ-18	D29.3
AQ-SC3	(none)	AQ-19	D29.4
AQ-SC4	(none)	AQ-20	D82.1
AQ-SC5	(none)	AQ-21	D82.2
AQ-SC6	(none)	AQ-22	E193.2
AQ-SC7	(none)	AQ-23	E193.2
AQ-1	F2.1	AQ-24	E193.3
AQ-2	F52.1	AQ-25	E193.4
AQ-3	F52.2	AQ-26	I298.1
AQ-4	A63.1	AQ-27	I298.2
AQ-5	A63.2	AQ-28	K40.2
AQ-6	A99.1	AQ-29	K67.5
AQ-7	A195.6	AQ-30	A195.9
AQ-8	A195.7	AQ-31	D12.6
AQ-9	A195.8	AQ-32	D12.7
AQ-10	A327.1	AQ-33	D12.8
AQ-11	B61.1	AQ-34	E179.3
AQ-12	C1.7	AQ-35	E179.4
AQ-13	C1.8	AQ-36	E193.2
AQ-14	C1.9	AQ-37	E144.1
AQ-15	C1.10	AQ-38	C157.1
AQ-16	D29.1	AQ-39	E193.2

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 shall not be terminated without written consent of the Compliance Project Manager (CPM).

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

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide, for approval, an AQCMP 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: 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. All construction equipment vehicle tires shall be inspected and washed as necessary to be free of dirt prior to entering paved roadways.

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. Construction areas adjacent to any paved roadway below the grade of the surrounding construction area or otherwise directly impacted by sediment from site drainage shall be provided with sandbags or other equivalently effective measures to prevent run-off to roadways, or other similar run-off control measures as specified in the Storm Water Pollution Prevention Plan (SWPPP), only when such SWPPP measures are necessary so that the condition does not conflict with the requirements of the 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.

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. All vehicles that are used to transport solid bulk material on public roadways and 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;

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

C. Any other documentation deemed necessary by the CPM 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.

Verification: The AQCMM shall provide the CPM a Monthly Compliance Report to include:

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

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

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

AQ-SC5 Diesel-Fueled 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.

<u>Verification:</u> 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 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 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.

<u>Verification:</u> 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-SC7 The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with the Conditions of Certification herein. The Quarterly Operation Report shall specifically note or highlight incidences of noncompliance.

<u>Verification:</u> 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.

District Final Determination Of Compliance Conditions (SCAQMD 2014a)

The following SCAQMD conditions (**AQ-1** to **AQ-39**) apply to each unit of equipment, and the proposed HBEP facility as a whole.

FACILITY

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 determine 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 = 5.52 lbs/mmcf with duct firing.

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.

[Rule 1325]

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-SC7**).

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.

AES shall provide SCAQMD by December 31, 2018 with a notarized statement that HB Beach Boilers 1 and 2 and RB Boilers 6 and 8 are permanently shut down and that any re start 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% by weight. The circuit breakers shall be equipped with a 10% 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: 1.47 lbs/mmcf, PM10: 3.36 lbs/mmcf with no duct burner firing, 5.22 lbs/mmcf with duct burner firing.

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.

[Rule 1303 – Offsets]

<u>**Verification**</u>**:** The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). 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.

<u>Verification</u>: The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). 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 327.4 LBS/MMCF NOx emission limits shall only apply during turbine operation prior to CEMS certification for reporting NOx emissions.

[Rule 2012]

<u>Verification</u>: The project owner shall demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-7 The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15% O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

[Rule 1703-PSD, Rule 2005]

<u>Verification</u>: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-8 The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15% O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

[Rule 1703-PSD]

<u>Verification</u>: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-9 The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15% 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]

<u>Verification</u>: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-10 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-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-11 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-SC7**).

AQ-12 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 five per months, 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.

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

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-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-13 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-SC7**). 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 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%.

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.

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-SC7**). 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 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%.

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.

<u>Verification</u>: 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-SC7**). 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 conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NO_X emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SO_X 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, 75, and 50% without duct firing, and 100% 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-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
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-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
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% 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 theVOC 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]

<u>Verification:</u> 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
Formaldehyde	Approved District method	1 hour	Outlet of the SCR

The test shall be conducted at least once every year.

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 within 10%of 100% load.

[40 CFR 63 Subpart YYYY]

<u>Verification:</u> 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% 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% 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]

<u>Verification</u>: 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]

<u>Verification</u>: 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 two 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]

<u>Verification</u>: The project owner shall submit CEMS records to demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

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 = 60.139 * FF

Where, GHG is the greenhouse gas emissions in tons of CO2e 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-hours on the 12-month rolling average. The GHG emissions from this equipment shall not exceed 3,907,239 tons per year on a 12-month rolling average basis. The calendar annual average GHG emissions shall not exceed 1,000[2] lbs of carbon dioxide per net megawatt-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.

[Rule 1714]

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

AQ-26 This equipment shall not be operated unless the facility holds 19,625 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 83,662 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]

<u>Verification</u>: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC7**).

AQ-27 This equipment shall not be operated unless the facility holds 4,733 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

[2] The PDOC allows higher values, but the federal New Source Performance Standard published January 8, 2014 is expected to apply to this facility, which would limit carbon dioxide emission to 1,000 lbs per MWh.

after the start of operation, the facility holds 13,391 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-SC7**).

AQ-28 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-16**, **AQ-17**, and **AQ-18** are conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15% 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% 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 90 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-29 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 megawatts

[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.

SCR/CO CATALYST

AQ-30 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/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% 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 ammonia slip concentrations averaged on an hourly basis as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall submit all calibration results performed to the CPM within 60 days of the calibration date. The project owner shall submit all calibration results performed to the CPM within 60 days of the calibration date. 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-SC7**) 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.

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 parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5&. 7 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]

<u>Verification:</u> 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 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%. It shall be calibrated once every twelve months.

The exhaust temperature at the inlet of the selective catalytic reduction /CO Catalyst shall be maintained between 500-650 deg F except during start up and shutdowns

[Rule 1303(a)(1) – BACT]

<u>Verification</u>: 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) 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%. 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]

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

AQ-34 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-31**

Condition Number **AQ-32**

[Rule 1303(a)(1) – BACT]

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

AQ-35 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-33**

[Rule 1303(a)(1) – BACT]

<u>Verification</u>: 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 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]

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

<u>Ammonia Storage Tank</u>

AQ-37 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-38 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-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.

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AIR QUALITY APPENDIX AIR-1

Greenhouse Gas Emissions

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

SUMMARY

The Huntington Beach Energy Project (HBEP) project is a proposed addition to the state's electricity system. It would be an efficient, new, dispatchable natural gas-fired combined 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 will improve the efficiency of existing system resources, the addition of HBEP would contribute to a reduction of the California GHG emissions and GHG emission rate average. The relative efficiency of the 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 HBEP, affects all other power plants in the interconnected system.

While the HBEP burns natural gas for fuel and thus produces GHG emissions that contribute cumulatively to climate change, it will have a beneficial impact on system operation and facilitate a reduction in GHG emissions in several ways:

- When dispatched,[3] the 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 HBEP would contribute to a reduction of California and overall Western Electricity Coordinating Council system GHG[4] emissions and GHG emission rate average.
- The HBEP would provide fast start and dispatch flexibility capabilities necessary to integrate the large amounts of variable renewable generation (also known as "intermittent energy resources") expected to meet the state's renewable portfolio standard (RPS) and GHG emission reduction targets
- The HBEP would replace capacity and generation mostly provided by aging, high GHG emitting power plants, some of which 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 HBEP would replace less efficient generation in the South Coast local reliability area required to meet local reliability needs, reducing the GHG emissions associated

[3] 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.

[4] 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.

with providing local reliability services and facilitating the retirement of aging, high GHG-emitting resources in the area.

- The HBEP would facilitate to some degree the replacement of high GHG emitting (e.g., out-of-state coal) electricity generation that must be phased out to meet the State's new Emissions Performance Standard implemented by SB 1368.

CONCLUSIONS

The project 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 project would result in a cumulative overall reduction in GHG emissions from the state's power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant. 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 will enable these agencies to gather the information needed to regulate the HBEP project 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 project may be subject to additional reporting requirements and GHG reduction and trading requirements as these regulations are more fully developed and implemented.

Staff does not believe that the 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 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 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.

As a base load power plant, the HBEP is subject to the Greenhouse Gases Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.). The project would meet the standard with a rating of 0.479 metric tonnes CO_2 per megawatt-hour.

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

INTRODUCTION

GHG emissions are not criteria pollutants; they are discussed in the context of cumulative impacts. In December 2009, the U.S. Environmental Protection Agency (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. Regulating GHGs at the federal level is required by Prevention of Significant Deterioration Program (PSD) for sources that exceed 100,000 tons per year of carbon dioxide-equivalent emissions.

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[5], and GHG inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

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

Global warming potential is a relative measure, compared to carbon dioxide, of a compound’s residence time in the atmosphere and ability to warm the planet. Mass emissions of GHGs are converted into carbon dioxide equivalent (CO2E) metric tonnes (MT) for ease of comparison.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

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

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

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

Applicable Law or Regulation	Description
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule "tailors" GHG emissions to PSD and Title V permitting applicability criteria.
40 Code of Federal Regulations (CFR) Parts 51 and 52	A new stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) is also considered to be a major stationary source subject to Prevention of Significant Determination (PSD) requirements. For permits issued on or after July 1, 2011 PSD applies to GHGs if the source is otherwise subject to PSD (for another regulated NSR pollutant), and the source has a GHG potential to emit (PTE) equal to or greater than 75,000 TPY CO2e. The proposed facility modifications are subject to the GHG PSD analysis.
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 will be regulated by the ARB. 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%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.

AIR QUALITY GHG ANALYSIS

California is actively pursuing policies to reduce GHG emissions that include adding low-GHG emitting renewable electricity generation resources to the system. The GHGs evaluated in this analysis include carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFC), and perflurocarbons (PFC). CO_2 emissions are far and away the most common of these emissions; as a result, even though the other GHGs may have a greater impact on climate change on a per-unit basis due to their greater global warming potential as described more fully below, GHG emissions are often "normalized" in terms of metric tons of CO_2-equivalent (MTCO2E) for simplicity. Global warming potential (GWP) is a relative measure, compared to carbon dioxide, of a compound's ability to warm the planet, taking into account each compound's expected residence time in the atmosphere. By convention, carbon dioxide is assigned a global warming potential of one. In comparison, for example methane has a GWP of 21, which means that it has a global warming effect 21 times greater than carbon dioxide on an equal-mass basis. The carbon dioxide equivalent (CO2E) for a source is obtained by multiplying each GHG by its GWP and then adding the results together to obtain a single, combined emission rate representing all GHGs in terms of CO2E.

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

GLOBAL CLIMATE CHANGE AND CALIFORNIA

Worldwide, with the exception of 1998, over the past 132-year record the nine warmest years all have occurred since 2000, with the two hottest years on record being 2010 and 2005 (NASA 2013). 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. California Air Resources Board (ARB) estimated that the mobile source sector accounted for approximately 38% of the GHG emissions generated in California in 2009, while the electricity generating sector accounted for approximately 23% of the 2009 California GHG emissions inventory with just more than half of that from in-state generation sources (ARB 2011).

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

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

- Temperature rises between 3 and 10.5 ºF
- 6 to 20 inches or greater rise in sea level
- 2 to 4 times as many heat-wave days in major urban centers
- 2 to 6 times as many heat-related deaths in major urban centers
- 1 to 1.5 times more critically dry years
- Losses to mountaintop snowpack and water supply (e.g., according to the CCCC, Sierra Nevada snowpack could be reduced by as much as 70 to 90% by 2100 [CEC 2009c])
- 25 to 85% increase in days conducive to ozone formation
- 3 to 20% increase in electricity demand
- 10 to 55% increase in the risk of wildfires

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

The state has demonstrated a clear willingness to address global climate change (GCC) through research, adaptation[6], 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 **Electricity System GHG Impacts** 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 CAA. In reaching its decision, the Court also acknowledged that climate change results, in part, from anthropogenic causes (Massachusetts et al. v. Environmental Protection Agency 549 U.S. 497, 2007). The Supreme Court's ruling paved the way for the regulation of GHG emissions by U.S. Environmental Protection Agency (U.S. EPA) under the CAA.

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

- Endangerment Finding:[7] That the current and projected concentrations of the GHGs in the atmosphere threaten the public health and welfare of current and future generations; and
- Cause or Contribute Finding: That the combined emissions of GHGs from new motor vehicles and new motor vehicle engines contribute to the GHG pollution which threatens public health and welfare.

As a result, regulating GHGs at the federal level is now required by U.S. EPA's Prevention of Significant Deterioration Program (PSD) for sources that exceed 100,000 tons per year of carbon dioxide-equivalent emissions and federal rules 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.

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[8] emissions as a condition of state licensing of new electric

[6] 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).

[7] The Supreme Court is expected to once again review the endangerment finding in early 2014, according to an article published online October 15, 2013 by E & E Publishing.

[8] 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.

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 2014, ARB will complete 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 which affect the electricity sector directly include a 33% 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% of California's electricity supplies by renewable sources by 2020.

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

Adopt a regulation requiring the mandatory reporting of greenhouse gas emissions (HSC §38530). In December 2007, the ARB adopted a regulation requiring the largest electric power generation and industrial sources to report and verify their greenhouse gas emissions. The reporting regulation serves as a solid foundation to determine greenhouse gas emissions and track future changes in emission levels. Facilities which 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. Amendments are scheduled to be adopted in spring, 2014. 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[9] 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.

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% reduction in statewide GHG emissions from the electricity sector even though that sector currently only produces about 25% of the state's GHG emissions.

SB 1368,[10] 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[11] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 EPS applies to base load power from new 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

[9] 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)

[10] Public Utilities Code § 8340 et seq.

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

California.[12] If a project, instate or out of state, plans to sell base load electricity 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%. 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)]. At the January 12, 2012, Business Meeting, the Energy Commission opened an Order Instituting Rulemaking (12-OIR-1) to consider revisions to the EPS.

HBEP is 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 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, 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 WCI program to reduce California's GHG emissions to 1990 levels by 2020.

On January 8, 2014, in the Federal Register the US EPA proposed New Source Performance Standard (NSPS) for GHG emissions for new electric power plants (Federal Register, Volume 79, No. 5); the requirement is effective on the date of publication unless it is significantly revised. This new requirement would limit large natural gas-fired stationary combustion turbines to no more than 1,000 lbs CO_2 per MWh and small natural gas-fired stationary combustion turbines to no more than 1,100 lbs CO_2 per MWh. Large natural gas-fired stationary combustion turbines are those with heat input ratings greater than 850 MMBtu/h (approximately 100 MWe) and small natural gas-fired stationary combustion turbines are those with heat input ratings less than 850 MMBtu/h. According to U.S. EPA, the proposed NSPS limits apply to an electric generating unit if it supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year.

The proposed combined cycle turbines are expected to be able to comply with these new federal requirements but they may have to limit their operations somewhat to do so. Tables F.6 through F.8 on page 114 of the PDOC show the facility's total output in kilowatts (KW) from one power block and the corresponding net heat rate in higher heating values (HHV). A heat rate of 8,463 Btu per KWh (HHV) corresponds to a carbon dioxide emissions rate of 1,000 pounds of carbon dioxide per MWh. Under the new NSPS, the facility is likely to exceed the limit when operating in a one-on-one configuration (one combustion turbine plus steam turbine) with the combustion turbine operating at less than about 90% load (corresponds to 144,285 KW from the facility)

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

given the listed heat rate of 8,436 Btu/KWh at that load point. It is also likely to exceed the limit below about 80% turbine power (268,702 KW in a two-on-one configuration and 367,918 KW in a three-on-one configuration) with listed heat rates of 8,346 Btu/KWh for the two-on-one configuration and 8,449 for the three-on-one configuration. Therefore, the project should keep operating above these load points in order to comply with the NSPS. If the project needs to operate below these load points for short periods, more operations at higher loads are required to keep the emission rates on a 12-operating month rolling average below the NSPS limit.

ELECTRICITY PROJECTED GREENHOUSE GAS EMISSIONS

While electricity use can be as simple as turning on a switch to operate a light or fan, the system to deliver the adequate and reliable electricity supply is complex and variable. But 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[13] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

GHG EMISSIONS FROM THE PROPOSED FACILITY

Project Construction

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 HBEP project would involve 90 months of activity (not including start-up or commissioning). 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
HBEP, Estimated Maximum Annual Construction Greenhouse Gas Emissions

	CO_2	CH_4	N_2O	CO_2e
Construction Total (Metric Tons)	2,938	0.14	0.06	2,960

Source: HBEP 2014a

[13] See CEC 2009b, page 95.

Project Operations

The HBEP is a proposed natural-gas fired, combined-cycle, air-cooled, 939-megawatt (MW) electrical generating facility that will replace the existing Huntington Beach Generating Station. The proposed HBEP would consist of two three-on-one combined-cycle power blocks, with three Mitsubishi Power Systems Americas (MPSA) 501DA combustion turbine generators (CTG) and associated equipment in each block. The primary sources of GHG would be the natural gas fired combustion turbines. 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 actual annual emissions including all operations. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials.

The applicant provided data on the expected heat rates for different load scenarios and different configurations. For each configuration (1x1, 2x1, and 3x1), the applicant provided heat rates for five different power outputs ranging from about 50-60% load up to 100% load. The applicant also provided the expected number of hours the plant would operate under each scenario, and heat rates for start ups and shutdowns. As a base load power plant, the HBEP is subject to SB1368 Emission Performance Standard of 60% capacity factor. Therefore, the project must comply with the SB1368 Greenhouse Gas Emission Performance Standard of 0.500 MTCO2/MWh. The estimated annual GHG performance is 1,053.7 lb CO2e/net MWh, or 0.479 MTCO2e/MWh, which could meet the standard. However, under the new federal NSPS, the operation of the facility would have to be restricted somewhat as described above. The federal NSPS is equivalent to 0.454 $MTCO_2$ per MWh. Therefore the project would exceed the NSPS limit unless the applicant changes the operation profile to include more operations at higher loads.

Greenhouse Gas Table 3
HBEP, Estimated Potential Greenhouse Gas (GHG) Emissions

Emissions Source	Operational GHG Emissions ($MTCO_2$/MWh) [a]
Total Project GHG Emissions (MTCO2/yr)	1,997,634
Estimated Annual Energy Output (MWh/yr) [b]	4,170,821
Estimated Annualized GHG Performance ($MTCO_2$/MWh)	0.479

Sources: SCAQMD 2014a
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 estimated actual operating basis.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses the cumulative effects of GHG emissions caused by both construction and operation. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Staff is continuing to monitor development of AB 32 Scoping Plan implementation efforts and general trends and developments affecting GHG regulation in the construction and electricity sectors.

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.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

Operational impacts of the proposed project are described in detail in a later section titled "**Project Impacts on Electricity System**" 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.

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.

COMPLIANCE WITH LORS

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 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. 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 WCI program to reduce California's GHG emissions to 1990 levels by 2020. ARB staff continues to develop and implement regulations to refine key elements of the GHG reduction measures to improve their linkage with other GHG reduction programs. The project may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB. Similarly, the proposed facility modifications 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 HBEP as proposed would comply with California's Emissions Performance Standard of 1,100 lbs of carbon dioxide per MWh, but may have to restrict operations somewhat to comply with the new federal NSPS of 1,000 lbs carbon dioxide per MWh.

District Regulation XVII establishes preconstruction review requirements for GHGs and the facility is evaluated for these requirements in the PDOC beginning on page 40. HBEP would be a major PSD source. The district 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 facility. The current design proposed for the facility meets the BACT requirement for GHG emission reductions. The District determined that visibility modeling for PSD Class I areas was not required but did evaluate visibility impacts on PSD Class II areas. They found that the proposed project would not adversely affect visibility in the Class II areas analyzed.

CALIFORNIA ELECTRICITY AND GREENHOUSE GASES

California's commitments to dramatically reduce greenhouse gas (GHG) emissions over the next four decades include moving to a high-renewable/low GHG electricity system. However, natural gas-fired power plants--and the GHG emissions associated with their output--will still be integral to the reliable operation of the electricity system at the outset of this period. In the long-run, zero- and low carbon resources, including demand-side and storage resources, may provide a majority, if not all of the balancing services needed to integrate variable[14] renewable resources. However, the technologies that are

[14] Variable and intermittent are often used interchangeably, but variable more accurately reflects the integration issues of renewable into the California grid. Winds can slow across a wind farm or cloud cover

needed to do so are not expected to be available in sufficient quantities by the early- to mid-2020s to obviate the need for dispatchable, flexible natural gas-fired electricity generation. Furthermore, the 2017–2020 retirements of natural gas-fired generation resources in the Los Angeles and San Diego regions that use once through cooling (OTC) technologies and the closure of the San Onofre Nuclear Generating Station (SONGS) will require the development of natural gas-fired generation as part of the set of resources that will maintain local reliability.

The amount of new natural gas-fired capacity needed to provide reliable service to the customers of the state's investor-owned utilities, direct access providers and community choice aggregators over a ten-year planning horizon is determined in the California Public Utilities Commission's (CPUC's) Long-term Procurement Planning (LTPP) proceeding. The resulting portfolio of demand- and supply-side resources satisfies the state's loading order, which mandates development of cost-effective preferred resources (zero- and low-GHG emitting resources, such as energy efficiency, demand response, and renewable generation) in support of the state's climate change policies before authorizing the development/financing of conventional fossil resources.[15]

THE ROLE OF NATURAL GAS-FIRED GENERATION IN A LOW-GHG ENVIRONMENT

The need for natural gas-fired generation to reliably operate the electricity system is well established. On October 8, 2008, the Energy Commission adopted an Order Instituting Informational Proceeding (08-GHG OII-1) to solicit comments on how to assess the greenhouse gas impacts of proposed new power plants in accordance with the California Environmental Quality Act (CEQA).[16] A report prepared as a response to the GHG OII (CEC 2009a) defines the roles that natural gas-fired power plants fulfill in an evolving high-renewables, low-GHG system (CEC 2009b, pp 93 and 94). Such new facilities serve to:

1. Provide variable generation and grid operations support;

2. Meet extreme load and system emergency requirements;

3. Meet local capacity requirements; and,

4. Provide general energy support.

Variable Generation and Grid Operations Support

California's renewable portfolio standard (RPS) requires that the state's energy service providers meet 33% of retail sales with renewable energy by 2020; meeting GHG

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can shade portions of a solar field, temporarily reducing unit or facility output, but not shut down the unit or facility.

[15] The loading order is set forth in California's Energy Action Plans. Energy Action Plan I was adopted by the state's energy agencies in April/May 2003 and Energy Action Plan II in September 2005, An update to these plans was issued in February 2008.

[16] This need for gas-fired generation to reliably operate the system was reaffirmed in the CPUC decision authorizing Southern California Edison to procure new gas-fired generation in the Los Angeles Basin. D.13-02-015, See Decision Authorizing Long-Term Procurement for Local Capacity Requirements, February 13, 2013, p. 2.

emission reduction targets for 2050 will likely require a far higher percentage. Much of this energy will come from variable wind and solar resources to be developed in California, or on an "as generated" basis from neighboring states.

The California Independent System Operator (CA ISO) has identified an increased need for regulation services, "load-following" generation, and multi-hour ramping as a result of the increase in these variable ("intermittent energy") renewable resources, whose output changes over the course of the day, often in a sudden and unpredictable fashion. Dispatchable capacity must provide "regulation," small changes in output over a five minute period at CA ISO direction, requiring that the generator be equipped with automated generation control (AGC). "Load following" requires larger changes in output by the generation portfolio over a 5-minute to one-hour period. Multi-hour ramping needs require that units be dispatched, at CA ISO direction if necessary, over time periods of one to nine hours and wider ranges of output in aggregate, requiring dispatchable generation that can start and ramp up and down quickly and be capable of operating at relatively low load levels if the amount of dispatchable capacity and associated energy needed from these resources is to be minimized.

Natural gas-fired power plants are currently the only type of new facility that can provide these "ancillary" services in the quantities needed now and in the near future. While dispatchable hydroelectric plants can also provide them, the potential for adding hydroelectric resources to the system is limited. Nuclear, coal and geothermal facilities are generally more economic if operated at or near their design point (i.e., base loaded)[17] and therefore, not the preferred technology for providing ancillary services. While demand-side resources and storage may ultimately provide significant quantities of these ancillary services, only pumped hydro storage facilities are currently capable of doing so on a large scale.[18]

Historically, a large share of California's load-following and ramping needs have been provided by the natural gas-fired steam turbines built on the Pacific coast and in the San Francisco Bay Delta during the 1960s and 1970s. While these units were modified to operate successfully as load followers, they are not as efficient or economic as newer technologies. Several of these have retired as a result of the State Water Resource Control Board's (SWRCB's) policy on the use of OTC technologies; others are expected to retire by 2020. This represents a loss of capacity capable of operating at a very wide range of output and thus providing large quantities of ancillary services.

Local Capacity Requirements

The CA ISO has identified numerous local capacity areas (LCA) and sub-areas in which threshold amounts of capacity are required to ensure reliability. Transmission constraints prevent the import of sufficient energy into these areas under high load

[17] Issues can arise from: thermal fatigue due to cycling; difficulties starting and stopping solid or geothermal fuel supplies; significant inefficiencies at low loads or standby points used to avoid full shutdowns; and, significant capital outlays that make it necessary to operate the units as much as possible.

[18] In D.13-02-015, the CPUC provides the assumptions regarding demand response and storage that were used in estimating the residual need for gas-fired generation capacity to meet the estimated 2021 local capacity requirement (LCR) for the Los Angeles Basin local capacity area (LCA).

conditions to ensure reliable service without requiring specified amounts of capacity be generating or available to the CA ISO for immediate dispatch.

Reliable service requires that the CA ISO be able to maintain service under 1-in-10-year load conditions given the sequential failure of two major components (a large power plant and a major transmission line, for example); this requirement is imposed by the North American Electric Reliability Council (NERC). The amount of capacity needed in each of these areas (the local capacity requirement, or "LCR") is determined annually by the CA ISO; the LCR study process culminates in an annual *Local Capacity Technical Analysis*. The need for natural-gas fired capacity in LCAs stems in part from their predominantly urban nature and coastal location (i.e., fewer transmission lines into the coastal region as none are available from the west or ocean-side of the basin). The LCRs of the Greater Bay Area, Los Angeles Basin, San Diego and Big Creek-Ventura LRAs are too large to be met solely with non-natural gas fired generation; the renewable development scenarios compiled by the CPUC for use in the 2012 LTPP proceeding – and those being considered in the 2014 proceeding – indicate that only a share of the new capacity needed in the large LCAs can be expected to come from new renewable resources. This share is not sufficient to eliminate the need for new natural-gas fired generation in the Los Angeles Basin LCA, as evidenced by the procurement authorization issued in that proceeding.

Extreme Load and System Emergency Requirements

Sufficient capacity must exist to meet demand under very high load conditions or when generator outages reduce capacity surpluses to levels low enough to threaten reliability. Historically, generation capacity and demand response programs equal to 115% to 117% of forecasted annual peak demand have been deemed sufficient to meet reliability requirements.

General Energy Support

The loading order indicates the resources that the state intends to rely on to meet energy needs while reducing GHG emissions. While energy efficiency, demand response programs, renewable generation, and combined heat and power are preferred resources that are to be developed before natural gas-fired generation, they are not sufficient to meet the state's future energy demand and maintain the electric system's reliability. In addition, a significant share of the state's still-operating generation fleet is expected to shut down to comply with the SWRCB's OTC policy. Energy from natural gas-fired generation will increasingly be needed during a prolonged nuclear plant outage (for refueling for example) or during dry years, in which hydroelectric production is reduced.

QUANTIFYING THE NEED FOR NATURAL GAS-FIRED GENERATION

Prior to the deregulation of the California electricity system during the 1990's, the Energy Commission's power plant siting process considered the need for power plant development. SB 110 (Chapter 581, Statutes of 1999) eliminated the requirement that projects licensed by the Energy Commission be in conformance with an integrated assessment of need that was conducted by the Energy Commission until that time.

The need for new generation capacity to ensure reliable service in the investor-owned utility (IOU) service territories is now determined in the CPUC's biennial LTPP proceeding.[19] This proceeding is the forum in which the state's major IOUs are authorized to finance the development of new "least-cost, best-fit" generation (on behalf of either IOU customers or all ratepayers not served by publicly-owned utilities) needed to reliably meet electricity demand. This need, specified in terms of: (a) the MW of capacity needed; (b) the desired or required operating characteristics of the resource(s) to be financed; and (c) the location of proposed additions if required for local reliability, is a function of planning assumptions that reflect the state's commitment to dramatically reduce GHG emissions from the electricity sector. The MWs of capacity needed are driven by:

- Peak demand growth due to economic and demographic factors;
- Reductions in peak demand due to committed and uncommitted energy efficiency and demand response programs;
- Reserve margins (dependable capacity in excess of peak demand) needed to ensure system reliability, normally assumed to be 15 to 17% of peak demand, but also including any additional dispatchable capacity needed to ensure reliability given variation of renewable resources (e.g., wind or solar generation);
- Capacity to be provided by fossil-fired resources being developed by California-based investor-owned utilities pursuant to authorization by the CPUC in previous LTPP proceedings;
- Capacity to be provided by new renewable resources built/contracted with to meet the state's RPS; and,
- Capacity to be lost due to retirement, e.g., capacity expected to cease operation as a result of the SWRCB policy regarding the use of OTC.

The planning assumptions adopted for use in the LTPP proceeding, and thus determinant of the amount of new capacity authorized, consider both the state's "loading order" for resource development, as well as the expected development of specific types of preferred resources, including energy efficiency, demand response, and renewable generation. In other words, in authorizing the procurement/financing of dispatchable, natural gas-fired capacity by an IOU, the CPUC assumes that cost-effective amounts of preferred resources will have been procured.[20]

The authorization for Southern California Edison to procure natural gas-fired generation to meet local reliability needs in the Los Angeles Basin was granted in D.13-02-015 (February 13, 2013) in the CPUC's 2012 LTPP proceeding (R.12-03-014). The decision requires that Southern California Edison procure at least 1,000 MW and not more than 1,200 MW of new conventional natural gas-fired resources in order to replace in-basin capacity utilizing OTC expected to retire by the end of 2020. The decision did not consider any need for additional capacity as a result of the retirement of San Onofre.

[19] The need for new generation capacity to ensure reliable service by publicly-owned utilities (POU) is determined by the governing authorities of the individual utilities.

[20] Both the amount of natural gas-fired capacity conditionally authorized by the CPUC and the amount that will ultimately approved are dependent upon the amount of preferred resources that are assumed by the CPUC to be developed and a showing by the IOU that all cost-effective preferred resources available have been procured. See D.13-02-015, pp. 78 - 80

The CPUC does not require Energy Commission certification for a generation project to participate in a utility request for offers (RFOs), nor does the Energy Commission require a PPA for a project to be considered for certification. Requiring the sequencing of these processes would not only lengthen the time needed to bring projects on line and thus threaten system reliability, it would reduce the number of projects that could compete in utility RFOs. This could lead to non-competitive solicitations, unnecessarily raising ratepayer costs.

Energy Commission certification of fossil generation without a long-term PPA does not result in the development of more fossil generation than that needed to reliably operate the system. It is not expected that developers of new capacity, such as the developer of the proposed modified ESEC facility, would bring a project to completion without a long-term PPA with a utility that would guaranteed recovery of the investment of several hundred million dollars. Only one so-called “merchant plant” has been developed since the energy crisis (2000 – 2001) without a PPA, and the conditions that led to that merchant plant are specific to that one facility. This merchant plant, in turn, provides capacity and ancillary services that obviates the need for energy and capacity from other, new gas-fired generation and contributes to reduction in GHG emissions. However, if the new ESEC units were to be built and come on line without CPUC approval of a PPA, they would still: (a) displace energy from higher GHG-emission facilities, and (b) not “crowd out” renewable generation and demand-side programs (i.e., requirements/targets for the procurement of preferred resources will be unaffected).

ENERGY DISPLACEMENT AND CHANGES IN GHG EMISSIONS

Any assessment of the impact of a new power plant on system-wide GHG emissions must begin with the understanding that electricity generation and demand must be in balance at all times; the energy provided by any new generation resource simultaneously displaces exactly the same amount of energy from an existing resource or resources.[21] The GHG emissions produced by the HBEP are thus not incremental, but are partially or totally offset by reductions in GHG emissions from those generation resources that are displaced, depending on the relative GHG emission rates.

At renewable penetration levels of less than 33%, new natural gas-fired generation such as the modified ESEC facility displaces less efficient natural gas-fired generation[22] in a very straightforward fashion. It is reasonable to assume that the HBEP units would be dispatched (called upon to generate electricity) whenever they are a cheaper source of energy than an alternative - i.e., that they will displace a more expensive resource, if not the most expensive resource that would otherwise be called upon to operate. The costs of dispatching a power plant are largely the costs of fuel, plus variable operations and

[21] Over time, the development of demand-side and storage technologies that can cost-effectively substitute for generation as providers of regulation, load-following, and multi-hour ramping services may obviate the need for gas-fired generation, but this is not expected to occur soon enough to eliminate the need for gas-fired generation to replace retiring OTC units and San Onofre.

[22] At very low gas prices relative to coal prices, i.e., when electricity from natural gas is cheaper than that from coal, new gas-fired generation will displace coal-fired generation. In markets such as California, where GHG emissions allowance costs are a component of the market price, coal-fired generation is displaced even sooner due to its higher carbon content.

maintenance (O&M) costs, with the former representing the lion's share of such costs (90% or more). It follows that the new HBEP units would be dispatched when they burn less fuel per MWh than the resource(s) they displace, i.e., when they produce fewer GHG emissions. There are exceptions in theory, but not in practice.[23]

Holding the portfolio of generation resources constant, energy from new natural gas-fired plants displaces energy from existing natural gas-fired plants. In the longer-term, the development and operation of the HBEP would reduce the use of less efficient generation resources, and ultimately, to their retirement. By reducing revenue streams accruing to other resources (for the provision of both energy and capacity-related services, whether through markets or under a bilateral contract), the HBEP render these other facilities less profitable and riskier to operate. This follows from the fixed demand for energy and ancillary services; the developers of the HBEP cannot stimulate demand for energy and other products they provide, but merely serve to provide a share of the energy that is needed to meet demand and the capacity needed to reliably operate the system. In doing so, the HBEP both discourages the use of, and allows for the retirement of less-efficient generation.

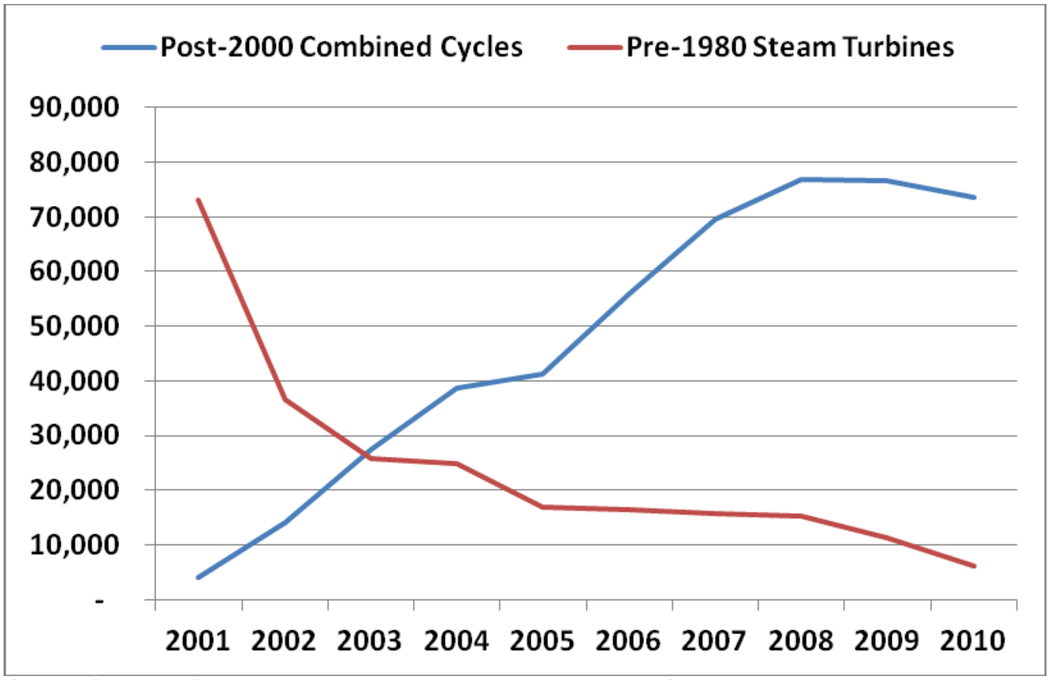
The long-run impact of the natural gas fired fleet turnover as described here can be seen from historical changes in resources that are providing electricity in California as presented below in **Figure GHG-1** (data includes combined cycles and boilers only). In 2001, approximately 74,000 GWh (62.5% of natural gas-fired generation) in California was from pre-1980 natural gas fired steam turbines, combusting an average of 11,268 Btu per kWh (not shown in the figure). By 2010, this share had fallen to approximately 6,000 GWh (5.4%); 64.1% of natural-gas fired generation was from new combined cycles with an average heat rate of 7,201 Btu per kWh (CEC 2011, also not shown in the figure).[24] The net change over this period was a 22% reduction in GHG emissions (also not shown in the figure) despite a 3.5% increase in generation. The post-2000 development of new combined cycle generation has allowed for the retirement of aging natural gas fired steam turbines along the California Coast and in the San Francisco Bay Delta. Those that remain in operation have seen a dramatic reduction in their capacity factors[25] and are used primarily as a source of dispatchable capacity.

[23] If a plant's variable O&M costs are so low as to offset the costs associated with its greater fuel combustion, a less efficient (higher GHG emission) plant may be dispatched first. There is no indication that the HBEP's' variable O&M costs are unusually low and that they would be dispatched before a more efficient facility. If a natural gas-fired plant's per-mmBtu fuel costs are very low, it may be less efficient (higher GHG emission) but still be dispatched first. Natural gas costs in California, however, are higher than elsewhere in the WECC and thus this scenario is unlikely to occur.

[24] The remaining 30% of natural-gas-fired generation is largely cogeneration; slightly more than one percent is from peaking units. For a detailed discussion of the evolution of natural gas-fired generation in California since 2000, see *Thermal Efficiency of Gas-Fired Generation in California: 2012 Update* (CEC-200-2013-002; May 2013)

[25] A unit's capacity factor is its output expressed as a share of potential output, the amount it would generate if it were operated continuously at 100%.

Figure GHG-1 Annual California Output (GWh), Selected Natural Gas-Fired Generation Technologies, 2001 – 2010



Source: Generator Quarterly Fuel and Report Filings with the Energy Commission

The dispatch of the HBEP would generally not result in the displacement of energy from renewable resources or large hydroelectric generation. Most renewable resources have must-take contracts with utilities, which must purchase all the energy produced by these renewable generators. Rare exceptions occur due to transmission congestion or seasonal surpluses. Even in those instances where this is not the case (e.g., where renewable generation is participating in a spot market for energy) the variable costs associated with renewable generation are far lower than those associated with the HBEP (e.g., fuel costs for wind, solar, other renewable generation technologies, and large hydroelectric facilities are zero or minimal); these resources can bid into spot markets for energy at prices far below the HBEP and other natural gas-fired generators. Nor would the HBEP displace energy from operating (zero-GHG emission) nuclear generation facilities, as these resources have far lower variable operating costs as well.

The relationship between a natural gas-fired plant's heat rate and its dispatch in the real world is in fact more complicated than that described above. While natural gas-fired plants differ in their thermal efficiency – the amount of fuel combusted, and thus GHG emissions per unit of electricity generated – very efficient natural gas plants are not necessarily dispatched before less efficient ones. While this would seem to contradict the assertion that output from a new plant will always displace a higher emitting one, a less efficient (e.g., at full output) plant may actually combust less fuel during a duty cycle than a plant with a lower heat rate, and thus produce fewer GHG emissions. Consider a 30-MW peaking plant with a heat rate of 10,000 Btu/kWh when operated at full output whose electrical outputs can be moved from off to on, generating approximately 15 to 30 MW in a matter of minutes. Use of this plant to meet contingency needs (e.g., demand on a hot afternoon) may result in less incremental fuel combustion than a 100 MW plant with a lower heat rate at full output if the latter requires several hours and combusts large amounts of fuel to start up, must be kept on overnight or for several hours in order to be available the next day and/or cannot operate at 30 MW (without a marked degradation in efficiency, and thus increases in GHG emissions).

At levels of renewable energy penetration in excess of 33%, flexible combined cycles such as the HBEP contribute to GHG emission reductions by increasing the amount of renewable energy that can be integrated into the electricity system. Given the solar-intensive generation portfolio being developed in California, increasing renewable penetration without curtailing renewable output more often will require an increasing ability to export surplus generation, store energy over a multi-hour period, and/or reduce gas-fired generation needed to reliably operate the system.[26] While the HBEP units are less thermally efficient than the natural gas-fired combined cycles built in California during the past decade, they are capable of operating at lower levels of output, and doing so without a marked decrease in efficiency. As a result, they can allow for more renewable generation that a conventional combined cycle, with the concomitant reduction in GHG emissions serving to offset the impact of their lower efficiency.

THE ROLE OF THE ESEC FACILITY ADDITIONS IN LOCAL GENERATION DISPLACEMENT

As new generation capacity in the California ISO-defined Los Angeles Basin local capacity area (LCA) and its Western Los Angele sub-area (LCA), the proposed HBEP would provide local reliability services. The CA ISO has determined in their *2014 Local Capacity Technical Analysis* that the Los Angeles Basin and its Western sub-area need 10,430 MW and 4,175 MW of local capacity, respectively.[27] The modified ESEC facility would contribute up to 334 MW of local capacity to these areas; in D.13-02-015[28] the CPUC has established the need for local capacity in excess of this amount to replace retiring OTC capacity in the Los Angeles Basin LCA.

As stated above, local reliability requires generation by resources located within an LCA; the LCR reflects the amount of capacity that must be generating, synchronous to the grid or available within a few minutes under 1-in-10 load conditions.[29] At lower levels of demand, a share of local capacity must be generating, synchronous to the grid or available on a moment's notice as long as reliability cannot be maintained solely with imported energy in the event of major component failures.

[26] 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.
[27] California ISO, *2014 Local Capacity Technical Analysis: Final Report and Study Results*, April 30, 2013, pp 75, 79.
[28] It is expected that the Energy Commission will receive AFCs from applicants expecting to provide additional local capacity well in excess of that authorized by [Decision #], as well as any additional amount authorized by forthcoming decisions in the 2014 LTPP proceeding. Approving AFCs for projects whose capacity in aggregate is in excess of that authorized by the CPUC facilitates competitive solicitations for new capacity and does not present a significant risk of the development of capacity in excess of the amount authorized;.
[29] 1-in-10 load conditions refer to a level of demand that is expected to be observed on only one day in ten years

The number of hours per year that the HBEP would be required to operate in support of local reliability needs and the amount of energy that would be generated as a result are not known; CA ISO operating procedures which result in the dispatch of specific generating units for local reliability purposes are confidential. When called upon to generate for such purposes, however, it is reasonable to expect that the HBEP would be the least-cost and thus lowest-emitting natural gas-fired resources able to do so, given the duty cycle that was necessary to provide local reliability. It would thus displace a less-efficient resource, reducing GHG emissions resulting from relying on the latter. Should it be dispatched for local reliability needs ahead of units that were thermally more efficient, it would likely be because, able to operate at lower levels of output, it would allow for the integration of a greater amount of renewable energy.

AVENAL PRECEDENT DECISION

The Energy Commission established a precedent decision in the Final Commission Decision for the Avenal Energy Project (CEC 2009b), 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
- take into account the two preceding factors, reduce system-wide GHG emissions”[30]

The average heat rate for the Western Electricity Coordinating Council (WECC) is presented in **Table GHG-**1

Table GHG-1 Weighted Average Heat Rate for Operating Natural Gas-Fired Plants[1] in the WECC 2010-2012

Year	Average Heat Rate (mmBtu/kWh)
2010	7,784
2011	7,995
2012	7,918

[1] Excludes cogeneration facilities
Source: Ventyx, Velocity Suite (compiled from EPA hourly Continuous Emission Monitoring Survey data

Despite having a heat rate in excess of the WECC average, the operation of the HBEP should result in a reduction in the system heat rate for natural gas plants in the WECC due to its displacing energy from less-efficient natural gas-fired generation as discussed above. In those instances where HBEP is higher emitting on a per-MWh basis that the resources it displaces but does so because it can operate at lower output levels and thus allow for more renewable integration and generation, the result might be a higher system heat rate, but total gas-fired generation (energy) and GHG emissions will fall.

[30] Final Commission Decision, Avenal Energy Application for Certification (08-AFC-1) December 2009, p. 114.

As noted above, the addition of HBEP would not interfere with generation from existing renewable facilities nor with the integration of new renewable generation. The flexible nature of the HBEP would in fact serve to facilitate the integration of additional variable renewable resources.

The HBEP would reduce system-wide GHG emissions as discussed above; their development is consistent the goals and policies of AB 32 and thus are consistent with the Avenal precedent decision.

PROPOSED CONDITIONS OF CERTIFICATION – TAO JIANG

No Conditions of Certification related to greenhouse gas emissions are proposed. The facility owner would participate in California's GHG cap-and-trade program. The facility owner 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 proposed facility modifications 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.

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ACRONYMS

AB	Assembly Bill
ARB	California Air Resources Board
CAA	Clean Air Act
CalEPA	California Environmental Protection Agency
Cal ISO	California Independent System Operator
CCCC	California Climate Change Center
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO2E	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
EIR	Environmental Impact Report
EPS	Emission Performance Standard
GCC	Global Climate Change
GHG	Green House Gas
GWh	Gigawatt-hour
GWP	Global Warming Potential
HBEP	Huntington Beach Energy Project
HFC	Hydrofluorocarbons
IEPR	Integrated Energy Policy Report
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
KW	Kilowatt
LRAs	Local Reliability Areas
MT	Metric tones
MW	Megawatt
MWe	Megawatt electrical
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
NOx	Oxides of Nitrogen or Nitrogen Oxides

OII	Order Initiating an Informational
OTC	Once-Through Cooling
PFC	Perfluorocarbons
POU	Publicly Owner Utility
PSA	Preliminary Staff Assessment (this document)
PSD	Prevention of Significant Deterioration
QFER	Quarterly Fuel and Energy Report
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SF_6	Sulfur hexafluoride
SWRCB	State Water Resource Control Board
U.S. EPA	United States Environmental Protection Agency

AIR QUALITY APPENDIX AIR-2
NITROGEN DEPOSITION ANALYSIS

Wenjun Qian, Ph.D., P.E. and Tao Jiang, Ph.D., P.E.

INTRODUCTION

The following provides a technical description of the preliminary nitrogen deposition analysis for the Huntington Beach Energy Project (HBEP). The contents and conclusions included here may be appended to the **BIOLOGICAL RESOURCES** section in the Final Staff Assessment.

PROJECT DESCRIPTION

The HBEP is a proposed natural-gas fired, combined-cycle, air-cooled, 939-megawatt (MW) electrical generating facility that would replace the existing Huntington Beach Generating Station. The proposed HBEP would consist of two three-on-one combined-cycle power blocks, with three Mitsubishi Power Systems Americas (MPSA) 501DA combustion turbine generators (CTG) and associated equipment in each block.

NITROGEN DEPOSITION

Nitrogen deposition is the term used to describe the input of reactive nitrogen species from the atmosphere to the biosphere. The pollutants that contribute to nitrogen deposition derive mainly from oxides of nitrogen (NOx) and ammonia (NH_3) emissions. NOx emissions (a term used for nitric oxide [NO] and nitrogen dioxide [NO_2]), generally the result of industrial or combustion processes, are much more widely distributed than NH_3. Reduced forms of nitrogen (NHx) are primarily emitted from intensive animal operations (e.g., dairies) and vehicles with the introduction of catalytic converters.

In the atmosphere NO_X is transformed to a range of secondary pollutants, including nitric acid (HNO_3), nitrates (NO_3) and organic compounds, such as peroxyacetyle nitrate (PAN), while NH_3 is readily absorbed by surfaces such as water and soil as well as being rapidly transformed to ammonium (NH4+) by reaction with acidic compounds. Both the primary and secondary nitrogen-based pollutants may be removed by wet deposition (scavenging of gases and aerosols by precipitation) and by dry deposition (direct turbulent deposition of gases and aerosols) on the earth’s surface.

NITROGEN DEPOSITION MODELS

Staff used the American Meteorological Society/Environmental Protection Agency Regulatory Model known as AERMOD to evaluate the potential nitrogen deposition impacts of this power plant project. AERMOD is a steady-state Gaussian plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and is applicable for use in both simple and complex terrain.

AERMOD does not account for the transformation of the N species which are time and reaction dependent. Therefore, it is a conservative model that overestimates deposition impacts. But, it is also approved for regulatory purposes for near-field impacts analyses (used by the Energy Commission and the air district), is most familiar to users and regulatory agencies, and it is generally used to estimate nitrogen deposition. Staff also used several assumptions with regard to nitrogen formation and deposition, which tend to further overestimate impacts. These assumptions include:

- 100% conversion of oxides of nitrogen (NOx) and ammonia (NH_3) into atmospherically derived nitrogen (ADN) within the exhaust stacks rather than allowing the conversion of NOx and NH_3 to occur over distance and time within the plume and atmosphere, which is beyond the scope of AERMOD;
- Depositional rates and parameters based upon nitric acid (HNO_3), which, of all the depositional species, has the most affinity for soils and vegetation and the tendency to adhere to what it is deposited on;
- Maximum settling velocities to produce maximum, or conservatively estimated, deposition rates;
- Emissions rates based upon the proposed facility's maximum potential to emit as required by California Environmental Quality Act (CEQA), rather than annually averaged likely emissions based on previous equipment performance and actual operations, in the calculation of nitrogen deposition; and
- Ammonia emissions are estimated to average 2.5 ppm, while the permit level is 5 ppm. In reality, ammonia emissions are generally less than 1 ppm over the life of the catalyst. Plant operators have an extraordinary impetus to avoid exceedances of their NOx permit limits, because they can be fined. Owners keep their catalyst clean and active, which keeps NOx level low and limits unreacted ammonia in the exhaust.

Assuming 100% of the NOx and NH_3 conversion to ADN within the exhaust stacks ignores the fact that it requires sunlight, moisture, and time for the nitrogen compounds to convert to ADN. Since staff analyzes habitat areas within a 6 mile radius of the project, it is unlikely that there would be sufficient time for the emitted nitrogen to convert to ADN. Therefore, it is likely that a less than significant amount of the project's nitrogen emissions would actually deposit on these habitat areas. However, at this time staff does not have refined data on the time needed for this conversion to occur. Therefore, staff conservatively assumes total conversion at the stack. The project would contribute to regional nitrogen deposition, but not at the levels predicted by AERMOD due to the limited time it takes for the plumes to travel to the habitat areas and the conservative assumptions used for nitrogen formation and deposition.

For average meteorological conditions, it would take the HBEP plumes less than 2 hours to reach the furthest habitat of interest. However, in urban atmospheres, the oxidation rate of NOx to HNO_3 is approximately 20% per hour, with a range of 10 to 30%per hour (ARB 1986). Nighttime NOx oxidation rates are generally much lower than typical daytime rates. HNO_3 is readily taken up by soil, vegetation, and water surfaces. HNO_3 also reacts with gaseous NH_3 to form ammonium nitrate (NH_4NO_3), but the reaction is reversible and dependent on temperature, relative humidity, and concentrations of other pollutants. The ambient concentration of nitrate is limited by the availability of NH_3, which is preferentially scavenged by sulfate (Scire et al 2000).

On the other hand, because NH_3 is readily taken up by damp soils and vegetation and by water bodies, a significant portion of the emitted NH_3 can be deposited to vegetation depending on the type of land cover and on meteorological conditions (Hatfield and Follett 2008). NH_3 is also readily taken up by aerosol particles of sulfuric acid (H_2SO_4) to form ammonium sulfate (($(NH_4)_2SO_4$ [Metcalfe et al 1999]). But since most $(NH_4)_2SO_4$ particles deposit to ground by rain, it is likely that less than significant amount of the $(NH_4)_2SO_4$ particles would actually deposit on the habitat areas within the 6 mile radius of the project (the average rainfall in Huntington Beach is less than 12 inches, with the majority falling between December and March). Instead, the $(NH_4)_2SO_4$ particles may travel hundreds and thousands of miles away from the project before they deposit on the earth's surface.

The Energy Commission's 2007 report *Assessment of Nitrogen Deposition: Modeling and Habitat Assessment* (Tonnesen et al 2007) reviewed two other air dispersion models, which can represent chemical speciation and formation of aerosols: CALPUFF and the Community Multiscale Air Quality (CMAQ) model for nitrogen deposition modeling. The CMAQ version used in the report sometimes produced relatively large numerical error thus the report concluded that CMAQ cannot be used reliably for single point source sensitivity simulations.

CALPUFF is a non-steady-state Lagrangian Gaussian puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on pollution transport, transformation, and removal by modeling parcels of air as they move along their trajectories. Different from AERMOD, CALPUFF uses simplified chemistry to attempt to represent nitrogen partitioning with relatively low computational cost compared to CMAQ. The Energy Commission's 2007 report concluded that the CALPUFF model can be used to simulate nitrogen deposition, and its results were generally similar in magnitude to the CMAQ-simulated nitrogen deposition. However, CALPUFF is more appropriate for long-range transport (i.e., greater than 50 kilometers – at less than 50 km, and for complex terrain, it requires regulatory approval for its use by the relevant reviewing agency). In addition, CALPUFF allows users to define certain parameters in its meteorological processor, which makes it difficult to be standardized for regulatory review purposes at the current stage.

Both AERMOD and CALPUFF have strengths and weaknesses in modeling nitrogen deposition as mentioned above. Based on staff's modeling experience and U.S. Fish and Wildlife Service's analysis on the Russell City Energy Center Project (USFWS 2010), nitrogen deposition rates at habitat areas within 6 miles of the project predicted from CALPUFF are usually an order of magnitude lower (i.e., $1/10^{th}$) than those from AERMOD. At this time, staff continues to believe AERMOD, with the overlay of conservative assumptions mentioned above, is the most conservative model to use for nitrogen deposition modeling.

Nitrogen Deposition Impacts and Mitigation Calculations

Staff used AERMOD with the assumptions mentioned above to conservatively estimate nitrogen deposition impacts from power plants. For HBEP, the applicant provided an AERMOD analysis evaluating the nitrogen deposition impacts of the proposed new units at HBEP (HBEP 2013ll). Staff expanded the analysis to cover more habitat areas with the same modeling assumptions used by the applicant, and compared the modeled point-source nitrogen deposition rates for the HBEP to baseline nitrogen deposition rates (as determined by Tonnesen et al. [2007], using 2002 data).

The analysis does not account for the net benefit from the discontinuation of the existing boilers at the Huntington Beach Generating Station. Although the Huntington Beach Generating Station is currently operating, and has NOx and ammonia emission rates similar to the HBEP units, at its current capacity factors it produces only a fraction of the maximum annual nitrogenous emissions that the proposed project would be permitted to produce. But the comparison of past actual emissions to future permitted emissions is another conservative assumption, as it is unlikely that the HBEP units would ever approach their permitted level of operation as California moves to a high renewable, low carbon (greenhouse gas or GHG) electricity generation system

Staff emphasizes that its modeling provides an overestimation of nitrogen deposition of the project, based on conservatisms layered upon conservatisms. However, it is the best tool we currently have that is accepted to provide a consistent, albeit extremely conservative result.

Staff used the conservatively modeled project nitrogen deposition impact and baseline nitrogen deposition (see more descriptions regarding baseline below) to compute the total nitrogen deposition rates on habitat areas. The results could be used to compute the acreage of affected habitat to include map zones where the total nitrogen deposition exceeds the critical load for each vegetation type. Staff considers that map zones below critical load are not significantly impacted by the project and does not require mitigation (see more details in the **BIOLOGICAL RESOURCES** section). The baseline nitrogen deposition rates used in staff's analysis are based on emission inventory for calendar year 2002 (see more details below). Staff believes that additional conservatisms are introduced by using the 2002 baseline nitrogen deposition rates as discussed below.

CALIFORNIA AND SOUTH COAST AIR BASIN BASELINE NITROGEN DEPOSITION

The baseline nitrogen deposition rates used in staff's analysis are from the Energy Commission's 2007 report (Tonnesen et al 2007), which provided the total nitrogen deposition on a rather coarse 4-km (2.5-mile) grid (4 km x 4 km, or 16 km^2) throughout California. The report used emission inventory data that were previously developed through the Western Regional Air Partnership (WRAP) to simulate annual air quality and visibility for calendar year 2002. The source categories included for the calendar year 2002 include: area sources, point sources, mobile sources, non-road mobile sources, road dust, off shore sources, Mexico emissions inventory, and biogenic emissions for Volatile Organic Compounds (VOC).

However, the U.S. EPA's enforcement efforts, implemented through the State Implementation Plan (SIP) enforced by the regional air districts' Air Quality Management Plan (AQMP, see more details in the **Air Quality** section), have significantly reduced nitrogen emissions from mobile and stationary sources sectors since 2002, and will continue those downward trends. **Appendix A-2 Figures Ndep-1a** and **Ndep-1b** show that both the actual and forecasted nitrogen emissions calculated from the NOx and NH_3 emissions (red solid lines) for all sources in South Coast Air Basin decrease significantly from year 2000 to year 2035. The nitrogen emissions from the NOx and NH_3 emissions are based on the mass fraction of nitrogen in NOx and NH_3. It should be noted that nitrogen constitutes about 82% of NH_3 by weight while it only constitutes about 30% of NOx by weight.

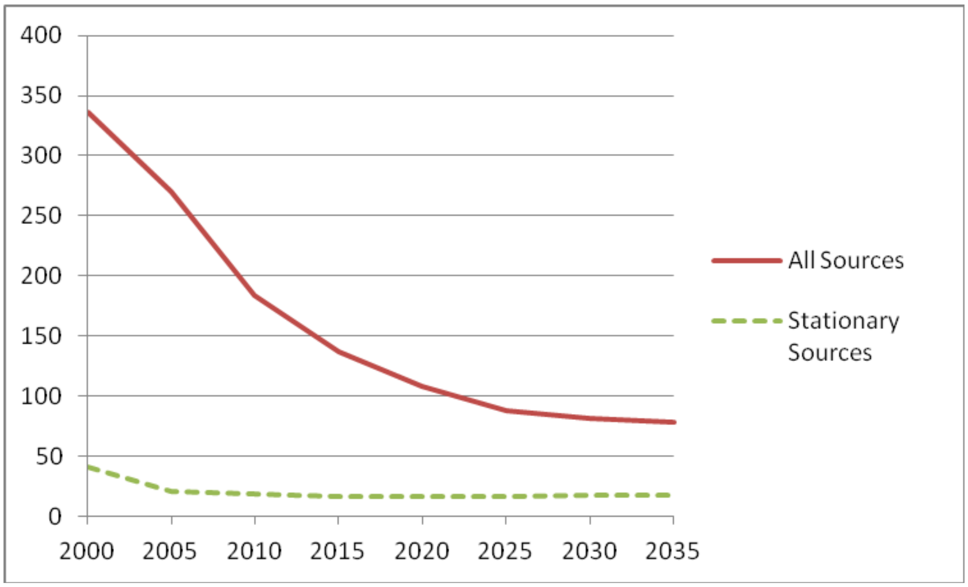
The emissions from stationary sources, including electric generation facilities, are also presented (green dashed lines) in the figures for comparison. NOx emissions from the stationary sources only account for 8 to 22% of those from all sources and also show a steady decrease over the years. Although the NH_3 emissions from the stationary sources, mainly waste disposal and fuel combustion, show a slight increase, they only account for 22 to 47% of the total emissions from all sources. The majority of the NOx emissions come from mobile sources and the majority of the NH_3 emissions come from area wide sources such as livestock operations, fertilizer applications, and mobile sources.

Appendix A-2 Figures Ndep-2 shows measured annual averaged nitrates (NO_3) and sulfates (SO_4) concentrations of dry particles at the San Gabriel monitoring station (located in South Coast Air Basin) from the Interagency Monitoring of Protected Visual Environments (IMPROVE) network. This is representative of depositional particles in ambient air at the station. The nitrates concentrations have decreased more than 50% from 2002 to 2012. The general trend of the sulfate concentrations is also decreasing. The sulfates concentrations have decreased about 30% from 2002 to 2012. This indicates that the reductions in the nitrogen emissions shown in **Appendix A-2 Figures Ndep-1a** and **Ndep-1b** are effective in reducing the background nitrates and sulfates in the South Coast Air Basin.

Considering the decreasing nitrogen emission inventory trend (an overall reduction of over 50% from 2002 to 2014, shown in **Appendix A-2 Figures Ndep-1a** and **1b** from the two trends for all sources combined), the relatively small contribution from the stationary sources, and the decreasing nitrates and sulfates concentration measurements, the use of 2002 emissions inventory in the baseline nitrogen deposition rates (shown in **BIOLOGICAL RESOURCES Tables 3** and **4** in the Supplemental Focused Analysis for the Preliminary Staff Assessment – Part A, TN# 201463) probably overestimates baseline deposition by a factor of two. Certain map zones that staff considered would be significantly impacted by the project, based on overestimated baseline as well as overestimated project impact, might have total nitrogen deposition below critical load. Thus the acreage of affected habitat is probably overestimated using 2002 baseline and conservatively estimated project impacts.

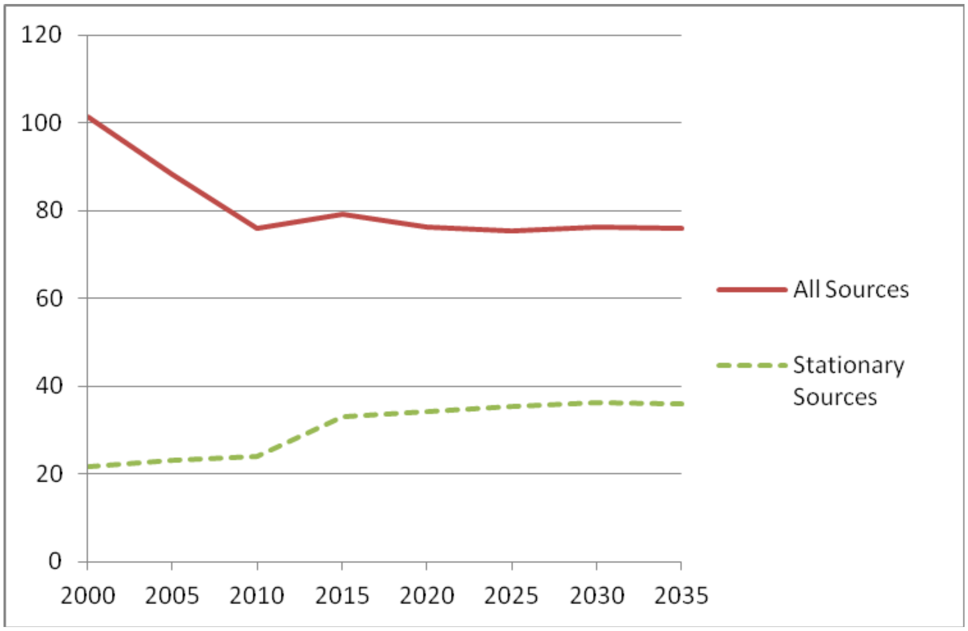
Staff assumes that total nitrogen loading is directly proportional to NOx and ammonia inventories. Since deposition pathways are complex and dependent on components such as time, humidity, sunlight exposure, and uniform mixing of needed reactants, deposition rates at the habitat areas near the project may be reduced more than the percentage change to nitrogen inventories.

Appendix Air-2 Figure Ndep-1a
Nitrogen portion[a] of the NOx Emissions Trends in South Coast Air Basin (tons/day, annual average)



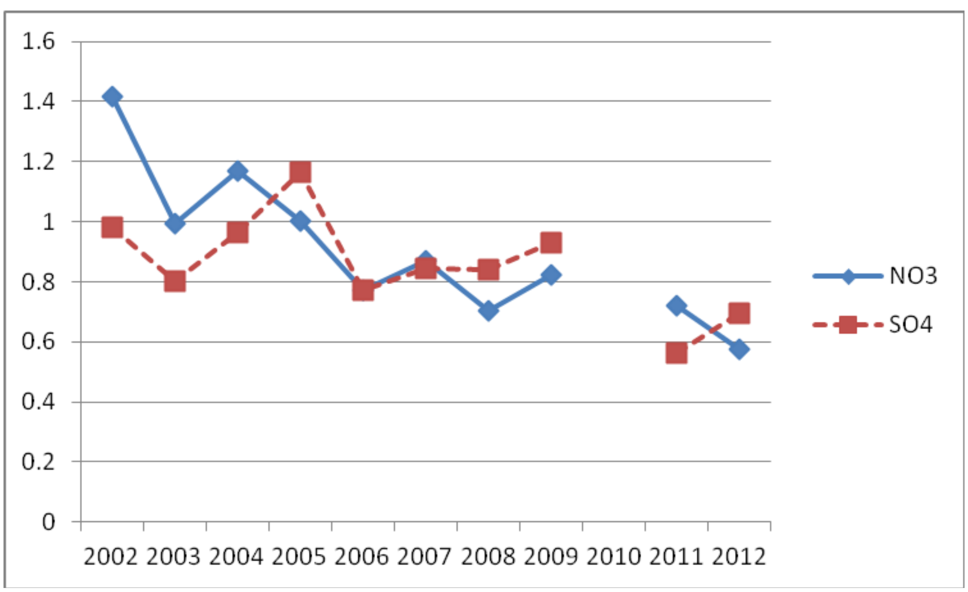
Source: The California Almanac of Emissions and Air Quality - 2013 Edition, Air Resources Board and Energy Commission staff analysis
Note: [a] The nitrogen portion of the NOx emissions is calculated based on the ratio between the molecular weight of nitrogen (14) and the molecular weight of NO_2 (46).

Appendix Air-2 Figure Ndep-1b
Nitrogen portion[a] of the NH_3 Emission Trends in South Coast Air Basin
(tons/day, annual average)



Source: The California Almanac of Emissions and Air Quality - 2013 Edition, Air Resources Board and Energy Commission staff analysis
Note: [a] The nitrogen portion of the NH_3 emissions is calculated based on the ratio between the molecular weight of nitrogen (14) and the molecular weight of NH_3 (17).

Appendix Air-2 Figure Ndep-2
Nitrates (NO_3) and Sulfates (SO_4) Concentrations (µg/m^3) Measured at San Gabriel Monitoring Station



Source: Interagency Monitoring of Protected Visual Environments (IMPROVE) and Energy Commission staff analysis

In addition, the South Coast Air Quality Management District (SCAQMD) implemented the Regional Clean Air Incentives Market or RECLAIM on January 1, 1994. Facilities subject to this program, such as HBEP, are required to purchase RECLAIM Trading Credits (RTCs) to offset their annual NOx emission increase in a 1-to-1 offset ratio. As a result, any new stationary source like HBEP would not result in a net increase in NOx emissions basin wide (see details in the **Air Quality** section regarding HBEP RECLAIM participation and compliance). In addition, since HBEP would be located in Zone 1 (South Coast Air Basin coastal zone) RTCs may only be obtained from Zone1. The resulting new emissions (potential NOx increases) from HBEP and the required RTCs (NOx reductions or offsets) would be balanced to zero, or no net increase, annually in the more local coastal zone. So the baseline nitrogen from NOx would not change due to NOx emissions from HBEP.

CONCLUSIONS

While staff can calculate a nitrogen deposition rate from the project, staff believes the modeling tools and background deposition rates identify a much higher rate of nitrogen deposition than is reasonably expected to occur. For more information on this, refer to the **BIOLOGICAL RESOURCES** section of this document.

Staff believes that because AERMOD does not account for the transformation of the nitrogen species, which is time and reaction dependent, the nitrogen deposition impacts of the project have been overestimated by as much as a factor of 10 using AERMOD. Further, the nitrogen emission inventory in the South Coast Air Basin has decreased more than 50% from 2002 to 2014 for oxides of nitrogen and ammonia combined. The use of the 2002 emissions inventory in the baseline nitrogen deposition rates probably overestimates baseline nitrogen deposition by a factor of 2. In addition, HBEP is required to purchase RTCs to offset their annual NOx emissions on a 1-to-1 offset ratio. HBEP would not result in a net increase in NOx emissions in South Coast Air Basin coastal zone. Lastly, ammonia emissions were modeled at a rate 2.5 times higher in the modeling than what is reasonably expected.

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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 proposed Huntington Beach Energy Project (HBEP). Staff's analysis of potential health impacts was based on a highly 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 project's air emissions.

INTRODUCTION

The purpose of this Preliminary Staff Assessment (PSA) is to determine if emissions of toxic air contaminants (TACs) from the proposed 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 toxic air contaminants, Energy Commission staff address the potential impacts of regulated, or criteria, air pollutants in the **AIR QUALITY** section of this PSA, and assess the impacts on public and off-site worker health 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.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Public Health Table 1 lists the federal, state, and local laws and policies applicable to the control of TAC emissions and mitigation of public health impacts for HBEP. This section evaluates compliance with these requirements and summarizes the applicable laws, ordinances, regulations and standards (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.”
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 ARB (California Air Resources Board) / 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 toxic air contaminants (TACs).

Applicable LORS	Description
Local	
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 toxic air contaminants (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 maximum individual cancer risk (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}).

SETTING

This section describes the environment in the vicinity of the proposed project site from a public health perspective. 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 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.

SITE AND VICINITY DESCRIPTION

The proposed 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 South Coast Air Quality Management District (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 HBEP is proposed as a natural gas-fired, combined-cycle, air-cooled, nominal 939-megawatt (MW) electrical generating facility. It would include two independently operating, three-on-one, combined cycle gas turbine power blocks (HBEP Block 1 and HBEP Block 2) and a shared common area. Each power block would consist of three natural gas-fired combustion turbine generators (CTGs), three supplemental duct-fired heat recovery steam generators (HRSGs), one steam turbine generator, one air-cooled condenser, and other related ancillary facilities. The turbines would use dry low NOx (oxides of nitrogen) burners and selective catalytic reduction to limit NOx emissions to 2 parts per million by volume (ppmv). Emissions of carbon monoxide (CO) would be limited to 2 ppmv and volatile organic compounds (VOCs) to 1 ppmv through the use of the best combustion practices and the use of an oxidation catalyst. HBEP would retain the use of the two existing 275-horsepower diesel-fired emergency fire water pumps, which were installed during the existing Huntington Beach Generating Station's Units 3 and 4 retooling project in 2001. Because the existing fire pumps are already permitted by the South Coast Air Quality Management District (SCAQMD) and are considered part of the existing background conditions, they were not included in the public health analysis for HBEP (HBEP 2012a, section 2.0).

The proposed HBEP site is located in an industrial area in Huntington Beach (HBEP 2012a, section 5.6). According to the Application for Certification (AFC), approximately 353,173 residents live within a 6-mile radius of HBEP, and the sensitive receptors within a 6-mile radius of the project site include (HBEP 2012a, 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 resident is 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 2012a, section 5.9.2).

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 2008 to 2012) for the John Wayne Airport meteorological station[1] show that the prevailing winds that blow to the proposed HBEP were mostly from the southwest. Only a small percent of prevailing winds blow to the proposed HBEP were from other directions (HBEP 2014b). Please refer to the **AIR QUALITY** section for more details.

EXISTING SETTING

As previously noted, the proposed HBEP site is located within the South Coast Air Basin (SCAB) and within the South Coast Air Quality Management District (SCAQMD). 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. When examining such risk estimates, staff considers it important to note that the overall lifetime risk of developing cancer for the average female in the United States is about 1 in 3, or 333,333 in 1 million and about 1 in 2, or 500,000 in 1 million for the average male (American Cancer Society, 2013). From 2005 to 2009, the cancer incidence rates in California are 51.05 in 1 million for males and 39.89 for females. Also, from 2005 to 2009, the cancer death rates for California are 19.49 in 1 million for males and 14.17 in 1 million for females (American Cancer Society, 2013).

EXISTING PUBLIC HEALTH CONCERNS

When evaluating a new project, staff usually conducts a study and analysis of existing public health issues in the project vicinity (i.e. areas within the same county or air basin). This analysis is prepared in order to identify the 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 proposed 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 proposed HBEP and assess the need for further mitigation.

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 diagnosed with asthma was reported as 6.0% in 2005-2007, compared to 7.7% for the general California population. Rates for children for the same 2005-2007 period were reported as 9.5% compared to 10.1% for the state in general (Wolstein et al., 2010).

[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. The applicant provided wind rose plots for the Costa Mesa meteorological station in the Appendix 5.1C of AFC. The applicant didn't update the wind rose plots after switching to use meteorological date from the John Wayne Airport. Staff generated wind rose plots using AREMOD.

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 2006 and 2010. These rates (of 15.08 per 1,000,000, combined male/female) were somewhat lower than the statewide average of 16.03 per 1,000,000 (National Cancer Institute, 2013).

There are some ambient monitoring sites for TACs in the SCAB. Air quality and health risk data in Table C-20 of California Almanac of Emissions and Air Quality – 2009 Edition (ARB, 2009) are for SCAB for years 1990- 2005. The data show a downward trend in TAC annual average concentrations, along with related cancer risks (ARB, 2009).

The Multiple Air Toxics Exposure Study II and III (MATES II and III) have been conducted in the SCAB by the SCAQMD Governing Board. MATES II and III consisted of a comprehensive monitoring program, an updated emissions inventory, and a modeling effort to characterize health risks associated with human exposures to ambient concentrations of TACs in the SCAB. Both the MATES II and MATES III studies showed that mobile sources, such as cars, trucks, trains, ships, and aircraft, represent the greatest contributors to estimated health risks in Orange County. About 70% of all carcinogenic risk is attributed to diesel particulate matter (DPM) emissions in MATES II; while about 84% of all carcinogenic risk is attributed to DPM emissions in MATES III. Overall, the general trend in risk exposure has been decreasing with the estimated cancer risk from exposure to airborne toxics (HBEP 2012a, section 5.9.2). The comparison of the county-wide population-weighted risk in Table 4-5 in the final report of MATES III showed the TAC reductions that occurred in Orange County, from 833 per million to 781 per million. SCAB follows the same trend, showing that TACs reduced from 931 per million to 853 per million (MATES III, 2008).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

This section discusses TAC emissions to which the public could be exposed during project construction/demolition and routine operation. Following the release of TACs into the air, water or soil, people would come into contact with them through inhalation, dermal contact, or ingestion, via contaminated food, water or soil.

Air pollutants for which no ambient air quality standards have been established are called non-criteria pollutants. Unlike criteria pollutants such as ozone, carbon monoxide, sulfur dioxide, or nitrogen dioxide, non-criteria pollutants have no ambient (outdoor) air quality standards that specify levels considered safe for everyone[2]. Since non-criteria pollutants do not have such standards, a health risk assessment (HRA) is used to determine if people might be exposed to those types of pollutants at unhealthy levels.

[2] Carbon dioxide (CO_2) is also a non-criteria pollutant, but it is also not considered a TAC at normal concentrations and is not evaluated in this analysis.

The standard approach currently used for a HRA involves four steps: 1) hazard identification, 2) exposure assessment, 3) dose-response assessment, and 4) risk characterization (OEHHA, 2003). These four steps are briefly discussed below:

1. Hazard identification is conducted to determine the potential health effects that could be associated with project emissions. For air toxics sources, the main purpose is to identify whether or not a hazard exists. Once a hazard has been identified, staff evaluates the exact toxic air contaminant(s) of concern and determines whether a TAC is a potential human carcinogen or is associated with other types of adverse health effects.

2. An exposure assessment is conducted to estimate the extent of public exposure to project emissions, including: (1) the worst-case concentrations of project emissions in the environment using dispersion modeling; and (2) the amount of pollutants that people could be exposed to through inhalation, ingestion, and dermal contact. Therefore, this step involves emissions quantification, modeling of environmental transport and dispersion, evaluation of environmental fate, identification of exposure routes, identification of exposed populations and sensitive subpopulations, and estimation of short-term and long-term exposure levels.

3. A dose-response assessment is conducted to characterize the relationship between exposure to an agent and incidence of an adverse health effect in exposed populations. The assumptions and methodologies of dose-response assessment are different between cancer and noncancer health effects. In cancer risk assessment, the dose-response relationship is expressed in terms of a potency (or slope) factor that is used to calculate the probability of getting cancer associated with an estimated exposure. In cancer risk assessment, it is assumed that risk is directly proportional to dose. It is also assumed that there is no threshold for carcinogenesis. In non-cancer risk assessment, dose-response data developed from animal or human studies are used to develop acute and chronic non-cancer Reference Exposure Levels (RELs). The acute and chronic RELs are defined as the concentration at which no adverse non-cancer health effects are anticipated. Unlike cancer health effects, non-cancer acute and chronic health effects are generally assumed to have thresholds for adverse effects. In other words, acute or chronic injury from a TAC would not occur until exposure to the pollutant has reached or exceeded a certain concentration (i.e., threshold).

4. Risk characterization is conducted to integrate the health effects and public exposure information and to provide quantitative estimates of health risks resulting from project emissions. Staff characterizes potential health risks by comparing worst-case exposure to safe standards based on known health effects.

Staff conducts its public health analysis by evaluating the information and data provided in the AFC by the applicant. 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 contaminants that cause cancer or other noncancer health effects, and identify the toxicity, cancer potency factors and non-cancer RELs of these contaminants. Staff relies upon the expertise of the California Air Resources Board (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.

For each project, a screening-level risk assessment is initially performed using simplified assumptions that are intentionally biased toward protection of public health. That is, staff uses an analysis designed to overestimate public health impacts from exposure to project emissions. In reality, it is likely that the actual risks from the source in question would be much lower than the risks as estimated by the screening-level assessment. The risks for such screening purposes are based on examining conditions that would lead to the highest, or worst-case, risks and then using those assumptions in the assessment. Such an approach usually involves the following:

- using the highest levels of pollutants that could be emitted from the plant;
- assuming weather conditions that would lead to the maximum ambient concentration of pollutants;
- using the type of air quality computer model which predicts the greatest plausible impacts;
- calculating health risks at the location where the pollutant concentrations are estimated to be the highest;
- assuming that an individual's exposure to carcinogenic (cancer-causing) agents would occur continuously for 70 years; and
- using health-based objectives aimed to protect the most sensitive members of the population (i.e., the young, elderly, and those with respiratory illnesses).

A screening-level risk assessment would, at a minimum, include the potential health effects from inhaling hazardous substances. Some facilities would also emit certain substances (e.g. semi-volatile organic chemicals and heavy metals) that could present a health hazard from non-inhalation pathways of exposure (OEHHA 2003, Tables 5.1, 6.3, 7.1). When these multi-pathway substances are present in facility emissions, the screening-level analysis would include the following additional exposure pathways: soil ingestion, dermal exposure, consumption of locally grown plant foods, mother's milk and water ingestion[3] (OEHHA 2003, p. 5-3).

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).

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.

[3] The exposure pathways of HRA for HBEP included inhalation, home grown produce, dermal absorption, soil ingestion, and mother's milk, not including water ingestion.

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% 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 standard setting. 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 (CAPCOA) 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 Risk and Estimation Process

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. 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 risk is expressed in terms 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 potency factors), 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.

As previously noted, the screening analysis is performed to assess the worst-case risks to public health associated with the proposed 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.

Acute and Chronic Noncancer Health Risks

As described earlier, 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 be 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 California OEHHA and U.S. 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 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 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, 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 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 significance 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.

DIRECT/INDIRECT IMPACTS AND MITIGATION

PROPOSED PROJECT'S CONSTRUCTION/DEMOLITION IMPACTS AND MITIGATION MEASURES

The construction and demolition period for HBEP would be approximately 7.5 years (HBEP 2013j). Construction of HBEP Power Blocks 1 and 2 would be coordinated with the operation and demolition of existing HBGS Units 1,2,3,4, and 5. Demolition of Unit 5, fuel tanks and Unit 3 & 4 stack, scheduled to occur between the first quarter of 2015 and the second quarter of 2016, would provide the space for the construction of HBEP Block 1. Construction of Power Blocks 1 and 2 are expected to take approximately 30 and 28 months, respectively, with Block 1 construction scheduled to occur from the third quarter of 2016 through the fourth quarter of 2018, and Block 2 construction scheduled to occur from the third quarter of 2018 through the second quarter of 2020. Removal/demolition of existing HBGS Units 1 and 2 is scheduled to occur from the fourth quarter of 2020 through the third quarter of 2022. Demolition of existing HBGS Units 3 and 4 is scheduled to occur from the first quarter of 2016 through the first quarter of 2018. However, the demolition of Units 3 and 4 is not part of the HBEP project definition. Although demolition of existing HBGS Units 3 and 4 is not part of the HBEP project definition, demolition of the Units 3 and 4 stacks would occur during removal of Unit 5 and is included in applicant's analysis. Please see **Project Description – Table 1** in this PSA for the details regarding the timeline of construction/demolition activity.

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 would cause the emission of asbestos. Asbestos is a mineral fiber that occurs in rock and soil. Because of its fiber strength and heat resistance, it has been used in a variety of building construction materials for insulation and as a fire-retardant. Asbestos has been used in a wide range of manufactured goods, mostly in building materials (roofing shingles, ceiling and floor tiles, paper products, and asbestos cement products), friction products (automobile clutch, brake, and transmission parts), heat-resistant fabrics, packaging, gaskets, and coatings (US EPA, 2012). Structures built before 1980 are more likely to have asbestos containing materials (ACM). Thermal system insulation (formed or spray-on) is the ACM of greatest concern for response and recovery worker exposure (OSHA).

Exposure to asbestos and asbestos containing materials (ACM) increases workers' and residences' risk of developing lung diseases, including asbestosis, lung cancer, and mesothelioma.

In Figure 2.2-2 and Figure 2.2-3 of the AFC, asbestos is listed under the removal of insulation of piping and boiler. Also, in page 4 of Appendix 5.14A (Phase I Environmental Site Assessment), Environmental Management Strategies, Inc. (EMS), it was noted that "the site buildings were constructed prior to 1980; therefore, asbestos-containing building materials and lead based paint may be present on-site." In Table 5.1-38, the applicant stated that they would comply with all requirements outlined in SCAQMD Rule 1403, which requires the notification and special handling of asbestos-containing materials during demolition activities (HEBA 2012a). The following actions were proposed by the applicant to comply with SCAQMD Rule 1403 (HEBA 2012n):

1. Prior to starting demolition activities, the applicant would conduct a facility survey to identify and quantify the presence of all friable and non-friable Class I and Class II asbestos-containing material (ACM). The survey would document the contact information and written qualifications for the person conducting the survey, survey dates, a listing of ACM, a sketch of where all samples were collected, contact information and a statement of qualifications for the laboratory conducting the ACM sample analyses, and sample test methods used with sampling protocols and laboratory methods.

2. The applicant (or its contractor) would notify the SCAQMD and California Energy Commission construction project manager (CPM) by letter of the intent to conduct demolition activities in a district-approved format no later than 10 working days prior to the start of any demolition activities. The notification would include:

    - whether it is original or revised,

- contact information for the applicant, supervising person, operator, asbestos removal contractor,
- facility address and location,
- a description of the affected parts (square feet/meters, number of floors, age, and present or prior uses) of the facility to be demolished,
- the specific location of ACM removal at the facility,
- schedule for starting and completing the demolition activity,
- a brief description of work practices and engineering controls to be employed to remove and handle ACM,
- an estimate of the amount of friable ACM and non-friable (Class I and Class II) ACM to be removed,
- name and location of the ACM waste disposal facility,
- procedures describing the identification of unexpected ACM or Class II non-friable asbestos,
- State Contractors License and Cal/OSHA Registration Numbers,
- procedures used to detect and analyze friable and non-friable asbestos, and
- certification that a trained person would supervise stripping and removal activities.

Notifications would be updated as appropriate to document if the quantity of affected asbestos changes by more than 20% and changes in the start and completion dates.

3. Asbestos removal would employ one or more of the following methods: High Efficiency Particulate Air (HEPA) Filtration, Glovebag or Minienclosures, Dray Removal, or an alternative approved method.

4. Collected ACM would be placed in a leak-tight container and would be handled and stored to avoid releasing ACM to the atmosphere. Storage containers would be appropriately marked with warning labels.

5. The applicant would designate an onsite representative to be present during all ACM demolition or handling procedures. The onsite representative would successfully complete the Asbestos Abatement Contractor/Supervisor course pursuant to the Asbestos Hazard Emergency Response Act and Provision of Title 40, Code of Federal Regulations, Parts 61.145 to 61.147, 61.152, and Part 763.

6. The applicant would dispose of ACM wastes at a licensed waste disposal facility and would maintain copies of the waste shipment records. ACM wastes would be hauled from the site by an appropriately licensed ACM waste transporter and the applicant would maintain copies of all manifests.

Small quantities of other hazardous wastes would be generated during construction/demolition of the project. The applicant stated that “hazardous waste management plans would be in place so the potential for public exposure is minimal”. 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 proposed project could occur from:

- dust entrained during site preparation and grading/excavation at the construction site;
- 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;
- exhaust from water trucks used to control construction 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 areas; and
- exhaust from vehicles used by construction 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 (diesel PM or DPM). Diesel exhaust is a complex mixture of thousands of gases and fine particles and contains over 40 substances listed by the U.S. Environmental Protection Agency (EPA) as hazardous air pollutants (HAPs) and by ARB as toxic air contaminants. The diesel particulate matter (DPM) is primarily composed of aggregates of spherical carbon particles coated with organic and inorganic substances.

Diesel exhaust deserves particular attention mainly because of its ability to induce serious noncancer effects and its status as a likely human carcinogen.

Diesel exhaust is also characterized by ARB as "particulate matter from diesel-fueled engines." The impacts from human exposure would include both short- and long-term health effects. Short-term effects can include increased coughing, labored breathing, chest tightness, wheezing, and eye and nasal irritation. Effects from long-term exposure can include increased coughing, chronic bronchitis, reductions in lung function, and inflammation of the lung. Epidemiological studies strongly suggest a causal relationship between occupational diesel exhaust exposure and lung cancer. Diesel exhaust is listed by the EPA as "likely to be carcinogenic to humans (US. EPA, 2003)."

Based on a number of health effects studies, the Scientific Review Panel on Toxic Air Contaminants in 1998 recommended a chronic REL for diesel exhaust particulate matter of 5 micrograms per cubic meter of air ($\mu g/m^3$) and a cancer unit risk factor of $3x10^{-4}$ $(\mu g/m^3)^{-1}$. The Scientific Review Panel did not recommend a specific value for an acute REL since available data in support of a value was deemed insufficient. Therefore, there is no acute relative exposure level (REL) for diesel particulate matter. In 1998, ARB listed particulate emissions from diesel-fueled engines as a toxic air contaminant and approved the panel's recommendations regarding health effects (OEHHA 2009, Appendix A). In 2000, ARB developed a "Risk Reduction Plan to Reduce Particulate Matter Emissions From Diesel-Fueled Engines and Vehicles" and has been developing regulations to reduce diesel particulate matter emissions since that time.

In Applicant's Response to Data Requests 74-77 and 107-109, a screening construction HRA for diesel particulate matter was conducted to assess the potential impacts associated with diesel emissions during the construction and demolition activities at HBEP. The results of the analysis are contained in **Public Health Table 2** (HBEP 2013j, HBEP 2013k, HBEP 2013aa, HBEP 2013ll).

The construction HRA was performed for a shorter exposure duration and different receptor locations. The total DPM exhaust emissions from construction/demolition activities were averaged over the 7.5-year construction period and spatially distributed in the area associated with the demolition of the Unit 5 peaker, Units 3 and 4 stack, and construction of Block 1; the area associated with the construction of Block 2; and the area associated with the demolition of Units 1 and 2 and the construction of buildings 33 and 34 (HBEP 2012c and HBEP 2013j).

This HRA was based on the annual average emissions of diesel particulate matter (DPM), assumed to occur each year for 9 years of continuous exposure[4]. This is because the HARP model limits short-term, continuous residential exposure to9years[5]. OEHHA Derived Methodology was used to determine the residential and sensitive

[4] Consistent with the OEHHA's guidelines, the risk assessment was conducted for different durations of exposure based on how long people live at a single location (9 years for the average, 30 years for a high end estimates, and 70 years for a lifetime) (OEHHA 2012, page 1-6). The scenario of 9-year exposure is consistent with construction activities because HARP cannot be used for shorter periods of time.

[5] According to OEHHA's guideline, "risk assessment were conducted for different durations of exposure based on how long people live at a single location (9 years for the average, 30 years for a high end estimates, and 70 years for a lifetime)" (OEHHA 2012, page 1-6).

receptor exposure cancer risk. An adjusted 9-year, 5-days-per-week, 10 hours-per-day, exposure duration was used for commercial/industrial receptors[6]. Staff only evaluates the health impact of 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).

Based on the applicant's analysis, the predicted incremental increases in cancer risk at the Point of Maximum Impact (PMI), Maximally Exposed Individual Resident (MEIR) and Maximally Exposed Individual Worker (MEIW) associated with construction/demolition activities are 12.3 in one million, 3.5 in one million and 11 in one million, respectively. The PMI for children is 18.2 per million. The predicted chronic health index at the PMI, MEIR and MEIW are 0.0461, 0.0131, and 0.115, respectively (HBEP 2013j, HBEP 2013k, HBEP 2013aa, HBEP 2013ll).

Public Health Table 2
Construction Hazard/Risk from DPMs calculated by the Applicant

				Significance Level	Significant?
Derived Cancer Risk (per million)	PMI	Adults	**12.3**	10	**Yes**
		Children	**18.2**	10	**Yes**
	MEIR	Adults	3.5	10	No
		Children	5.18	10	No
	at a Sensitive Receptor (Daycare)		1.86	10	No
	MEIW		**11**	10	**Yes**
Chronic HI (dimensionless)	PMI		0.0461	1	No
	MEIR		0.0131	1	No
	MEIW		0.115	1	No

Sources: HBEP 2013j, HBEP 2013k, HBEP 2013aa, HBEP 2013ll

The excess cancer risks at the PMI for both adults and children are higher than the California Environmental Quality Act (CEQA) significance threshold of 10 in one million, a level that does not necessary mean that adverse impacts are expected, but rather that further analysis and refinement of the exposure assessment is warranted. The applicant stated in Resubmission of Data Responses, Set 1B, 4, and 5 "*although the PMI and MEIW excess cancer risk is greater than 10 in one million, the elevated risk only occurs in areas where public access is controlled (i.e., within the AES-controlled fence line) or in areas that are not considered residential, commercial, or habitable, as presented in Figure DR109-1R. Additionally, any potential exposure would be sporadic and limited in length. Further, the predicted incremental increase in cancer risk at the MEIR and MEIW and chronic health index at the PMI, MEIR, and MEIW are less than the California Environmental Quality Act (CEQA) significance thresholds of 10 in one million and 1.0, respectively. Therefore, impacts associated with the finite construction activities are less than significant* (HBEP 2013ll, page 27)."

[6] Since the annual average determined by air modeling program is 24 hours per day, 7 days per week , 365 days per year regardless of the actual operating schedule of the facility, the adjustment factor = (7/5)×(24/10) = 3.36 (OEHHA, 2003, Chapter 8, pp.8-6).

Figure DR109-1R: HBEP Construction Excess Cancer Risk Assessment Isopleths 10 in One Million provided by the applicant, shows that the construction cancer risk exceeds the threshold of 10 in one million on the eastern fence line, in the adjacent open space area and a fuel oil tank farm - neither of which includes residential or commercial/industrial buildings (HBEP 2013ll). Staff agrees with the applicant and regards the related conditions of certification of **AQ-SC5** (Diesel-Fueled Engine Control) in the **AIR QUALITY** section as adequate to ensure that cancer-related impacts of diesel exhaust emissions for the public and off-site workers are mitigated during construction/demolition to a point where they are not considered significant. Staff also recommends the applicant be required to ensure there won't be any public access to this area during construction/demolition. Moreover, since the risk value is higher than the public notification levels of SCAQMD (i.e. ≥ 10 in one million), staff also recommends the applicant be required to follow SCAQMD's notification procedures (SCAQMD, 2011).

The chronic hazard indices for diesel exhaust during construction/demolition activities are lower than the significance level of 1.0. This means that there would be no chronic non-cancer impacts from construction/demolition activities.

The potential levels of criteria pollutants from operation of construction-related 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).

PROPOSED PROJECT'S OPERATIONAL IMPACTS AND MITIGATION MEASURES

Emission Sources

As previously noted, the proposed HBEP would be a natural gas-fired, combined-cycle, air-cooled, nominal 939-megawatt (MW) electrical generating facility. Pollutants that could potentially be emitted are listed in **Public Health Table 3,** including both criteria and non-criteria pollutants. These pollutants include certain volatile organic compounds (VOCs) and polycyclic aromatic hydrocarbons (PAHs). Criteria pollutant emissions and impacts are examined in staff's **AIR QUALITY** analysis. Since the facility would use dry cooling, there would be no emissions of toxic metals or VOCs from cooling tower mist or drift and no health risk from the potential presence of the Legionella bacterium responsible for Legionnaires' disease.

Tables 5.9-1, Table 5.9-2 and Table 5.1B.5 of the AFC (HBEP 2012a) list the specific non-criteria pollutants that would be emitted as combustion byproducts from the HBEP natural-gas-fired turbines. The emission factors for these pollutants were obtained from the ARB California Air Toxics Emission Factors (CATEF) emission database (ARB, 2012) and the AP-42 emission factors (HBEP 2013ll), with the exception of polyaromatic hydrocarbons (PAH) and formaldehyde. The PAH emission factor was based on two separate source tests (2002 and 2004) at the Delta Energy Center in Pittsburg, California (Avogadro Group, 2002 and 2004). The formaldehyde emission factor was 3.6×10^{-4} lbs/MMBtu, which was recommended by the SCAQMD (HBEP 2013ll).

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.

Public Health Table 3
The Main Pollutants Emitted from the Proposed 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
	Hexane
	Naphthalene
	Polycyclic Aromatic Hydrocarbons (PAHs, as BaP[a])
	Propylene
	Propylene oxide
	Toluene
	Xylene

Source: HBEP 2012a, Table 5.1-12, Table 5.9-1 and Table 5.9-2
[a] Benzo[a]pyrene

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 AFC, the toxic air contaminants emitted from the natural gas-fired CTGs/HRSGs 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 4
Types of Health Impacts and Exposure Routes Attributed to Toxic Emissions

Substance	Oral Cancer	Oral Noncancer	Inhalation Cancer	Noncancer (Chronic)	Noncancer (Acute)
Acetaldehyde			✔	✔	✔
Acrolein				✔	✔
Ammonia				✔	✔
Benzene			✔	✔	✔
1,3-Butadiene			✔	✔	
Ethyl Benzene			✔	✔	
Formaldehyde			✔	✔	✔
Napthalene		✔	✔	✔	
Polycyclic Aromatic Hydrocarbons (PAHs, as BaP)	✔		✔		
Propylene Oxide			✔	✔	✔
Toluene				✔	✔
Xylene				✔	✔

Source: OEHHA / ARB 2011 and HBEP 2012a, Table 5.9-1

Exposure Assessment

Public Health Table 4 shows the exposure routes of TACs and how they would contribute to the total risk obtained from the 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 2003) referred to earlier.

The next step in the assessment process is to estimate ambient concentrations using a screening air dispersion model and assuming conditions that would result in maximum impacts. The applicant used the EPA-recommended air dispersion model, AERMOD, along with 3 years (2005–2007) of compatible meteorological data from the Costa Mesa monitoring station, located approximately 3.5 miles northeast of the existing Huntington Beach Generating Station (HBEP 2012a, section 5.1.6.3).

Dose-Response Assessment

Public Health Table 5 (modified from Table 5.9-2 of the AFC, including neither oral cancer potency factor nor chronic oral REL) lists the toxicity values used to quantify the cancer and noncancer health risks from the project’s combustion-related pollutants. The listed toxicity values include RELs and the cancer potency factors are published in the OEHHA’s Guidelines (OEHHA 2003) and OEHHA/ARB Consolidation Table of OEHHA/ARB Approved Risk Assessment Health Values (ARB 2011). 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: ARB 2011 and HBEP 2012a, Table 5.9-2

Characterization of Risks from TACs

As described above, the last step in 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 applicant's HRA was prepared using the ARB's HARP model, version 1.4f (ARB, 2011) and HARP On-ramp program (version 1.0). The HARP On-ramp tool was used to import the American Meteorological Society/EPA Regulatory Model (AERMOD) air dispersion modeling results into the HARP Risk Module. Emissions of non-criteria pollutants from the project were analyzed using emission factors, as noted previously, obtained mainly from the ARB California Air Toxics Emission Factors (CATEF) emission database (ARB, 2012). Air dispersion modeling combined the emissions with site-specific terrain and meteorological conditions to analyze the mean short-term and long-term concentrations in air for use in the HRA. Ambient concentrations were used in conjunction with RELs and cancer unit risk factors to estimate the cancer and noncancer risks from operations. In the following sub-sections, staff reviews and summarizes the work of applicant, and evaluated the adequacy of applicant's analysis by conducting an independent HRA.

To evaluate the applicant's analysis, staff conducted another analysis of cancer risks and acute and chronic hazards due to combustion-related emissions from the proposed HBEP. 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.

Effective August 2012, all air toxics HRAs should use the new OEHHA's Air Toxics Hot Spots Program Risk Assessment Guideline (OEHHA 2012) which recommends breaking down exposure/risk by age group using age-dependent adjustment factors (i.e. Age Sensitivity Factors) to calculate the cancer risk. 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. Since HARP has not updated this new guideline, staff hand calculated the cancer risk at the Point of Maximum Impact (PMI) to check if cancer risks at this point exceed the threshold[7]. Human health risks associated with emissions from the proposed and similar projects are unlikely to be higher at any location other than the PMI. Therefore, if there is no significant impact associated with concentrations at the PMI, it can be reasonably assumed there would not be significant impacts in any other location in the project area.

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 staff's heath risk assessment for the HBEP:

- the analysis was conducted using the latest version (1.4f) of ARB/OEHHA Hotspots Analysis and Reporting Program (HARP);
- emissions are based upon concurrent operation of all six natural-gas-fired turbines. 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;
- exposure pathways included inhalation, home grown produce, dermal absorption, soil ingestion, and mother's milk;
- the local meteorological data, local topography, grid, residence and sensitive receptors, source elevations and site-specific and building-specific input parameters used in the HARP model were obtained from the AFC, Applicant's Responses to Data Requests (Public Health #74-77), Applicant's Responses to Data Requests (Public Health #107-109), and modeling files provided by the applicant;
- the emission factors and toxicity values used in staff's analysis of cancer risk and hazard were obtained from the AFC and Applicant's Responses to Data Requests

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7 Staff used the simplified formula modified from the one from OEHHA by assuming that the Average Daily Doses (ADD) are all the same at different time periods. The formula for Lifetime (70 year) exposure duration - Calculation of Cancer Risk from Third Trimester to Age 70 (OEHHA 2012, page 1-7) is:
Cancer Risk = $[(ADD_{\text{third trimester}} \times CPF \times 10) \times 0.3\ yrs/70\ yrs] + [(ADD_{0\ \text{to} <2yrs} \times CPF \times 10) \times 2\ yrs/70\ yrs] + [(ADD_{2 < 16yrs} \times CPF \times 3) \times 14\ yrs/70\ yrs] + [(ADD_{16 < 70yrs} \times CPF \times 1) \times 54\ yrs/70\ yrs]$
where:

ADD = Average Daily Dose, mg/kg-d, for the specified time period
CPF = Cancer Potency Factor $(mg/kg\text{-}d)^{-1}$
Age Sensitivity Factor third trimester to less than 2 years = 10
Age Sensitivity Factor age 2 to less than 16 years = 3
Age Sensitivity Factor age 16 to less than 70 years = 1

(Public Health #74-77), Applicant's Responses to Data Requests (Public Health #107-109) .The toxicity values are listed in **Public Health Table 5**;

- cancer risk was determined using the derived (OEHHA) risk assessment method. Staff applied the Age Sensitivity Factors recommended on OEHHA 2012 Guideline on the calculation of the cancer risk at the Point of Maximum Impact (PMI).

Cancer Risk at the Point of Maximum Impact (PMI)

The most significant result of HRA is the numerical cancer risk for the maximally exposed individual (MEI) which is the individual located at the point of maximum impact (PMI) and risks to the MEI at a residence (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 Maximum Incremental Cancer Risk (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, 70 year lifetime exposure. As shown in **Public Health Table 6**, total worst-case individual cancer risk was calculated by staff to be 4.32 in one million (the applicant calculated 2.54 in one million [HBEP 2013ll, Table DR107-1R] without applying the Age Sensitivity Factors) at the PMI. The PMI is approximately 0.27 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, whether the applicant's or staff's cancer risk is used, 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 acute Hazard Index (HI) of 0.00778 and a maximum chronic HI of 0.0781 (HBEP 2013ll, Table DR107-1R). 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 (MEIR is 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 exposure lasting 24 hours per day, 365 days per year, over a 70- year lifetime. Residential risks were presented in terms of MEIR and health hazard index (HHI) at residential receptors in **Public Health Table 6**. The cancer risk for the MEIR[8], is 2.2, which is below the significance level. The maximum resident chronic HI and acute

[8] 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, MEIR is not located at this position, but is located approximately 0.42 mile northeast of the HBEP fenceline.

HI[9] are 0.00691 and 0.0502, respectively (HBEP 2013ll, Table DR107-1R). They are both less than 1.0, indicating that no short- or long-term adverse health effects are expected at these residents.

Risk to Workers

The cancer risk to potentially exposed workers was presented by the applicant in terms of risk to the maximally exposed individual worker or MEIW at PMI and is summarized in **Public Health Table 6**. The applicant's assessment is for potential workplace risks uses a shorter duration exposure rather than the 70-year exposure used residential risks. Workplace risk is presently calculated by regulatory agencies using exposures of 8 hours per day, 245 days per year, over a 40- year period. As shown in **Public Health Table 6**, the cancer risk for workers at MEIW (i.e. 0.446 in 1 million) is below the significance level (HBEP 2013ll, Table DR107-1R). All risks are below the significance level.

Risk to Sensitive Receptors

As previously noted, the nearest sensitive receptor is a daycare facility located 0.3 mile east of the project site. The cancer risk at this daycare is 0.458 in one million, the chronic HI is 0.00144 and the acute HI is 0.018. The nearest school is the Edison High School, located approximately 0.5 mile to the northeast of the project site. The cancer risk at this school is 1.65 in one million, the chronic HI is 0.00519 and the acute HI is 0.0129 (HBEP 2013ll, Table DR107-1R). All risks are below the significance level.

In **Public Health Table 6**, it is notable that the cancer and noncancerous risks from 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, except for formaldehyde, which is discussed below.

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. Although the total combined potential HAP emissions from all 6 turbines at the site are approximately 21 tpy, formaldehyde emissions from the turbines exceed 10 tpy. Therefore, HBEP is classified as a major source of HAPs, subject to this subpart. In order to ensure that long-term routine operating emissions will not pose a significant risk to the off-site public, staff proposes that testing for formaldehyde be required, as per the requirements and schedules of Condition of Certification **AQ-19** in the **AIR QUALITY** section (SCAQMD 2014a, b).

[9] Resident chronic HI and resident acute HI are also located at different positions from the one specified in AFC.

Public Health Table 6
Cancer Risk and Chronic Hazard from HBEP Operations

Receptor Location	Cancer Risk (per million)	Chronic HI[e]	Acute HI[e]
PMI[a]	2.54 **4.32**[d]	0.00778	0.0781
Residence MEIR[b]	2.2	0.00691	0.0502
Worker MEIW[c]	0.446	0.00778	0.0781
Highest Cancer Risk at a Sensitive Receptor (Daycare)	0.458	0.00144	0.0183
Highest Cancer Risk at a Sensitive Receptor (Edison High School)	1.65	0.00519	0.0129
Significance level	10	1	1

[a] PMI = Point of Maximum Impact
[b] MEIR = MEI of residential receptors. Location of the residence of the highest risk with a 70-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 40 years (OEHHA, 2003, Chapter 8, pp.8-5).
[d] Cancer risk calculated by using the Age Sensitivity Factors recommended by OEHHA (OEHHA 2012). The cancer risk of PMI= ADD X CPF X [(10 X 0.3 yrs/70 yrs) + (10 X 2 yrs/70 yrs) + (3 X 14 yrs/70 yrs)+ (1 X 54 yrs/70 yrs)] = (2.54×10^{-6}) x (10 x0.3/70+10 x2/70+3 x14/70+1 x54/70) =4.32×10^{-6}
[e] 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 Regulation, Title 14, section 15130). As for cumulative impacts for cumulative hazards and health risks, if the implementation of the proposed 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 proposed project along with other projects within a 6-mile radius were not quantitatively evaluated in the AFC (HBEP 2012a, section 5.9.4).

The SCAQMD identified three facilities within 6 miles (~10 km) of HBEP for inclusion in the cumulative impact assessment of 1-hour NO_2 (HBEP 2013ee):

- Orange County Sanitation District (Facility ID 29110): located in Huntington Beach, California with seven emission sources

- Orange County Sanitation District (Facility ID 17301): located in Fountain Valley, California with five emission sources
- Beta Offshore (Facility ID 166903): located in Huntington Beach, California with 21 emission sources.

In addition to the above facilities, the SCAQMD also requested that emissions from shipping lane activity off the California coast be included in the cumulative impact assessment. The emissions from shipping lane activity off the California coast are not analyzed in the cumulative impact assessment due to different temporal and spatial factors.

Orange County Sanitation District's Huntington Beach facility is located approximately 1 mile southeast of the proposed HBEP site, Orange County Sanitation District's Fountain Valley facility is located approximately 3 miles northeast of the proposed HBEP site, while Beta Offshore is located approximately 3 miles northwest of the proposed HBEP site. The maximum cancer risk and non-cancer hazard index (both acute and chronic) for operations emissions from the HBEP estimated independently by the applicant, staff, and the SCAQMD 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. Staff, therefore, concludes that the proposed 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 proposed 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 4.32 in one million, which staff regards as not contributing significantly to the previously noted county-wide population-weighted risks of MATES III, 781 per million for Orange County and 853 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 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 proposed 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 of 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 cumulative significant public health impact on any population in the area. Therefore staff concludes that construction and operation of the HBEP would comply with all applicable LORS regarding long-term and short-term project impacts in the area of public health.

Additionally, staff reviewed the **Socioeconomics Figure 1**, which shows 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 proposed HBEP site. Because no members of the public potentially exposed to toxic air contaminant emissions of this project would experience acute or chronic significant health risk or cancer risk as a result, there would not be a disproportionate **Public Health** impact resulting from construction and operation of the proposed project to an environmental justice population.

PUBLIC AND AGENCY COMMENTS

Comment #1: John F. Scott submitted comments to the Energy Commission, dated October 23, 2012. Scott raised concerns regarding the health risk.

Comment #2: Morinka Horack submitted comments to the Energy Commission, dated November 14, 2012. Horack raised concerns that the residents have suffered greater health risks than they should.

Response: Staff has researched these issues and our report can be found above in the “Existing Public Health Concerns” and “Direct/Indirect Impacts and Mitigation” sections of this PSA. According to staff’s analysis, staff does not expect any significant adverse cancer, short-term, or long-term health effects to any members of the public, including low income and minority populations, from project toxic emissions.

CONCLUSIONS

Staff has analyzed the potential public health risks associated with construction and operation of the HBEP using a highly 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 air emissions. . According to the results of staff’s HRA, both construction 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.

ACRONYMS

AFC	Application for Certification
ARB	California Air Resources Board
ATC	Authority to Construct
Btu	British thermal unit
CAA	Clean Air Act (Federal)
CAL/EPA	California Environmental Protection Agency
CAPCOA	California Air Pollution Control Officers Association
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CTGs	Combustion Turbine Generators
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DPMs	Diesel Particulate Matter
FSA	Final Staff Assessment
HAPs	Hazardous Air Pollutants
HARP	Hot Spots Reporting Program
HRA	Health Risk Assessment
HBEP	Huntington Beach Energy Project (proposed project)
HI	Hazard Index
HRSGs	Heat Recovery Steam Generators
lbs	Pounds
LORS	Laws, Ordinances, Regulations and Standards
MACT	Maximum Achievable Control Technology
MICR	Maximum Individual Cancer Risk
mg/m^3	Milligrams per Cubic Meter
MMBtu	Million British thermal units
MW	Megawatts (1,000,000 Watts)
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
O_2	Oxygen
O_3	Ozone
OEHHA	Office of Environmental Health Hazard Assessment
PAHs (as BaP)	Polycyclic Aromatic Hydrocarbons (as Benzo[a]pyrene)

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 (this document)
RELs	Reference Exposure Levels
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SO_2	Sulfur Dioxide
SO_3	Sulfate
SOx	Oxides of Sulfur
SRP	Scientific Review Panel
TACs	Toxic Air Contaminants
T-BACT	Best Available Control Technology for Toxics
TDS	Total Dissolved Solids
tpy	Tons per Year
VOCs	Volatile Organic Compounds

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ALTERNATIVES

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INTRODUCTION

This section evaluates a reasonable range of potential alternatives to the proposed Huntington Beach Energy Project (HBEP or project). As the California Environmental Quality Act (CEQA) lead agency for the HBEP, the California Energy Commission (Energy Commission or staff) is required to identify and evaluate a range of reasonable alternatives to the project that would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project. The guiding principles for selection of alternatives analyzed are consistent with CEQA Guidelines (Cal. Code Regs., tit. 14, §15000 et seq.). These guidelines are described in detail below in the subsection “CEQA Requirements.”

Staff has reviewed the alternatives analysis provided by the project applicant within the HBEP Application for Certification (AFC) (HBEP 2012a). The information provided in the AFC served as a starting point for the alternatives analysis in this Preliminary Staff Assessment (PSA). Additionally, alternatives analyzed within this section include those recommended through agency and public comment, as well as those developed by staff.

Alternatives that have been evaluated are either eliminated from further consideration or evaluated against the HBEP to determine if they meet the basic objectives of the HBEP and would reduce or avoid any adverse environmental impacts of the HBEP. As discussed below, only the No-Project Alternative was determined to warrant detailed analysis and comparison to the HBEP at this time. Alternatives eliminated from detailed analysis are also discussed in this section, including the reasons for their elimination.

Based on the analysis provided in the **SOIL & WATER** Resources section, the HBEP would not result in significant impacts with respect to potable water use for process and steam makeup. Energy Commission and State Water Resources Control Board (SWRCB) policy directs power generation facilities to utilize recycled water when feasible. Therefore, staff has analyzed a recycled water supply alternative.

SUMMARY OF CONCLUSIONS

Based on the analysis provided below in the subsection “Alternatives Eliminated From Detailed Consideration,” the only alternative evaluated in detail is the No-Project Alternative, which consists of two power plant cooling retrofit scenarios of the existing Huntington Beach Generating Station (HBGS) compliant with the SWRCB Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. **Alternatives Table 1** provides a summary comparison of the HBEP environmental impacts and those of the No-Project Alternative. Based upon staff’s analysis, the No-Project Alternatives’ impacts would be similar to or less than those of the HBEP. The No-Project Alternatives reduce potential HBEP impacts due to a decreased construction schedule and overall reduction in operating hours of the HBGS when compared to the

HBEP. However, the No-Project Alternatives would only meet half of the basic objectives of the project.

CEQA REQUIREMENTS

As the CEQA lead agency for the HBEP, the Energy Commission is required to consider and discuss alternatives to the HBEP. The guiding principles for the selection of alternatives for analysis are provided by the CEQA Guidelines (Cal. Code Regs., tit. 14, §15000 et seq.). According to §15126.6 of the CEQA Guidelines, the alternatives analysis must:

- Describe a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project;
- Consider alternatives that would avoid or substantially lessen any significant environmental impacts of the project, including alternatives that would be more costly or would otherwise impede the project's objectives; and
- Evaluate the comparative merits of the alternatives.

The lead agency is responsible for selecting a reasonable range of project alternatives for examination and must publicly disclose its reasoning for selecting those alternatives (Cal. Code Regs., tit. 14, §15126.6[a]). CEQA does not require an agency to "consider every conceivable alternative to a project." Rather, CEQA requires consideration of a "reasonable range of potentially feasible alternatives." The reasonable range of alternatives must be selected and discussed in a manner that fosters meaningful public participation and informed decision making (Cal. Code Regs., tit. 14, §15126.6[f]). That is, the range of alternatives presented in this analysis is limited to those that will inform a reasoned choice by the Energy Commission. Under the "rule of reason," an agency need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative (Cal. Code Regs., tit. 14, §15126.6[f][3]).

The CEQA lead agency is also required to:

1. Evaluate a No-Project Alternative,
2. Identify alternatives that were initially considered but then rejected from further evaluation, and
3. Identify the environmentally superior alternative among the other alternatives (Cal. Code Regs., tit. 14, §15126.6)

Alternatives may be eliminated from detailed consideration by the lead agency if they fail to meet most of the basic project objectives, are infeasible, or could not avoid any significant environmental effects (Cal. Code Regs., tit. 14, §15126.6[c]).

PROJECT OBJECTIVES

The process for selecting alternatives to evaluate begins with the establishment of project objectives. CEQA Guidelines §15124 defines the requirement for a statement of objectives (Cal. Code Regs., tit. 14, §15124[b]):

> "A clearly written statement of objectives will help the lead agency develop a reasonable range of alternatives to evaluate in the EIR and will aid the decision makers in preparing findings or a statement of overriding considerations, if necessary. The statement of objectives should include the underlying purpose of the project."

The California Independent System Operator (CAISO) has identified the importance for new power generation facilities in their Los Angeles Basin Local Reliability Area to replace the ocean water once-through-cooling (OTC) plants that are expected to retire as a result of the California State Water Resources Control Board's (SWRCB) Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (referred to as the OTC Policy). The project objectives are also consistent with the use of the offset exemption contained within the South Coast Air Quality Management District's (SCAQMD) Rule 1304(a)(2) that allows for the replacement of older, less efficient, electric utility steam boilers with specific new generation technologies on a megawatt-to-megawatt basis.

The objectives for the HBEP are identified below.

- Provide efficient, reliable and predictable power supply by using combined-cycle, natural gas-fired combustion turbines to replace the OTC generation;
- Support the local capacity requirements of Southern California's Western Los Angeles Basin;
- Develop a 939 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 terrestrial 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.

ENERGY COMMISSION STAFF'S ALTERNATIVES SCREENING PROCESS

The California Environmental Quality Act Guidelines (State CEQA Guidelines) describe selection of a reasonable range of alternatives and the requirement to include those that could feasibly accomplish most of the basic project objectives while avoiding or substantially lessening one or more of the significant effects (Cal. Code Regs., tit. 14, § 15126.6, subd. (c)). The State CEQA Guidelines address the requirement for the alternatives analysis to briefly describe the rationale for selecting alternatives to be discussed. The analysis should identify any alternatives that were considered by the lead agency but were rejected as infeasible and briefly explain the reasons underlying the lead agency's determination.

The State CEQA Guidelines list factors that may be considered when addressing feasibility of alternatives: site suitability; economic viability; availability of infrastructure; general plan consistency; other plans or regulatory limitations; jurisdictional boundaries; and whether the proponent can reasonably acquire, control or otherwise have access to, the alternative site (or the site is already owned by the proponent). No one of these factors establishes a fixed limit on the scope of reasonable alternatives (Cal. Code Regs., tit. 14, § 15126.6, subd. (f)(1)).

Pursuant to CEQA, the purpose of staff's alternatives analysis is to identify the potential significant impacts of the HBEP and to focus on alternatives that are capable of avoiding or substantially reducing those impacts while still meeting most of the basic project objectives.

To prepare the analysis of alternatives, staff used the methodology summarized below:

- Describe the objectives of the project and compare those against potentially feasible alternatives to the project;
- Identify any potential significant environmental impacts of the project;
- Identify and evaluate feasible alternatives that meet most of the basic project objectives, to determine whether such alternatives would avoid or substantially lessen project impacts identified as significantly adverse, and determine whether such alternatives would result in impacts that are the same, less than, or greater than those of the project; and
- Evaluate the comparative merits of the alternatives.

PUBLIC AND AGENCY PARTICIPATION

Staff, in determining the scope and content of this analysis, has considered verbal and written agency, general public, and intervener comments received to date regarding alternatives to the HBEP. Preparation of the HBEP alternatives analysis included staff's participation in the following:

- Energy Commission Staff Workshop held in Huntington Beach, CA (November 14, 2012) – TN 68291.
- Energy Commission Environmental Scoping Meeting and Informational Hearing held in Huntington Beach, CA (September 10, 2012) – TN 67113.

The following identifies public and agency written comments received that pertain to the CEQA alternatives analysis of the HBEP:

- California Coastal Commission, TN 69246 (January 23, 2013) and TN 66483 (August 13, 2012): Requests that the alternatives analysis address the following:
    - Provide a comprehensive assessment evaluating alternative locations for currently proposed offsite construction activities that would result in coastal resource impacts (e.g., construction parking and staging that would adversely affect public access to the shoreline).

    - Potential alternative facility layouts that may reduce noise-related impacts.
    - Alternative configurations within the plant boundary could result in substantially fewer impacts to coastal resources; therefore, requests that the applicant provide for evaluation during the AFC proceedings feasible alternatives to the proposed locations of components of the various proposals to determine whether alternative layouts would avoid or reduce potential impacts to coastal resources, and requests that the application be supplemented to identify potential alternative locations for project components.
- City of Huntington Beach, TN 68804 – December 6, 2012: Requests that the alternatives analysis discuss the following:
    - Potential alternative facility layouts that would provide as much distance as possible from residences.
- Marinka Horack, TN 66382 – November 14, 2012: Requests that the alternatives analysis discuss alternative sites.
- Joanne Rasmussen, TN 68394 – November 5, 2012: Requests that the alternatives analysis discuss alternative facility layouts that may reduce noise-related impacts.
- Milton Dardis, TN 67501 – October 2, 2012: Requests that the alternatives analysis discuss alternative sites and alternative facility layouts that may reduce noise-related impacts.

ALTERNATIVES ELIMINATED FROM DETAILED CONSIDERATION

The CEQA Guidelines §15126.6(c) describe selection of a reasonable range of alternatives and the requirement to include those that could feasibly accomplish most of the basic project objectives while avoiding or substantially lessening one or more of the significant effects. The analysis should identify any alternatives that were considered by the lead agency, but were rejected as infeasible. CEQA requires a brief explanation of the reasons underlying the lead agency's determination to eliminate alternatives from detailed analysis.

The following alternatives were considered but eliminated from detailed consideration. Those alternatives that were not carried forward for full analysis include Alternative Sites, Alternative Site Configuration, and Technology Alternatives. The following provides staff's reasons for eliminating these alternatives from detailed analysis.

ALTERNATIVE SITES

Relationship of the Proposed HBEP to the Project Site

The Warren-Alquist Act addresses aspects of an applicant's site selection criteria for thermal power plants and the use of an existing industrial site for such use when the project has a strong relationship to the existing industrial site. When this is the case, it is "reasonable not to analyze alternative sites for the project" (Pub. Resources Code, § 25540.6, subd. (b)).

The discussion below addresses the project's strong relationship to the project site, both from a regulatory and practical standpoint, and provides a framework for staff's selection of project alternatives, and dismissal of off-site alternatives for further analysis.

Use of the Existing HBGS Site for Electrical Power Generation

The long-term historical use of the project site for electrical power generation is applicable to the discussion of the project's strong relationship to the site. This analysis recognizes the fact that the proposed HBEP would be constructed and operated at the existing HBGS site, which began operating in 1958 when it was owned by Southern California Edison (SCE). The power plant used fuel oil to produce electricity through its five generating units until the late 1980s when the generating units were converted for natural gas operation. In 1995, SCE retired generating Units 3 and 4 due to their limited use.

AES Southland Development, LLC, (AES) acquired the HBGS from SCE in 1998. In 2001, AES filed an Application for Certification with the Energy Commission to rebuild and upgrade (i.e., retool) Units 3 and 4 to meet increased electrical demand in California. The HBGS retool project for Units 3 and 4 was approved by the Energy Commission in 2001, and the total electrical generation capacity of the project was subsequently increased to 1,103 megawatts (MW). Units 1 through 5 were operational until October 2002. At that time, an order from South Coast Air Quality Management District resulted in the permanent removal of Unit 5 (a combustion turbine unit) from operation, and all permits for that unit were surrendered.

Expansion of Existing Coastal Power Plants

The California Coastal Act of 1976 (Coastal Act) protects coastal resources from the major impacts of power plant siting. In 1978, the California Coastal Commission (Coastal Commission) adopted a report that satisfied a requirement of the Coastal Act to designate specific locations in the coastal zone where the location of an electric generating facility would prevent the achievement of the objectives of the Coastal Act (Pub. Resources Code § 30413(b)). The 1978 report was revised in 1984 and re-adopted in 1985 (Coastal Commission 1985). In accordance with the Coastal Act, the report designates sensitive resource areas along the California coast as unsuitable for power plant construction and provides "that specific locations that are presently used for such facilities and reasonable expansion thereof shall not be so designated." This policy encourages expansion of existing power plant sites if new plants are necessary, thereby protecting undeveloped coastal areas (Coastal Commission 1985).

In a related effort, the Energy Commission prepared a 1980 study that examined opportunities for the reasonable expansion of existing power plants in the State's Coastal Zone and reviewed the effects of the designated resource areas on expansion opportunities (Energy Commission 1980). The 1980 study defines "reasonable" in this context to mean the provision or maintenance of land area adequate to satisfy a specific site's share of the State's need for increased electrical power generating capacity over the Energy Commission's planning intervals of 12 and 20 years (Energy Commission 1980). The study also gives practical consideration to coastal power plant expansion and siting opportunities. The ancillary support facilities already exist at the power plant sites, and the industrial-type land use has been established, which are important points to consider from a practical standpoint (Energy Commission 1980).

The expansion areas should be inside or adjacent to the existing site boundaries, or within a distance that would permit the cost effective use of the existing power plant support facilities, where necessary or advisable. The 1980 study acknowledged that other conventional siting factors (e.g., local land use plans) could affect expansion opportunities. The Energy Commission study is not intended to be used to endorse specific sites or types and sizes of power plants for expansion.

The 1980 study describes expansion opportunities for various combinations of plant types and sizes at 20 of the 25 evaluated sites. The Huntington Beach power plant is characterized as having “moderate expansion opportunities” while avoiding sensitive habitat and designated resource areas (Energy Commission 1980). The proposed HBEP would be located inside the existing HBGS, and no off-site expansion of power plant facilities would be required.

City of Huntington Beach General Plan

The City of Huntington Beach (City) General Plan (General Plan) includes goals, policies, and maps pertaining to the Huntington Beach power plant, which is called the Edison Plant in some General Plan documents. References to the Edison Plant associate the power plant to the period when the plant was owned by SCE. The HBGS site is in an area designated as Public (P) in the Land Use Element (City of Huntington Beach 2013). Typical permitted uses include public utilities. The Land Use Element includes a “Community District and Subarea Schedule” that describes the intended functional role of each subarea. The existing HBGS is in Subarea 4G, Edison Plant, where permitted uses include “utility uses” and “wetlands conservation” (due to the wetland areas abutting the southeast border of the HBGS).

The Coastal Element was prepared to “meet the requirements of the Coastal Act and guide civic decisions regarding growth, development, enhancement and preservation of the City’s Coastal Zone and its resources.” The Coastal Element was initially certified by the Coastal Commission in 2001. A comprehensive update to the Coastal Element was completed by the City in 2011 to ensure consistency with the policies and format of the 1996 General Plan (City of Huntington Beach 2011). The Coastal Element includes a detailed discussion and inventory of existing land uses, facilities, and resources in the Coastal Zone. The existing project site is identified as a “regionally serving electrical generating plant.” It is the policy of the Coastal Element to allow for the continuation, and in some cases expansion of energy facilities, while ensuring the community’s public health and safety, environmental protection, and minimization of environmental impacts to the maximum extent feasible (City of Huntington Beach 2011). Applicable goals and policies include Goal C8: “Accommodate energy facilities with the intent to promote beneficial effects while mitigating any potential adverse impacts.” Objective C8.2 addresses energy production: “Encourage the production of energy resources as efficiently as possible with minimal adverse impacts.” (Please refer to the other resource sections of this staff assessment for further details on applicable General Plan policies, goals, and objectives.)

The General Plan recognizes the existing use of the HBGS site and includes references to potential proposals to expand or alter the facility. Provided that mitigation measures are implemented to reduce potentially significant effects, continued use of the site for energy production is consistent with the Coastal Element. The General Plan is internally consistent in its descriptions of the existing energy facility and the goals, policies, and objectives pertaining to its use for that purpose. Energy Commission staff continues to work with city staff on various compliance issues pertaining to development, construction, and operation of the proposed HBEP.

Potential for the Proposed HBEP to Contribute to Local Grid Capacity Requirements

CAISO regularly evaluates grid reliability issues in its balancing authority area for the state. The proposed HBEP would be located in the Los Angeles Basin (LA Basin) local reliability area, which requires a minimum amount of electrical generation to maintain grid reliability; the specific number of needed megawatts is reported in annual CAISO transmission plan studies. The shutdown of the San Onofre Nuclear Generating Station (SONGS) in 2013 and the SWRCB policy restricting the use of coastal waters for the once-through cooling of power plants could significantly reduce the amount of generation available in the LA Basin. The most recent CAISO Transmission Plan evaluates the potential impacts of the SONGS shutdown and the SWRCB once-through cooling policy on grid reliability in California.

Approximately 30% of California's in-state generating capacity (gas and nuclear power) uses coastal and estuarine water for the once-through cooling (OTC) systems of power plants. On May 4, 2010, the SWRCB adopted a statewide policy (OTC Policy) on the use of coastal and estuarine waters for power plant cooling. The OTC Policy minimizes the use of coastal or estuarine water for OTC by power plants. Power plants in the LA Basin affected by this policy include the AES Alamitos facility (2,000 MW), the AES Huntington Beach facility (450 MW), and the AES Redondo Beach facility (1,310 MW). To comply with the OTC Policy, these generators must be retrofitted, repowered, or retired.

CAISO develops and publishes its annual Transmission Plan, which includes a comprehensive evaluation of the CAISO transmission grid identifying the upgrades required to successfully meet California's energy policy goals, maintain grid reliability requirements, and provide economic benefits to consumers. The most recent plan adopted by the CAISO Board of Governors, the 2012–2013 Transmission Plan, evaluates issues relating to power generators' compliance with the SWRCB ruling on OTC (CAISO 2013a), and includes an initial study of the long-term impacts of the SONGS shutdown.

The proposed HBEP is located within the LA Basin local reliability area. Absent SONGS (which provided 2,246 MW from Units 2 and 3 at full capacity), the CAISO projects a need for approximately 10,000 MW of generating capacity in the LA Basin (CAISO 2013a, page 128). A total of 11,789 MW of generation exists or is under construction in the LA Basin (CAISO 2013b, page 98). If the AES OTC plants are not retrofitted or repowered and are retired to comply with the OTC Policy, approximately 8,000 MW of capacity would be available in the LA Basin, which is insufficient capacity to meet the

CAISO local area requirements. Use of the existing Huntington Beach site to help meet known local electrical capacity requirements makes practical sense given the site's history of power generation, the existing site infrastructure, and the uncertainty of identifying other potentially feasible sites to replace the HBGS in a highly developed and densely populated region.

Alternative Site Summary

Any alternative that would, in theory, require conversion of some other area of similar acreage to a new electrical power generation facility would bring into question some of the feasibility issues listed above. AES owns and has full access to the HBGS site. 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 extent to which development of a different site could meet the project objectives is unknown, although it is questionable whether any off-site alternative would allow the project to remain a viable proposal given the likely extreme project schedule delay that would accompany a change of project site. In that circumstance, none of the project objectives would be attained for the proposed HBEP. Staff's analysis provides evidence of the proposed project's strong relationship to the project site, and given the uncertain potential for development of any alternative site to achieve the project objectives, no alternatives are considered that would entail decommissioning and retiring the existing power plant.

ALTERNATIVE SITE CONFIGURATIONS

As described earlier within the subsection "Public and Agency Participation," agency and public comments requested the alternatives analysis include alternative site configurations. As noted in these comments, the focus of this alternative was to lessen or avoid potential noise, visual, and coastal impacts. These three issues are discussed below.

- Noise: As identified in **Alternatives Table 1** and discussed in the **NOISE** section of this PSA, no significant construction or operational noise impacts to adjacent receptors (including both residential and biological resources) have been identified that could not be mitigated. With implementation of proposed Noise conditions of certification related to construction noise of the HBEP, staff has determined the HBEP would be in compliance with all applicable noise performance standards and thresholds and result in less than significant impacts. Even if the HBEP on-site facilities were configured differently, similar temporary construction noise impacts would occur because identical construction would happen, only at slightly different locations within the HBEP site boundary. Furthermore, construction staging and delivery of equipment would be similar or identical to the HBEP. With respect to operational noise, as required by Condition of Certification **NOISE-4**, when the project becomes operational, a noise survey would be conducted to ensure that the project would not exceed applicable city of Huntington Beach noise limits. Any site reconfiguration would require an identical measure. Noise staff has reviewed the proposed HBEP and concluded that reconfiguring the site layout would not significantly lessen or avoid any operational noise impacts.

- Visual Resources: Because of the visual prominence of the air cooled condensers, on-site buildings containing turbines and other components for each power block, an alternative that would involve reconfiguring the site was considered as a means to lessen the visual impacts of the HBEP. The proposed HBEP facilities would occupy a large percentage of the total site area, which would likely limit options to reconfigure the site. Given the high visibility of the project site overall, moving the visually prominent structures within the site would not reduce their visibility from sensitive viewpoints to any great extent. Visual Resources staff has proposed conditions of certification to reduce visual resources impacts of the HBEP. The potential for the proposed HBEP to achieve compliance with several applicable laws, ordinances, regulations, and standards addressing protection of visual resources remains undetermined and will be concluded in the FSA. Visual Resources staff has reviewed the proposed HBEP layout and concluded that reconfiguring the site layout would not significantly lessen or avoid visual impacts.

- Coastal Resources: In the PSA, staff in each resource area has evaluated potential impacts on coastal resources. Based on the location of the HBEP near the coastline, any potentially feasible alternative site configuration would need to lessen impacts on important coastal resources and sensitive viewer groups and uses. The primary impacts on these coastal resources are described in the **NOISE** and **VISUAL RESOURCES** sections of this staff assessment. As discussed above, **NOISE** and **VISUAL RESOURCES** staff concluded that reconfiguring the site layout would not significantly lessen or avoid noise or visual impacts.

If any alternative site configuration was determined to be potentially feasible, it would likely meet most of the basic project objectives. No alternative site configuration is likely to avoid or substantially lessen project impacts identified as significant; therefore, staff has eliminated alternative site configurations from further consideration.

TECHNOLOGY ALTERNATIVES

Technology alternatives to the HBEP were developed and considered by staff to lessen or avoid project impacts. These alternatives are primarily focused on reducing air quality impacts of the HBEP, as discussed below. As such, the following discussion utilizes nomenclature and terminology specific to air quality. For a full description of these terms and issues, please refer to the Air Quality section of this PSA.

Generation Technology Alternatives

The generation technology alternatives evaluated by staff for the HBEP focus on technologies that can utilize natural gas, which can take advantage of the existing natural gas pipeline system and also meet the electrical capacity replacement requirements specified by SCAQMD's Rule 1304. Eligible technologies include combined-cycle technology, other advanced gas turbine(s), or a renewable energy resource.

- Conventional Boiler and Steam Turbine. This technology burns fuel in a conventional boiler to create steam, which is used to drive a steam turbine generator and then is condensed and returned to the boiler. Staff eliminated the conventional boiler and steam turbine technology from consideration because it would not qualify for the SCAQMD Rule 1304 exemption for offsets.

- Simple-Cycle Combustion Turbine. A simple-cycle combustion turbine has a quick startup and rapid ramping capabilities appropriate for a peaking facility. It is also possible to configure HBEP as a simple-cycle peaking facility. The proposed HBEP would have two blocks each consisting of three Mitsubishi Power Systems Americas (MPSA) 501DA combustion turbine generators (CTG), coupled with one steam turbine, and an air cooled condenser in a combined cycle configuration. Instead, the HBEP site could also be configured to contain 9 LMS100 simple-cycle combustion turbines producing about 956 MW, which is similar to CPV Sentinel, an 850-megawatt (MW) peaking facility recently approved by the Energy Commission. Each turbine can have an exhaust stack 13.5 feet in diameter and 90 feet tall. Auxiliary equipment may include a spray mist fogging system for cooling the inlet combustion air; a turbine intercooler; nine single-cell cooling towers, each with circulating water pumps. The size of each cooling tower can be 40 feet high, 42 feet wide and 42 feet long. While feasible and able to achieve most of the HBEP objectives, this alternative was eliminated from detailed consideration as it would not reduce or avoid any HBEP impacts, as discussed below.

    - *Air Quality*: Compared to a combined-cycle facility such as the proposed HBEP, simple-cycle turbines can achieve similar thermal efficiency. For example, the CPV Sentinel project has a net heat rate of 8,468 Btu/kWh under normal operation conditions with a full load efficiency of approximately 42% while the operating range of HBEP is estimated to be 8,800 to 8,140 Btu/kWh with efficiencies ranging from 38.8% to 41.9%. The criteria pollution emissions at this efficiency range are also similar. In addition, the advanced simple-cycle combustion turbine, such as LMS100, would also qualify for the ERC and offset exemption allowed in SCAQMD Rule 1304.

    - *Biological Resources*: Construction impacts to biological resources would likely be similar to HBEP. The primary significant impacts associated with operation of the proposed HBEP would be noise impacts to sensitive adjacent wildlife and habitats, avian collisions and electrocution, and degradation of adjacent habitats from storm water runoff. All of these impacts can be reduced to a less-than-significant level through implementation of staff’s proposed conditions of certification. Impacts from storm water runoff would likely be comparable to the HBEP. This alternative is not expected to avoid any of the proposed project’s impacts to biological resources, and even if some impacts are decreased in magnitude, staff’s proposed conditions of certification for the HBEP would likely still be required to reduce impacts to less than significant.

    - *Land Use*: The simple-cycle combustion turbine scenario would be similar to the proposed HBEP in that both scenarios would replace the existing Huntington Beach Generation Station (HBGS), requiring the issuance of a conditional use permit and a coastal development permit by the city of Huntington Beach, but for the Energy Commission’s exclusive authority to license the project. The simple-cycle combustion turbine scenario would differ compared to the proposed HBEP by not requiring the approval of a variance because if the equipment is similar to the CPV Sentinel project, then the only structure that would exceed the maximum height limit of 50 feet[1] in the Public-Semipublic (PS) zoning district would be the 90 foot stacks (LW2008a). An exception to the height limits for the stack heights could be granted as part of the conditional use permit if public visual resources are preserved and enhanced where feasible. Compliance with all other development standards of the PS district appears to be achievable with this alternative.

- *Noise:* Construction of an industrial facility such as a power plant usually creates temporary or short-term noise impacts. Construction of the proposed combined cycle HBEP, however, would extend beyond what's considered "temporary," but the impacts would be less than significant with the implementation of the staff-proposed noise Conditions of Certification related to construction (see Noise and Vibration section in Part A of this document). The construction period for the simple cycle configuration would be similar to the proposed HBEP since the demolition phases of the existing units would still be needed. Also, construction equipment would be similar. Thus, the noise impacts would be similar.

  Operation of an industrial facility such as a power plant can create permanent or long-term noise impacts. Although different generating equipment would be employed for the simple cycle units, modern power plant equipment, whether for a simple cycle or a combined cycle plant, are acoustically designed per the manufacturer to meet local and state noise standards. Therefore, although the equipment would be different, the overall noise impacts at the project's nearest noise-sensitive receptors, approximately 1,000 feet away, would be similar.

  With implementation of conditions of certification similar to those proposed by staff in the Noise and Vibration section of Part A of this document, the simple cycle alternative would likely create a less-than-significant impact at adjacent noise-sensitive receptors.

- *Visual Resources*: To evaluate the comparative impacts on visual resources for this alternative, staff reviewed the visual analysis in the December 2010 Commission Decision on the CPV Sentinel Energy Project in Riverside County (07-AFC-3), which uses the same technology as the Simple-Cycle Combustion Turbine Alternative being evaluated as an alternative to the proposed HBEP. For the Sentinel Energy Project, the power block structures are configured in a string of eight parallel units across the plant site.

Similar to the Sentinel Energy Project, this alternative would include the following visually prominent structures:

[1] Section 230.72 Exceptions to Height Limits of the Huntington Beach Municipal Code allows for an additional 10 feet exceeding the maximum permitted height in which the site is located for chimneys, vent pipes, cooling towers, and similar structures and necessary mechanical appurtenances. Within the coastal zone exceptions to height limits may be granted only when public visual resources are preserved and enhanced where feasible.

- A total of nine natural gas-fired simple-cycle combustion turbine generators (CTGs), each measuring approximately 130 feet long, 90 feet wide, and 40 feet high.
- Each of the nine CTGs would include an exhaust stack measuring approximately 13.5 feet in diameter and 90 feet high.
- Each of the nine CTGs would include a single-cell cooling tower measuring approximately 42 feet long, 42 feet wide, and 41 feet high.
- A raw water storage tank measuring approximately 110 feet in diameter and 64 feet high.
- A total of two treated water storage tanks measuring 70 feet in diameter and 36 feet high.
- Several steel monopole transmission structures measuring 85–115 feet tall.

By comparison, the proposed HBEP would involve construction of two power blocks, each with three HRSGs and stacks that would be 92 feet tall and 120 feet tall, respectively. The two ACC units would measure approximately 209 feet long, 127 feet wide, and 104 feet high. Other major structures would range from approximately 25 to 40 feet high. The steel monopole transmission structures would be similar to those constructed at the Sentinel Energy Project site.

The two power blocks for the proposed HBEP would group the tallest structures at the project site in two areas at opposite sides of the site. The major project structures for the Simple-Cycle Combustion Turbine Alternative would likely be arranged in a way that could increase the visual breadth of the project compared to the proposed HBEP. The visual effect of this alternative compared to the proposed project could be somewhat greater due to the probable increased clutter and density of power plant structures across the site. The reduced vertical profile of this alternative could slightly improve the effectiveness of measures to visually screen and enhance the project site in accordance with the applicable provisions of the California Coastal Act, but without a site arrangement plan or preliminary concept for screening this alternative, it is unknown how visual screening measures would compare in their potential to reduce impacts.

The potential exists for visible plumes to form over the nine cooling towers. Given the coastal location of the Huntington Beach power plant, it is assumed that plume abated cooling towers would be required for this alternative. Visible plume abatement could be achieved with a wet/dry tower to mix unsaturated hot air with saturated hot air to create an unsaturated exhaust. Wet/dry cooling towers would significantly lower the potential for visible plume formation, but depending on the design and ambient conditions at the site, visible plumes could still form above the cooling towers. Implementation of mitigation measures could be required to reduce the potential size and frequency of visible plume formation to less than significant.

Staff’s visual resources analysis for the proposed HBEP identifies significant impacts from constructing and operating the proposed HBEP that also apply to the Simple-Cycle Combustion Turbine Alternative. The overall impacts on visual resources under this alternative would be similar to HBEP.

ALTERNATIVES EVALUATED IN FULL DETAIL

Based on the analysis provided above in the subsection “Alternatives Eliminated from Detailed Consideration,” the only alternative carried forward for detailed analysis and comparison against the HBEP is the No-Project Alternative. The environmental analysis discussions provided below compare the environmental effects of the No-Project Alternative to the HBEP. A brief description of the No-Project Alternative is provided. Following this overview, an environmental impact analysis is provided for the No-Project Alternative in detail. Where applicable, the analysis is focused on the No-Project Alternative’s ability to avoid or lessen any significant HBEP impacts.

As shown in **Alternatives Table 1**, the HBEP results in potentially significant unavoidable Visual Resources impacts (at Key Observation Points 4 and 5). Pursuant to CEQA, when developing alternatives and evaluating them, all significant project impacts were considered and evaluated for each alternative’s ability to lessen or avoid any HBEP-related impacts.

Alternatives Table 1
Comparison of HBEP and Alternatives

Issue Area	HBEP1	No-Project Alternative2	
		Air Cooled Condenser Retrofit	Wet Cooling Retrofit
Air Quality			
Construction-related emissions	SM	Less Than HBEP	Less Than HBEP
Project operations emissions	SM	Less Than HBEP	Less Than HBEP
Biological Resources			
Construction			
Native vegetation	LS	Similar to HBEP	Greater than HBEP
Common wildlife	SM	Similar to HBEP	Greater than HBEP
Special-status plants	SM	Similar to HBEP	Greater than HBEP
Special-status wildlife	Noise: SM Lighting, Weeds, Stormwater, Groundwater: SM	Noise: Less than HBEP Lighting, Weeds, Stormwater, Groundwater: Similar to HBEP	Noise: Less than HBEP Lighting, Weeds, Stormwater, Groundwater: Similar to HBEP
Jurisdictional wetlands and waters	SM	Similar to HBEP	Greater than HBEP
Noise	SM	Less than HBEP	Less than HBEP
Lighting	SM	Similar to HBEP	Similar to HBEP
Dust	SM	Similar to HBEP	Similar to HBEP
Invasive weeds	SM	Similar to HBEP	Similar to HBEP
Stormwater runoff	SM	Similar to HBEP	Similar to HBEP
Groundwater contamination	SM	Similar to HBEP	Similar to HBEP
Operation			
Noise	At marshes: LS At Wildlife Care Center: LS	Less than HBEP	Less than HBEP
Lighting	LS	Similar to HBEP	Similar to HBEP
Avian collision and electrocution	SM	Similar to HBEP	Similar to HBEP
Stormwater runoff	SM	Similar to HBEP	Similar to HBEP
Nitrogen deposition	LS	Less than HBEP	Less than HBEP

Cultural Resources			
Potential impacts from construction: archaeological resources	PSM	Similar to HBEP	Similar to HBEP
Potential impacts from construction: ethnographic resources	—	Similar to HBEP	Similar to HBEP
Potential impacts from construction: built environment resources	LS	Similar to HBEP	Greater than HBEP
Potential impacts from operation: archaeological resources	LS	Similar to HBEP	Similar to HBEP
Potential impacts from construction: ethnographic resources	—	Similar to HBEP	Similar to HBEP
Potential impacts from operation: built environment resources	—	Similar to HBEP	Similar to HBEP
Geology and Paleontology			
Risk of strong seismic shaking	PSM	Similar to HBEP	Similar to HBEP
Risk of liquefaction resulting from strong seismic shaking.	PSM	Similar to HBEP	Similar to HBEP
Risk of potential excessive settlement due to dynamic compaction resulting from strong seismic shaking.	PSM	Similar to HBEP	Similar to HBEP
Risk of inundation by tsunami resulting from distant underwater earthquake of local submarine landslide	LS	Similar to HBEP	Similar to HBEP
Hazardous Materials			
Risk of fire or explosion impact off-site resulting from natural gas usage during operations	PSM	Similar to HBEP	Similar to HBEP
Risk of hazardous material spill impact en route (off-site) resulting from hazardous materials transportation to site	PSM	Similar to HBEP	Similar to HBEP
Risk of hazardous material spill / migration impact off-site resulting from hazardous materials storage and use on-site shaking	PSM	Similar to HBEP	Similar to HBEP
Risk of significant drawdown of emergency response services causing impact off-site	LS	Similar to HBEP	Similar to HBEP
Land Use			
Exceed maximum allowable height limit of Public Semi-Public zoning district.	PSM	Similar to HBEP	Similar to HBEP
Noise and Vibration			
Construction	LS	Less Than HBEP	Less Than HBEP
Operation	LS	Greater than HBEP	Greater than HBEP
Public Health			
Construction-related diesel particulate matter emissions	LS	Less Than HBEP	Less Than HBEP
Operation-related toxic air contaminants/emissions	LS	Less Than HBEP	Less Than HBEP
Operation-related Legionella	—	Same as HBEP	Less Than HBEP
Socioeconomics			
Environmental justice population within six-mile buffer.	No	No	No
Induce substantial population growth in	LS	Slightly less than	Less than HBEP

an area, either directly or indirectly		HBEP	
Displace substantial numbers of people and/or existing housing, necessitating the construction of replacement housing elsewhere	LS	Slightly less than HBEP	Less than HBEP
Adversely impact acceptable levels of service for police protection, schools, and parks and recreation.	LS	Slightly less than HBEP	Less than HBEP
Increased property taxes, construction and operation employment income, and increased state and local taxes and fees	B	Slightly less than HBEP	Less than HBEP
Soil and Water Resources			
Soil erosion by wind and water or water quality impacts during project construction	PSM	Similar to HBEP	Similar to HBEP
Soil erosion by wind and water or water quality impacts during project operation	PSM	Similar to HBEP	Similar to HBEP
Water quality impacts from power plant operations	B	Similar to HBEP	Similar to HBEP
Water quality impacts from sanitary waste	—	Same as HBEP	Same as HBEP
Potential impacts from on-site and off-site flooding	—	Same as HBEP	Same as HBEP
Potential to impede or redirect 100-year flood flows, as shown on Federal Emergency Management Agency maps	—	Same as HBEP	Same as HBEP
Water Supply			
Potential impacts on local wells	B	Similar to HBEP	Similar to HBEP
Potential impacts on local water supply	B	Similar to HBEP	Similar to HBEP
Traffic & Transportation			
Cause an increase in traffic	LS	Less than HBEP	Greater than HBEP
Conflict with an applicable plan, ordinance or policy establishing measures of effectiveness for the performance of the circulation system	LS	Less than HBEP	Greater than HBEP
Conflict with an applicable congestion management program	LS	Less than HBEP	Greater than HBEP
Substantially increase hazards	-	Less than HBEP	Greater than HBEP
Result in inadequate emergency access	-	Less than HBEP	Greater than HBEP
Conflict with adopted policies, plans, or programs regarding alternative transportation	-	Similar to HBEP	Similar to HBEP
Result in a change in air traffic safety risk (stacks)	LS	Similar to HBEP	Similar to HBEP
Produce a thermal plume in an area where flight paths are expected to occur below 1,000 feet from the ground	PSM	Similar to HBEP	Similar to HBEP
Result in cumulative traffic effects	LS	Less than HBEP	Less than HBEP
Transmission Line Safety and Nuisance			
Impacts from generated fields	LS	Less than HBEP	Less than HBEP
Nonfield impacts from operations	LS	Less than HBEP	Less than HBEP
Visual Resources			
Impact at key observation point (KOP) 4	PSU	Similar to HBEP	Less than HBEP
Impact at KOP 5	PSU	Less than HBEP	Less than HBEP
Construction-related effects	SM	Less than HBEP	Less than HBEP
Project construction lighting	SM	Less than HBEP	Less than HBEP
Project operations lighting	SM	Similar to HBEP	Similar to HBEP

Potential daytime glint or glare from project structures	SM	Similar to HBEP	Similar to HBEP
Waste Management			
Potential for Material/waste generated during the construction and operation to not be managed in an environmentally safe manner, i.e. recycling or disposal	PSM	Similar to HBEP	Similar to HBEP
Potential for disposal or diversion of project materials to cause impacts on existing waste disposal or diversion facilities	PSM	Less than HBEP	Similar to HBEP
Potential for impacts on human health and the environment related to past or present soil or water contamination	PSM	Similar to HBEP	Similar to HBEP
Worker Safety & Fire Protection			
Risk of fire or explosion impact off-site resulting from natural gas usage during construction	PSM	Similar to HBEP	Similar to HBEP
Risk of significant drawdown of emergency response services causing impact off-site	LS	Similar to HBEP	Similar to HBEP
Notes: 1 The following correspond to impact determinations of the HBEP, as provided within each environmental analysis section of this PSA: — = no impact UNK = significance of impact is unknown B = beneficial impact LS = less than significant impact, no mitigation required SM or PSM = significant or potentially significant impact that can be mitigated to less than significant SU or PSU = significant and unavoidable or potentially significant and unavoidable impact that cannot be mitigated to less than significant 2 This summary is comparative in nature, and corresponds to impact of the Alternative when compared to the HBEP, as discussed within subsection "Alternatives Evaluated in Detail."			

NO PROJECT (RETROFIT) ALTERNATIVE

This analysis evaluates the No-Project Alternative to the HBEP to fulfill the requirements of CEQA §15126. As discussed in the subsection "Energy Commission Screening Process," the Energy Commission evaluates the impacts of not constructing a project to determine whether a No-Project Alternative is superior to the project (a CEQA requirement that the option of not building the project must be analyzed and compared to the project). However, alternatives staff has considered and researched the likelihood of the HBGS being retired absent the HBEP and found it unlikely. Therefore, alternatives staff believes the No-Project Alternative would entail the existing HBGS being retrofitted to be compliant with SWQCB's OTC policy to allow for continued operation. This alternative is described and analyzed below.

Background

Under a No-Project Alternative scenario, the HBGS would need to employ some other means to comply with the SWRCB's OTC Policy to keep the facility online. Currently, HBGS Units 1 and 2 are used for electrical production, while Units 3 and 4 are used as synchronized condensers providing voltage support to the electrical grid. This alternative would retrofit HBGS Units 1 and 2 to cease the use of ocean water for cooling and use either an air cooled condenser or wet cooling using water from another source. For the wet cooling retrofit scenario, the following water sources have been eliminated from consideration by staff:

- Continued Use of Ocean Water to Meet OTC Policy (90% improvement in impingement and entrainment). The applicant briefly identified a No-Project Alternative retrofit scenario utilizing seawater as a water source (HBEP 2012a, p. 6-4). Staff does not consider use of seawater for cooling as a viable alternative because one of the main objectives of the HBEP is compliance with SWRCB's policy to eliminate use of seawater. Staff considers continued use of seawater infeasible and is therefore eliminated from further consideration.
- Use of Potable Water to Meet OTC Policy. The applicant identified a No-Project Alternative retrofit scenario utilizing a potable water source (HBEP 2012a, p. 6-4). Wet cooling, using fresh or potable water, is discouraged by SWRCB and Energy Commission policies related to water consumption of a facility. While the HBEP would utilize potable water for industrial processes (e.g., evaporative cooling blowdown makeup) and no significant impacts have been identified from this use, staff has eliminated the use of fresh or potable water as a retrofit option for cooling from further consideration to comply with SWRCB and Energy Commission policies and because it would require substantially more water than HBEP.

No Project (Retrofit) Alternative Scenarios

The following identifies the two possible No-Project Alternative retrofit scenarios considered feasible by staff for complying with the SWRCB's OTC policy:

- Retrofit Air Cooled Condenser Scenario: This scenario would continue operation of HBGS Units 1 and 2 (430MW) as steam boilers and Units 3 and 4 as synchronized condensers with the requirement that HBGS Units 1 and 2 be retrofitted with an air-cooled condenser. The retrofit activities would involve reconfiguring the existing plant and installing air-cooling infrastructure similar to that of the HBEP, but at HBGS Units 1 and 2 only. Engineering staff estimate the retrofit air cooled condenser used with HBGS Units 1 and 2 would be about 43% larger than what is proposed for HBEP, but could fit where the HBEP generating block 1 is being proposed (refer to Project Description).

  Under this retrofit scenario, the generating station would operate slightly less efficiently than the proposed HBEP, the existing HBGS, and the No-Project Alternative wet cooled scenario for the following reasons:

  - Retrofitting the existing boilers for air-cooling is not as efficient as the proposed HBEP system; and
  - Wet cooling is inherently more efficient than dry cooling.
- Wet Cooling Scenario: This scenario would continue operation of HBGS Units 1 and 2 (430MW) as steam boilers and Units 3 and 4 as synchronized condensers. However, this alternative would require operation of HBGS Units 1 and 2 to use a new non-seawater source for cooling water. Descriptions of the activities and components necessary for this retrofit scenario are provided below (HBEP 2013ii).

- *Recycled Water Source*: This scenario would use recycled water for the makeup cooling water source. Such water is currently not delivered to the existing HBGS site. Recycled water is potentially available to the HBGS from a combination of the following two Orange County Sanitation District's (OCSD) facilities (assumed to be an adequate long-term reliable recycled water source), which are connected by an interplant pipeline:
  - OCSD Huntington Beach Plant #1 is located 2.5 miles northeast of the HBEP site at the intersection of Ellis Avenue and Ward Street. A portion of the secondary water flow from OCSD Plant #1 goes to the Orange County Water District (OCWD) for use in the District's groundwater replenishment program.
  - OCSD Huntington Beach Plant #2 is located 1.1 miles east-southeast of the HBEP site, south of Hamilton Avenue between Brookhurst Street and the adjacent Santa Ana River. OCSD Plant #2 is closer to the HBGS and all secondary effluent is currently discharged to the ocean. Feasibly, this alternative could utilize only this Plant #2 secondary effluent discharge (per pipeline route 2 identified below).
- *Recycled Water Pipeline*: Delivery of recycled water from these two OCSD facilities would require construction of a pipeline to the HBGS site. The following two pipeline options are available:
  - There is currently an interplant pipeline located along the Santa Ana River that connects OCSD Plants #1 and to #2 to each other. The OCSD interplant pipeline could potentially be tapped at Hamilton Avenue to minimize the pipeline route. A new 1.9-mile pipeline could be constructed along Hamilton Avenue to Newland Street, and along Newland Street to the HBGS site to deliver secondary effluent water.
  - A new 2.8-mile pipeline for secondary treated effluent directly from OCSD Plant #2 could also be constructed and routed along the Santa Ana River to Hamilton Avenue to Newland Street to the HBGS site; however, this route may require the water to be pumped from OSCD Plant #2 to Hamilton Avenue.
- *Required Water Treatment Facility*: Treatment of the recycled water from OCSD to Title 22 tertiary standards would be required prior to use in the wet cooling tower system. Therefore, a water treatment facility would be constructed at the existing HBGS. The footprint for the treatment facility, based on water need for 430 MW is approximately 13,000 square feet; the height is approximately 23 feet, based on a five million gallon per day (MGD) facility that would include filtration and disinfection. There would be an equalization/storage tank to ensure an adequate supply of tertiary treated water to meet peak demands of this No-Project Alternative scenario at HBGS. This is not included in the footprint estimate. It is assumed the equalization/storage tank could, however, be combined with the chlorine contact tank to optimize the overall footprint.

  For the purposes of this No-Project Alternative scenario, it is assumed the necessary tertiary water treatment facility would be sited within the HBGS. This is to ensure the feasibility of both pipeline route alternatives by having the treatment facility downstream at HBGS. The feasible available location for a water treatment facility is within the central portion of the HBGS site, southeast of the on-site SCE switchyard. Construction of a water treatment facility at this location would require the demolition of various support building and facilities.

- *Construction of a New On-Site Cooling Tower:* To utilize this new wet cooling technology for HBGS Units 1 and 2, a wet cooling tower would be required at HBGS. An initial estimate indicates the wet cooling tower would have approximate dimensions of 60 feet wide by 650 feet long (approximately 38,880 square feet) and 50 feet high. Given the coastal location of HBGS, it is assumed a plume-abated cooling tower would also be required. The size of this cooling tower is currently unknown to staff. The only available location for these cooling towers is within the central portion of the HBGS site, southeast of the on-site SCE switchyard. Construction of the wet cooling towers at this location would result in the demolition of various support building and facilities.

In terms of operational efficiency, under this retrofit scenario (i.e., wet cooling), the generating station would operate slightly less efficiently than the proposed HBEP and the No-Project Alternative air cooled scenario, and similar to the existing HBGS.

No Project (Retrofit) Alternatives Consistency with HBEP Objectives

Alternatives Table 2 provides a summary of each No-Project Alternative scenario's ability to fulfill the HBEP objectives, in particular, relating to flexible generation. As shown in **Alternatives Table 2**, the No-Project Alternative would be consistent with half of the HBEP objectives.

Alternatives Table 2
Summary Comparison of No-Project Alternative Scenarios to HBEP Objectives

HBEP Objective	No-Project Alternative – Dry Cooling Retrofit Scenario	No-Project Alternative – Wet Cooling Retrofit Scenario
Provide efficient, reliable and predictable power supply by using combined-cycle, natural gas-fired combustion turbines to replace the OTC generation.	No. Under the No-Project Alternative, improvements to the existing HBGS would be made to comply with SWRCB's OTC Policy. However, the retrofit designs associated with the No-Project Alternative are not found to be the most efficient, reliable, or predictable use of the existing HBGS. Furthermore, Engineering staff finds that retrofitting the existing boilers for air-cooling is not as efficient as the proposed HBEP system.	No. Under the No-Project Alternative, improvements to the existing HBGS would be made to comply with SWRCB's OTC Policy. However, Engineering staff finds that installation of wet cooling towers would slightly decrease the existing HBGS's efficiency and increase particulate matter (PM) emissions when compared to the HBEP.
Support the local capacity requirements of Southern California's Western Los Angeles Basin.	Partially. While this retrofit scenario would allow for the HBGS to continue producing 436 MW of electricity in a similar operational capacity it currently provides, this alternative would	Partially. While this retrofit scenario would allow for the HBGS to continue producing 436 MW of electricity in a similar operational capacity it currently provides, this alternative would

	not provide as much generation to the CAISO Western Los Angeles Local Reliability Subarea as the HBEP (939 MW).	not provide as much generation to the CAISO Western Los Angeles Local Reliability Subarea as the HBEP (939 MW).
Develop a 939 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.	No. This retrofit scenario would only allow for the HBGS to continue producing 436 MW of electricity in a similar operational capacity it currently provides, which does not allow fast ramping or fast starting capability. Furthermore, Engineering staff finds that retrofitting the existing boilers for air-cooling is not as efficient as the proposed HBEP system.	No. This retrofit scenario would only allow for the HBGS to continue producing 436 MW of electricity in a similar operational capacity it currently provides, which does not allow fast ramping or fast starting capability. Furthermore, Engineering staff finds that installation of wet cooling towers would slightly decrease the existing HBGS's efficiency when compared to the HBEP.
Reuse existing electrical, water, wastewater, and natural gas infrastructures and land to minimize terrestrial resource and environmental justice impacts by developing on an existing brown field site.	Yes. Under this No-Project Alternative retrofit scenario, improvements to the existing HBGS would be made to comply with SWRCB's OTC Policy. These improvements would utilize the existing electrical, water, wastewater, and natural gas infrastructures and land serving the HBGS.	Partially. Under this No-Project Alternative retrofit scenario, improvements to the existing HBGS would be made to comply with SWRCB's OTC Policy. These improvements would utilize the existing electrical, water, wastewater, and natural gas infrastructures and land serving the HBGS. A new pipeline would be required to deliver water to the site.
Site the project to serve the load area without constructing new transmission facilities.	Yes. Under this No-Project Alternative retrofit scenario, improvements to the existing HBGS would be made to comply with SWRCB's OTC Policy. These improvements would utilize the existing transmission infrastructure serving the HBGS. However, this retrofit scenario would only allow for the HBGS to continue producing 436 MW of electricity in a similar operational capacity it currently provides to the CAISO Western Los Angeles Local Reliability Subarea.	Yes. Under this No-Project Alternative retrofit scenario, improvements to the existing HBGS would be made to comply with SWRCB's OTC Policy. These improvements would utilize the existing transmission infrastructure serving the HBGS. However, this retrofit scenario would only allow for the HBGS to continue producing 436 MW of electricity in a similar operational capacity it currently provides to the CAISO Western Los Angeles Local Reliability Subarea.
Site the project on property that has industrial land use designation with consistent zoning.	Yes. Under the No-Project Alternative, improvements to the existing HBGS would be made to comply with SWQCB's OTC Policy. These improvements would be made to the existing HBGS, which is currently designated and zoned as an electrical generation industrial facility.	Yes. Under the No-Project Alternative, improvements to the existing HBGS would be made to comply with SWQCB's OTC Policy. These improvements would be made to the existing HBGS, which is currently designated and zoned as an electrical generation industrial facility.

Environmental Analysis

Alternatives Table 1 provides a summary comparison of the HBEP environmental impacts and those of the No-Project Alternative retrofit scenarios. Based upon staff's analysis, the No-Project Alternative retrofit scenarios impacts are similar to or less than those of the HBEP. The following discussion provides a detailed issue area analysis of the No-Project Alternative retrofit scenarios.

Air Quality

Background

The installation of wet cooling towers would decrease the efficiency of Units 1 and 2 as well as increase their particulate matter (PM) emissions. Similar to wet cooling technology, use of an air-cooled condenser to cool these two units would also decrease their efficiency. In addition, installation of an air-cooled condenser may require more site space, auxiliary loads, and capital cost than retrofitting with wet cooling towers. Units 3 and 4 would continue to be operated as synchronous condensers. These units do not cause any onsite air pollutant emissions, although they would consume small amounts of electricity to keep them spinning.

When comparing air quality emission impacts of the No-Project Alternative retrofit scenarios against the HBEP, Air Quality staff assumes that under either alternative, Units 1 and 2 would continue to operate, but would be cooled with either an air-cooled condenser or a wet cooling tower. Under either alternative staff assumes that these two units would have annual usage rates similar to what they had during last two years. In 2011, Unit 1 operated for 1,205 hours and Unit 2 operated for 1,300 hours. In 2012, Unit 1 operated for 1,153 hours and Unit 2 operated for 2,496 hours (Air Quality staff derived from QFER CEC-1304 Power Plant Owner Reporting Database). By comparison, HBEP is expected to operate for 6,835 hours per year.

Retrofit Air Cooled Condenser Scenario

To compare emissions, air quality staff reviewed the HBGS emission data in the SCAQMD Annual Emission Reporting Program and compared emissions for Units 1 and 2 to estimated emissions for the proposed HBEP. Air Quality staff has determined the proposed HBEP would have much higher emissions than the No-Project Alternative air cooled retrofit scenario because the HBEP would have more generators operating more hours in any given day/week/year. The No-Project Alternative air cooled retrofit scenario would only continue operation of existing HGBS Units 1 and 2. Therefore, the decrease in pollutant emissions under the No-Project Alternative air cooled retrofit scenario is due to a decrease in operational hours when compared to the HBEP. Therefore, the No-Project Alternative air cooled retrofit scenario would be less than those of the proposed HBEP. Regardless, emissions from both scenarios would be mitigated to a level of less than significant.

Retrofit Wet Cooling Scenario

To compare emissions, air quality staff reviewed the HBGS emission data in SCAQMD's Annual Emission Reporting Program and compared emissions for Units 1 and 2 to estimated emissions for the proposed HBEP. Air Quality staff has determined the proposed HBEP would have much higher emissions than the No-Project Alternative wet cooled retrofit scenario the HBEP would have more generators operating more hours in any given day/week/year. The No-Project Alternative wet cooled retrofit scenario would only continue operation of existing HGBS Units 1 and 2. The decrease in pollutant emissions under the No-Project Alternative wet cooled retrofit scenario is due to a decrease in operational hours when compared to the HBEP. Therefore, the No-Project Alternative wet cooled retrofit scenario would be less than those of the proposed HBEP. Regardless, emissions from both scenarios would be mitigated to a level of less than significant.

Biological Resources

Retrofit Air Cooled Condenser Scenario

This No-Project Alternative scenario would be constructed within previously disturbed areas. Therefore, construction impacts would be mostly similar to those of the proposed project. However, noise impacts to sensitive wildlife from the air cooled condenser retrofit scenario of the No-Project Alternative are expected to be less than the proposed HBEP because the construction duration would be substantially shorter.

Retrofit Wet Cooling Scenario with Recycled Water

This No-Project Alternative scenario would be constructed in previously disturbed areas with the exception of a water pipeline that would be routed along the Santa Ana River. The Santa Ana River and proximate floodplain support native riparian vegetation, including southern cottonwood willow riparian forest, which is a sensitive vegetation community as designated by the California Department of Fish and Wildlife (CDFW 2013). The river and adjacent habitat also potentially support special-status plants and wildlife (CDFW 2013) and are designated jurisdictional waters of the U.S and/or state. Ground disturbance along the Santa Ana River during construction of the pipeline would result in greater impacts to native vegetation, common wildlife, special-status plants, and jurisdictional wetlands and waters than the proposed project. However, noise impacts to sensitive wildlife would be less than the proposed project because the construction duration would be substantially shorter.

Cultural Resources

Background

Changes to the cooling system and other facilities as described above could result in substantial adverse impacts to the HBGS, which is listed on a local register of historic resources and therefore might qualify as a historical resource for the purposes of the CEQA §15064.5[a][2]. Potential impacts on the HBGS would stem from modification of the existing structures as well as demolition of the facilities associated with construction of the retrofit dry and wet-cooling technologies. However, as noted in the **Cultural Resources** section of this PSA, recent re-evaluation and survey of the HBGS (Galvin2012) found the resource to be ineligible for listing at any level: local, California Register of Historical Resources (CRHR) or National Register of Historic Properties (NRHP). Based on the preponderance of evidence that the Edison Plant is not a historical resource under CEQA, staff will recommend in the FSA that the Committee/Commission make a determination of ineligibility.

Retrofit Air Cooled Condenser Scenario

This scenario involves upgrades to equipment at HBGS Units 1 and 2, construction of an air cooled condenser tower in the vicinity of the proposed HBEP Block 1, and installation of pipelines between the condenser tower and HBGS Units 1 and 2. All such construction would take place within the existing HBGS site and require depths of excavation similar to the proposed HBEP, as analyzed in the Cultural Resources section of this PSA. However, replacing the current cooling system would concentrate the majority of project impacts to machinery already built. Therefore, staff expects that the potential to damage buried archaeological resources or human remains would be reduced from the degree of impact under the HBEP.

On the other hand, changes to the cooling system could result in a substantial adverse change (as defined at 14 Calif. Code Regs., §15064.5[b]) to the HBGS, which is listed on a local register of historic resources and therefore might qualify as a historical resource for the purposes of CEQA §15064.5[a][2]. Potential impacts on the HBGS would stem from modification of the existing equipment as well as demolition of the East Fuel Oil Tank, Distillate Storage Tank, and perhaps the facilities associated with the Peaker to accommodate construction of the new condenser tower. As noted in the Supplemental Focused Analysis (CEC 2013X), recent re-evaluation and survey of the HBGS (Cardenas et al. 2012; Galvin 2012) found the resource to be ineligible for listing at any level: local, CRHR or NRHP. Based on the preponderance of evidence that the Edison Plant is not a historical resource under CEQA, staff will recommend in the FSA that the Committee/Commission make a determination of ineligibility. Staff concludes that the impacts of this retrofit scenario would be less than those of the proposed project since the HBEP calls for demolition of the HBGS, rather than this scenario's retrofit of one system.

Retrofit Wet Cooling Scenario with Recycled Water

Construction of the on-site portion of recycled water pipeline, water treatment facility, and cooling tower would take place on the existing project site and would require depths of excavation similar to the proposed project, as analyzed in the Cultural Resources section of this PSA. Staff expects that potential impacts on buried archaeological resources of this retrofit scenario would be similar to those of the proposed HBEP. The wet cooling scenario would add a recycled water pipeline along one of two potential, off-site routes, which would not be required for the HBEP as proposed. The applicant's records search for the proposed HBEP covers approximately 80% of pipeline route option 1 and 50–60% of pipeline route option 2 (AES 2012a: Appendix 5.3C).

The records search results indicate that at least eight previous cultural resource studies have been conducted along the proposed pipeline routes (Ahlering 1973; Bonner 2007; Brown and Maxon 2010; Demcak 1999; Duke 2000; Hoover 2000; Lapin 2000; Mason and Chandler 2003). One previously recorded cultural resource is located in or adjacent to the proposed pipeline routes: P-30-1531 (AES 2012a: 5.3-16; Cardenas et al. 2012:4-2; Duke 1999, 2000). P-30-1531 is a natural shell midden that was originally recorded as a prehistoric shell midden (a type of archaeological site). The shell midden was later determined to be natural in origin and recommended as ineligible for listing in the California Register of Historical Resources (Duke 2000:4). Therefore, staff does not consider P-30-1531 to be a historical resource or unique archaeological resource, as defined by CEQA §15064.5[a] and Public Resources Code §§5024.1 and 21083.2[g].

Communication between staff and the applicant includes a general description of pipeline routes to either of the two OCSD locations (HBEP 2013ii). As noted above, Cultural Resources staff has results for only a portion of either of the potential routes. Because the entire route has not been surveyed, staff does not have specific information about other cultural resources that might be impacted by the construction of one of the two pipelines. Addition of one of two potential pipeline routes could add to the potential impacts of the proposed project; therefore, the Retrofit Cooling Scenario could result in greater impacts on cultural resources compared to the HBEP.

Geology and Paleontology

Retrofit Air Cooled Condenser Scenario

There are no geologic resources that would be impacted in the areas where the air cooled condenser would be constructed. This facility can also be designed and constructed such that geologic hazards are not a concern similar to HBEP. Paleontological resources may be encountered in excavations that exceed 11 feet, but impacts can be mitigated similar to the HBEP. Thus, impacts to or from this No-Project Alternative scenario would be similar to the proposed HBEP.

Retrofit Wet Cooling Scenario Using Recycled Water

This scenario would continue operation of HBGS Units 1 and 2 (430 MW) as steam boilers and Units 3 and 4 as synchronized condensers. However, this Alternative would require operation of HBGS Units 1 and 2 to utilize a new non-seawater water source for power plant cooling. The only feasible source of non-sea water for power plant cooling is non potable recycled waste water. The recycled wastewater would be generated at the Orange County Sanitation District Plant #2 and piped to HBEP. This No Project Alternative would require construction of a pipeline from the wastewater treatment facility, construction of a new on site water treatment facility, and construction of a new cooling tower. The pipelines would be constructed in a developed area that has already largely been disturbed. The alignment of the recycled water pipeline traverses potentially active traces of the Newport-Inglewood fault. Should surface rupture occur along those traces of the potentially active fault, the conveyance of recycled water to the HBEP would be disrupted. Without an adequate source of cooling water, the operation of the power plant may be jeopardized. The net effect to the Recycled Water Alternative from surface fault rupture would be greater than the proposed HBEP, unless the existing potable water supply is maintained as a backup supply. All other seismic related impacts would be the same as the proposed HBEP.

There are no geologic or mineralogic resources that would be impacted in the areas where the pipelines, cooling tower, and water treatment facility would be constructed. These facilities can also be designed and constructed such that geologic hazards are not a concern, similar to HBEP. Paleontological resources may be encountered in excavations that exceed 11 feet but impacts can be mitigated similar to the HBEP. Impacts from this No Project alternative would be similar to the proposed HBEP.

Hazardous Materials

Retrofit Air Cooled Condenser Scenario

As the use of hazardous materials at the proposed HBEP would have no significant impacts off-site, there would be no significant impact on the public resulting from their storage and use. The air cooled retrofit alternative would present a nearly identical hazardous materials risk profile as the HBEP. Both would use natural gas as fuel, use ammonia for selective-catalytic reduction of oxides of nitrogen in combustion exhaust, and have a closed-loop cooling water circuit with its associated water quality maintenance chemicals. Impacts from this No-Project Alternative scenario would be similar to those of the proposed HBEP.

Retrofit Wet Cooling Scenario Using Recycled Water

This wet cooling retrofit scenario would also present a nearly identical hazardous materials risk profile as the proposed HBEP. Both would use natural gas a fuel, use ammonia for selective-catalytic reduction of oxides of nitrogen in combustion exhaust, and have a cooling water circuit. In this case, the cooling water circuit passes through an open-to-air cooling tower, and would include some biocides in its maintenance chemistry. Still there would be negligible potential for offsite impact. Impacts from this No-Project Alternative scenario would be similar to those of the proposed HBEP.

Land Use

Retrofit Air Cooled Condenser Scenario

This retrofit scenario would differ compared to the proposed HBEP by continuing the use of the existing HBGS Units 1-4 with 200-foot tall stacks rather than demolishing them to construct the HBEP Blocks 1 and 2 with 120-foot tall stacks, and by installing a 104-foot tall air cooled condenser that would be the same height as the air cooled condenser proposed for HBEP. The HBGS Units 1-4 are legal non-conforming structures which would remain in use and would not be required to be brought into compliance with the 50-foot maximum height limit of the Public-Semipublic (PS) zoning district. The air cooled condenser would be a new structure, which would exceed the maximum allowable height limit of the PS zone. Similar to the HBEP, this alternative would require the approval of a height variance. Compliance with all other development standards of the PS district appears to be achievable with this alternative. Impacts from this No-Project Alternative scenario would be similar to the proposed HBEP.

Retrofit Wet Cooling Scenario Using Recycled Water

The wet cooling scenario would differ compared to the proposed HBEP by continuing the use of the existing HBGS Units 1-4 with 200-foot tall stacks rather than demolishing them to construct the HBEP Blocks 1 and 2 with 120-foot tall stacks, and by constructing a 23-foot tall water treatment facility and a 50-foot tall on-site wet cooling tower. HBGS Units 1-4 are legal non-conforming structures which would remain in use and would not be required to be brought into compliance with the 50-foot maximum height limit of the PS zoning district. The estimated heights of the new water treatment facility and wet cooling tower would be within the 50-foot maximum height limit of the PS district and would not require a height variance, whereas the HBEP would require a height variance for the new power blocks and air cooled condenser. Compliance with all other development standards of the PS district appears to be achievable with this alternative. Impacts from this No-Project Alternative scenario would be similar to the proposed HBEP.

Noise and Vibration

Retrofit Air Cooled Condenser Scenario

Construction of an industrial facility such as a power plant usually creates temporary or short-term noise impacts. Construction of the proposed HBEP, however, would extend beyond what is considered “temporary”, but the impacts would be less than significant with the implementation of the staff-proposed noise conditions of certification related to construction. The construction period for this scenario, however, would not be as extensive as the proposed HBEP because the demolition phases would be greatly reduced.

Operation of an industrial facility such as a power plant can create permanent or long-term noise impacts. The primary noise sources of the proposed HBEP are the power blocks, where the steam turbine generators, air-cooled condensers, and various pumps and fans would be located. The proposed HBEP would employ modern turbines and other machinery which would generate less noise than the boilers of the existing project. Therefore, the noise impact of this No-Project Alternative scenario would be more than the proposed HBEP. However, with implementation of conditions of certification similar to those proposed by staff in the **NOISE and VIBRATION** section of this PSA, the No-Project dry cooling scenario would likely create a less-than-significant impact at adjacent noise-sensitive receptors.

Retrofit Wet Cooling Scenario Using Recycled Water

Construction of this alternative would generate temporary or short-term noise impacts. Construction of this alternative would also include the construction of a recycled water pipeline along public roadways. However, the construction period for this scenario would not be as extensive as the proposed HBEP because the demolition phases would be greatly reduced. Noise impacts would be less than significant with the implementation of the staff-proposed noise conditions of certification related to construction.

The noise impact of this No-Project Alternative scenario would be more than the proposed HBEP as many components of the HBEP would generate less noise than the boilers of the HBGS. However, with implementation of conditions of certification similar to those proposed by staff in the Noise and Vibration section of this PSA, the No-Project wet cooling scenario would likely create a less-than-significant impact at adjacent noise-sensitive receptors.

Public Health

Retrofit Air Cooled Condenser Scenario

The retrofit air cooled condenser scenario overall would have less construction activities when compared to HBEP. Therefore, construction-related diesel particulate matter (DPM) emissions and public health impacts of this retrofit air cooled condenser scenario would be less than the DPM and public health impacts of the proposed HBEP.

Even though the generating station under this retrofit scenario would operate slightly less efficiently than the proposed HBEP, the capacity of the proposed HBEP (939MW) is more than double that of this retrofit scenario (430MW). Staff concludes that the toxic air emissions from project operation under this retrofit scenario would be less than the proposed HBEP. Therefore, during operation, the public health impacts under the retrofit scenario would be less than the proposed HBEP.

Retrofit Wet Cooling Scenario Using Recycled Water

Under the wet cooling scenario, there would be some construction activities (such as the water source pipeline, on-site water treatment facility and on-site cooling tower). However, the construction activities under this wet cooling scenario overall would be less than the proposed HBEP. Therefore, construction-related DPM emissions and public health impacts of this wet cooling scenario would be less than the DPM and public health impacts of the proposed HBEP.

Under this wet cooling scenario, one concern during project operation would be that the potential exists for bacterial growth (i.e., Legionella2) to occur in the cooling system and emissions of toxic air contaminants from cooling tower mist or drift. This public health impact would need to be mitigated to less than significant by applying appropriate condition of certifications. The capacity of the proposed HBEP (939MW) is more than double that of this wet cooling scenario (430MW). Staff concludes that the toxic air emissions from project operation under the wet cooling scenario would be less than the proposed HBEP. Considering that there are adequate mitigation measures available for Legionella and that there would be less toxic air emissions during project operation under the wet cooling scenario, staff concludes that the public health impacts during operation under the wet cooling scenario would be less than the proposed HBEP.

Socioeconomics

Retrofit Air Cooled Condenser Scenario

Retrofitting the existing HBGS to be air cooled would employ a smaller sized construction workforce and have a shorter construction period as the HBEP. Impacts associated with substantial population growth in the project area and the need for new

[2] Legionella is a bacterium that is ubiquitous in natural aquatic environments and is also widely distributed in man-made water systems. It is the principal cause of Legionellosis, also known as Legionnaires' Disease, which is similar to pneumonia. Transmission to people results mainly from inhalation or aspiration of aerosolized contaminated water. Untreated or inadequately treated cooling systems, such as industrial cooling towers and building heating, ventilating, and air conditioning systems, have been correlated with outbreaks of Legionellosis.

housing would be slightly less than the HBEP. This alternative would not be subject to development impact fees (Chapter 17 of the Huntington Beach Municipal Code- Police Facilities and Parkland Acquisition and Park Facilities Development Impact Fees), unlike the HBEP, as this alternative does not propose new buildings. Also, as no demolition and construction activities would occur at the HBGS, development impact fees are not applicable.

Retrofitting activities would generate benefits such as increased property taxes, construction and operation employment income, and increased state and local sales taxes and fees. The economic benefits would be similar to those for the HBEP.

Retrofit Wet Cooling Scenario Using Recycled Water

The size of the construction workforce and length of construction period would be less than the HBEP. Impacts associated with substantial population growth in the project area and the need for new housing would be slightly less than the HBEP. This alternative would not be subject to development impact fees (Chapter 17 of the Huntington Beach Municipal Code- Police Facilities and Parkland Acquisition and Park Facilities Development Impact Fees), unlike the HBEP, as this alternative does not propose new buildings. Also, as no demolition and construction activities would occur at the HBGS, development impact fees are not applicable.

Retrofitting activities would generate benefits such as increased property taxes, construction and operation employment income, and increased state and local sales taxes and fees. The economic benefits would be slightly less than those for the HBEP.

Soil and Water Resources

Retrofit Air Cooled Condenser Scenario

Under this scenario, Units 1, 2, 3 and 4 would not be demolished as they would for the proposed HBEP. This would result in slightly less disturbance, but this decrease in disturbance would be offset by the 43% larger disturbance required for an air-cooled condenser. Soil disturbance is therefore expected to be similar under this scenario to that of HBEP.

Like the HBEP, this alternative would comply with the SWRCB OTC policy. No difference is therefore expected for impacts to water quality under this scenario. This scenario would require use of a comparable amount of water to the HBEP scenario. Under both scenarios Units 1 and 2 would be air-cooled and the need for once-through cooling would be eliminated. The impacts to water supply would be similar to the proposed project because the project’s reliance on fresh water use would be reduced under this scenario.

Retrofit Wet Cooling Scenario Using Recycled Water

This scenario would use non-potable water for the makeup cooling water source. Such water is currently not available to the existing HBGS site and would require a recycled water pipeline to be constructed between the recycled water source and the project site. As described, two potential pipeline routes are possible. This additional disturbance would result in an increase in soil and wind erosion and therefore a slightly greater impact under this scenario. Construction of the wet cooling tower at the proposed location would result in the demolition of various support building and facilities. This scenario would result in similar soil disturbance when compared with the HBEP.

The environmental impact to the state's water supplies would be similar for this scenario as the HBEP, because it would reduce the project's reliance on fresh water for cooling. Like the HBEP, this alternative would comply with the SWRCB OTC policy. No difference is therefore expected for impacts to water quality under this scenario.

Traffic & Transportation

Retrofit Air Cooled Condenser Scenario

The air cooled condenser scenario would have less traffic and transportation impacts than the HBEP. It is assumed that this retrofit would utilize identical onsite and offsite laydown and construction staging areas as the HBEP, as well as resulting in less construction traffic volumes as the HBEP. Impacts from this No-Project Alternative scenario would be less than the proposed HBEP because of a smaller construction workforce and a shorter construction period.

Retrofit Wet Cooling Scenario Using Recycled Water

The wet cooling retrofit scenario would have greater traffic and transportation impacts than the HBEP. Construction and operation traffic would be increased due to the dispersion of construction related traffic impacts. The recycled water pipeline would affect additional roadways and intersections in the project area. Additional temporary roadway closures and staging areas would result in increased construction traffic impacts. The additional water treatment facility would also likely result in increased operation traffic. Impacts from this No-Project Alternative scenario would be greater than those of the proposed HBEP.

Transmission Line Safety and Nuisance

Retrofit Air Cooled Condenser Scenario

Under this No-Project Alternative scenario, the generating capacity would, at 430 MW be less than one half of the 939 MW proposed for HBEP. Since the same 230-kV transmission line (between HBGS and the on-site SCE Ellis Switchyard) would be used under the Air Cooled Condenser and all other operating scenarios, the electric field levels would be the same during all operations. The magnetic field (which depends on the amount of generated power) would be much less for the retrofitted, lower-capacity HBGS. Since HBEP operation would increase total power generation, it would increase the resulting magnetic field when compared to levels resulting from this retrofitted, lower-capacity HBGS.

Retrofit Wet Cooling Scenario Using Recycled Water

The generating capacity under the wet cooling scenario would, at 430 MW, be less than half of the 939 MW for the proposed HBEP. As with the air cooled condenser retrofit scenario, all the generated power would be transmitted via the same 230 kV transmission line presently used for power transmission between HBEP and the on-site SCE Switchyard. Since this grid voltage would not change during HBEP operation, the line's electric field (which depends on line voltage) would not change. The grid's magnetic field directly depends on the transmitted power, and therefore the lower power generation under the wet cooling scenario would lead to correspondingly lower magnetic field levels.

Visual Resources

Retrofit Air Cooled Condenser Scenario

The proposed HBEP would involve constructing the HBEP Power Block 1 on the northeast portion of the project site, including its three heat recovery steam generators (HRSGs) and stacks. The air cooled condenser (ACC) for the HBEP Power Block 1 would be constructed next to the HRSGs. The three HRSGs and stacks would be 92 feet tall and 120 feet tall, respectively. The ACC would be 209 feet long and 127 feet wide with a footprint of approximately 26,540 square feet (sq. ft.). The existing HBGS Units 1 and 2, Unit 5 peaker, and the decommissioned fuel oil tank at the farthest northeast portion of the site would be demolished. The HBEP Power Block 2 would be constructed on the west portion of the site and would replace the HBGS Units 3 and 4.

This No-Project Alternative scenario would require retrofitting the HBGS Units 1 and 2 with an ACC that would be constructed in the northeast portion of the HBGS site. Like the proposed HBEP, demolition and removal of the decommissioned fuel oil tank (and perhaps the existing HBGS Unit 5 peaker) would be required. The approximate footprint of the new ACC would cover an area of approximately 37,960 sq. ft. (a footprint increase of 43% compared to the ACC unit for the HBEP Power Block 1). Visual Resources staff assumes the vertical profile of the new ACC unit would be similar to the ACC units for the proposed HBEP (104 feet tall), or more than twice the height of the decommissioned fuel oil tank, which is approximately 40 feet tall. Under this No-Project Alternative scenario, the primary visual change would be construction of a new ACC unit in an area that is currently occupied by the much smaller fuel oil tank. The new ACC would appear as an expansive, horizontal, metal structure in the northeast portion of the project site.

The Visual Resources section includes an analysis of seven key observation points (KOPs) that were selected to represent sensitive views and viewer groups in the project area. Of those seven KOPs, staff identifies significant impacts at KOP 4 and KOP 5. Under the proposed HBEP, visual impacts for the other KOPs are considered less than significant largely because the overall visual change compared to existing conditions is considered low or low to moderate. In comparing this No-Project Alternative scenario to the proposed HBEP, staff concludes the following for KOPs where the impact conclusion is less than significant:

- Impact at KOP 1 – Represents views of the project site from Huntington State Beach. Similar to the proposed HBEP, the existing HBGS power block structures at the project site would dominate eastward views from KOP 1. It is possible that the new ACC unit would not be visible from KOP 1. The comparative impact is similar, and the impact conclusion is less than significant (i.e., the same as under the proposed HBEP).

- Impact at KOP 2 – Represents the view from the Huntington Beach Municipal Pier. Similar to the proposed HBEP, the existing HBGS power block structures would not dominate the landscape due to their distance from the viewer, and the addition of the ACC unit would not be noticeable. The comparative impact is similar, and the impact conclusion is less than significant.
- Impact at KOP 3 – Represents the view from Edison Community Park. Similar to the proposed HBEP, the existing HBGS power block structures and the new ACC unit would not dominate the landscape due to their distance from the viewer and the direction of view away from the immediate park environment. The comparative impact is similar, and the impact conclusion is less than significant.
- Impacts at KOPs 6 and 7 – KOP 6 represents the view from the Pacific Coast Highway (PCH) near Brookhurst Street. KOP 7 represents the view from the residential area along Frankfort Avenue northwest of the project site. For both of these KOPs, the existing HBGS power plant structures with the addition of an ACC unit behind existing Units 1 and 2 would not dominate the view due to their distance from the viewer. The comparative impacts are similar, and the impact conclusions are less than significant.

Staff's visual resources analysis for the proposed HBEP identifies significant impacts from constructing and operating the proposed HBEP that also apply to this No-Project Alternative scenario:

- Impact at key observation point (KOP) 4 – KOP 4 represents views from the area along Magnolia Street near its intersection with the Pacific Coast Highway (PCH). Views from KOP 4 and other nearby viewpoints represented by this viewpoint have the closest, unscreened views of the east and northeast portion of the project site. The existing HBGS Units 1 and 2 would remain on the southeast part of the site. Construction of the new ACC unit would introduce a new, expansive power plant structure in the northeast portion of the site (the same area as the proposed HBEP Power Block 1). The visual impact at KOP 4 would be similar to HBEP. As of publication of Part A of the preliminary staff assessment, staff had no information on visual screening concepts that could potentially reduce the impact at KOP 4 to a less-than-significant level. When new information on conceptual visual screening options becomes available, staff will re-evaluate the impact at KOP 4 for publication in the final staff assessment. Staff will also re-evaluate the comparative impact for this No-Project scenario.
- Impact at KOP 5 – KOP 5 represents views from Newland Street and the Huntington By-The-Sea Mobile Estates and RV Park next to the PCH. Views from KOP 5 and other nearby viewpoints represented by this KOP have foreground views of the west side of the project site that are largely unscreened. The existing HBGS Units 3 and 4 would remain on the southwest part of the site. No new, visually dominant structures would be constructed on the west side of the project site under this scenario. The visual impact at KOP 5 would be less than HBEP. For the same reasons as discussed above for KOP 4, the comparative impact conclusion for this KOP is undetermined and will be discussed in the FSA.

- Construction-Related Effects – Construction of the new ACC unit would require the presence and movement of heavy construction equipment and vehicles during demolition and construction activities. This visual resources impact could include off-site construction parking areas. Because the overall duration and extent of construction would be less compared to the proposed HBEP, this impact would be less than HBEP. Like the proposed project, this impact would be reduced to less than significant with implementation of mitigation measures.
- Project construction lighting – Although the construction schedule for this alternative is unknown, it is possible that portions of the project site could appear as brightly lit areas for limited times during construction of the new ACC unit. Construction activities have the potential to create a new source of substantial light or glare that could adversely affect nighttime views in the area. Because the overall duration and extent of construction would be less compared to the proposed HBEP, this impact would be less than HBEP. Like the proposed project, this impact would be reduced to less than significant with implementation of mitigation measures.
- Project operations lighting – Project operations lighting would increase with installation of new power plant structures on the northeast portion of the HBGS site. Under this No-Project Alternative scenario, it is assumed that structural lighting of the HBGS Units 1 and 2 would be unchanged, and overall lighting levels on the east side of the project site could increase somewhat compared to the proposed HBEP. Because no details on lighting are available for the proposed HBEP or the alternatives, staff concludes that the impact of project operations lighting would be similar to HBEP. Like the proposed HBEP, this impact would be reduced to less than significant with implementation of mitigation measures.
- Potential daytime glint or glare from project structures – The potential for glint or glare from the new ACC unit to adversely affect daytime views in the project area is considered a potentially significant impact of this alternative. This impact would be similar to HBEP. Like the proposed HBEP, this impact would be reduced to less than significant with implementation of mitigation measures.

Retrofit Wet Cooling Scenario Using Recycled Water

This No-Project Alternative scenario would require a structure for the water treatment facility approximately 23 feet tall and cover a minimum of 13,000 sq. ft. A long, narrow (approximately 60 feet wide, 650 feet long, and 50 feet tall) wet cooling tower would be constructed next to the water treatment facility. These new structures would be constructed across the HBGS site in the area between the existing HBGS power blocks and the SCE 230-kV switchyard. Various buildings and facilities would be demolished to allow construction of the water treatment facility and wet cooling tower on the HBGS site. It is unknown to Visual Resources staff if the demolished structures would be reconstructed elsewhere on the site.

Given the coastal location of the HBGS, it is assumed that a plume abated cooling tower would be required. Visible plume abatement could be achieved with a wet/dry tower to mix unsaturated hot air with saturated hot air to create an unsaturated exhaust. A wet/dry cooling tower would significantly lower the potential for visible plume formation, but depending on the design and ambient conditions at the site, visible plumes could still form above the cooling towers. If the HBGS was retrofitted with wet cooling, mitigation measures would be required to reduce the potential size and frequency of visible plume formation to acceptable levels.

As described above, visual impacts for KOPs 1, 2, 3, 6, and 7 under the proposed project are considered less than significant largely because the overall visual change compared to existing conditions is considered low or low to moderate. Staff compared this No-Project Alternative scenario to the proposed HBEP and concludes less than significant impacts for these KOPs. For the same essential reasons described under the Retrofit Air Cooled Condenser Scenario, the comparative impacts are similar, and the impact conclusions are less than significant.

Staff's visual resources analysis identifies significant impacts from constructing and operating the proposed HBEP that are described above for the air cooled retrofit scenario. The following apply to this No-Project Alternative scenario:

- Impact at KOP 4 –It is unknown if structures that would be demolished under this No Project Alternative scenario would be reconstructed at other locations on the site that could be visible from KOP 4. However, because the cooling tower would be less visually dominant compared to the HBEP Power Block 1, the visual impact at KOP 4 would be less than HBEP. Staff assumes that a plume abated cooling tower would be required and that mitigation measures would reduce the potential size and frequency of visible plume formation to acceptable levels. For the same reasons as discussed above for KOP 4 under the retrofit air cooled condenser scenario, the comparative impact conclusion for this KOP is undetermined.
- Impact at KOP 5 – Installation of the water treatment unit and wet cooling tower would introduce new power plant structures that would likely be visible from KOP 5. The existing HBGS Units 3 and 4 would remain on the southwest part of the site. Because the vertical profile of these structures would be less visually dominant compared to the ACC unit for the HBEP Power Block 2, the visual impact at KOP 5 would be less than HBEP. For the same reasons as discussed above, the comparative impact conclusion for this KOP is undetermined.
- Construction-Related Effects – Construction of the recycled water pipeline, water treatment unit, and wet cooling tower would require the presence and movement of heavy construction equipment and vehicles during demolition and construction activities. This visual resources impact could include off-site construction parking areas. Because the overall duration and extent of construction would be less compared to the proposed HBEP, this impact would be less than HBEP. Like the proposed HBEP, this impact would be reduced to less than significant with implementation of mitigation measures.
- Project construction lighting – Although the construction schedule for this alternative is unknown, it is possible that portions of the project site could appear as brightly lit areas for limited times during construction of the water treatment unit and wet cooling tower. Construction activities have the potential to create a new source of substantial light or glare that could adversely affect nighttime views in the area. Because the overall duration and extent of construction would

be less compared to the proposed HBEP, this impact would be less than HBEP. Like the proposed HBEP, this impact would be reduced to less than significant with implementation of mitigation measures.

- Project operations lighting – Project operations lighting would increase with installation of new power plant structures across the project site. Under this No-Project Alternative scenario, it is assumed that structural lighting of the existing HBGS power blocks would be unchanged. Overall lighting levels across the project site between the power blocks and the SCE switchyard could potentially increase compared to the proposed HBEP. Because no details on lighting are available for the proposed HBEP or the alternatives, staff concludes that the impact of project operations lighting would be similar to HBEP. Like the proposed HBEP, this impact would be reduced to less than significant with implementation of mitigation measures.
- Potential daytime glint or glare from project structures – The potential for glint or glare from the new power plant structures to adversely affect daytime views in the project area is considered a potentially significant impact of this alternative. This impact would be similar to HBEP. Like the proposed HBEP, this impact would be reduced to less than significant with implementation of mitigation measures.

Waste Management

Retrofit Air Cooled Condenser Scenario

Due to the proposed location of the air cooled condenser retrofit, removal of aboveground storage tanks (ASTs) located in the eastern portion of HBGS would not be required. There is no non-hazardous and hazardous demolition waste associated with the air cooled condenser retrofit. Therefore, there will be less waste generated by the air cooled condenser retrofit. It is also likely remediation of petroleum contaminated soil around AST bottoms and associated piping would be required for HBEP. If this were the case, then implementing this alternative further reduces the quantities of non-hazardous and hazardous waste. Thus, this No-Project Alternative scenario would have slightly less impacts when compared to the HBEP.

Retrofit Wet Cooling Scenario Using Recycled Water

Management of the waste generated during demolition, construction and operation of the HBEP would not result in any significant adverse impacts. Due to the proposed location of the wet-cooling retrofit, removal of ASTs located in the eastern portion of HBGS would not be required. Thus, this No-Project Alternative scenario would have at least the same impacts compared to the HBEP.

Worker Safety & Fire Protection

Retrofit Air Cooled Condenser Scenario

As compliance with LORS related to worker safety/fire protection at the proposed project would have no significant impacts off-site, there would be no significant impact on the public resulting from the proposed project. This scenario would also comply with

LORS and have no significant impacts off-site. Impacts from this No-Project Alternative scenario would be similar to the proposed HBEP.

Retrofit Wet Cooling Scenario Using Recycled Water

As compliance with LORS related to worker safety/fire protection at the proposed project would have no significant impacts off-site, there would be no significant impact on the public resulting from the HBEP. This scenario would also comply with LORS and have no significant impacts off-site. Impacts from this No-Project Alternative scenario would be similar to the proposed HBEP.

RECYCLED WATER SUPPLY ALTERNATIVE

Based on the analysis provided in the Soil & Water Resources section (as summarized in **Alternatives Table 1**), the HBEP would not result in significant impacts with respect to potable water use for process and steam makeup. However, Energy Commission policy directs power generation facilities to utilize recycled water when feasible. Therefore, the following alternative analyzes the use of recycled water by the HBEP. At this time, this analysis remains cursory. Several issue areas require additional information before a more comprehensive analysis can be completed. No comparison conclusions are presented in **Alternatives Table 1.** However, a more detailed evaluation and comparison of this alternative to the HBEP will be provided in the FSA.

This alternative would be identical to the HBEP, but would instead utilize recycled water instead of potable water for process and steam makeup. The use of recycled water by the HBEP would require a recycled water source, construction of a recycled water pipeline to the HBEP, and the addition of an on-site treatment facility. These components are described earlier for the No-Project Wet Cooling scenario.

ENVIRONMENTAL ANALYSIS

Air Quality

The use of recycled water by the HBEP would require the addition of a recycled water pipeline to the HBEP and an on-site treatment facility. Therefore, the construction related emissions and impacts would be somewhat greater than the proposed HBEP.

Biological Resources

The Recycled Water Alternative would include all components of the proposed HBEP, but would add a water pipeline that would be routed along the Santa Ana River and a water treatment facility within the HBEP site. The Santa Ana River and adjacent floodplain support native riparian vegetation, including southern cottonwood willow riparian forest, which is a sensitive vegetation community as designated by the California Department of Fish and Wildlife (CDFW 2013). The river and adjacent habitat also potentially support special-status plants and wildlife (CDFW 2013) and are jurisdictional waters of the U.S and state. Ground disturbance along the Santa Ana River during construction of the pipeline would result in greater impacts to native vegetation, common wildlife, special-status plants, and jurisdictional wetlands and waters than the proposed project. Construction of the water treatment facility on site would create additional noise and disturbance impacts to sensitive wildlife in adjacent areas during the construction phase in comparison to the proposed project. Projected operational noise levels of the water treatment facility are currently not available, but there may be greater noise impacts than the proposed project, but will be analyzed in the FSA. The extent of the increase would depend on the actual noise output of the facility as well as the operating schedule and placement within the site (i.e., how close the facility would be to adjacent marshes). All other construction and operational impacts to biological resources are expected to be the same as the HBEP.

Cultural Resources

Construction of the on-site portion of recycled water pipeline and water treatment facility would take place on the existing project site and would require depths of excavation similar to the proposed project, as analyzed in the **CULTURAL RESOURCES** section in Part A of this PSA. The addition of an equalization/storage tank at an unknown on-site location would also have the potential for impacts on buried archaeological resources. Staff therefore expects that potential impacts on buried archaeological resources of this retrofit scenario would be similar to those of the proposed HBEP.

Impacts to off-site cultural resources would be similar to the Retrofit Wet Cooling Scenario. As noted above, staff has results for only a portion of either of the potential routes. Because the entire route has not been surveyed, staff does not have specific information about other cultural resources that might be impacted by the construction of one of the two pipelines. When combined with the potential impacts of the HBEP, the Recycle Water Alternative would likely result in impacts greater than the proposed project.

Geology and Paleontology

The alignment of the recycled water pipeline traverses potentially active traces of the Newport-Inglewood fault. Should surface rupture occur along those traces of the potentially active fault, the conveyance of recycled water to the HBEP would be disrupted. Without an adequate source of process water, the operation of the power plant may be jeopardized. The net effect to the Recycled Water Alternative from surface fault rupture would be greater than the proposed HBEP. All other seismic related impacts would be the same as the proposed HBEP.

There are no geologic or mineralogic resources that would be impacted in the areas where the pipelines, cooling tower, and water treatment facility would be constructed. These facilities can also be designed and constructed such that geologic hazards are not a concern, similar to HBEP. Paleontological resources may be encountered in excavations that exceed 11 feet but impacts can be mitigated similar to the HBEP. Impacts from this alternative would be similar to the HBEP.

Hazardous Materials

Hazardous materials usage would be mitigated to insignificant through compliance with LORS and staff's proposed conditions of certification. Thus, this alternative would have impacts similar to the HBEP. Management of any hazardous materials during demolition, construction, and operation of the Recycled Water Alternative would not result in any significant adverse impacts. Due to the likely location of the on-site treatment facility, removal of aboveground storage tanks (ASTs) located in the eastern portion of HBGS would not be required. Thus, this alternative with mitigation of potential impacts due to hazardous materials usage to an insignificant level through compliance with LORS and staff's proposed conditions of certification, would have impacts similar to the HBEP.

Land Use

The Recycled Water Alternative would differ from the HBEP by constructing a water treatment facility on site in addition to the facilities proposed for the HBEP. The 23-foot high water treatment facility would be within the 50-foot maximum height limit of the Public-Semipublic (PS) zoning district. There appears to be more than adequate space available within the project site to accommodate the additional footprint of the roughly 13,000 square feet water treatment facility, while still maintaining the required minimum setbacks of the PS zoning district. Compliance with all other development standards of the PS zoning district appears to be achievable with this alternative. Therefore, Land Use issue area impacts of this alternative would be similar to the HBEP.

Noise and Vibration

The project as proposed would use the existing water supply pipeline. No new water lines or water treatment facilities would be constructed. To implement the Recycled Water Alternative described above, construction of a new water pipeline and a water treatment facility would be needed.

Construction of the new pipeline would temporarily elevate the existing ambient noise levels in the vicinity of the construction work. However, construction of linear facilities typically moves along at a rapid pace, thus not subjecting any one receptor to noise impacts for more than two or three days. Furthermore, construction activities would be limited to daytime hours. Construction of the HBEP, incorporating the water treatment facility, would temporarily result in higher construction noise levels than construction of the HBEP without this facility. However, construction of this facility would be temporary and limited to daytime. With implementation of conditions of certification similar to those proposed by staff in the **NOISE and VIBRATION** section in Part A of this document, construction impacts associated with this alternative would likely create a less-than-significant impact at adjacent noise-sensitive receptors.

All water pipes would be underground and silent during plant operation. Therefore, operation of the new water pipeline proposed in this alternative would not create any noise impacts. Operation of the water treatment facility may elevate the project's operational noise levels within the footprint of the power plant, but would not likely result in a measurable increase in the overall plant noise at the project's noise-sensitive receptors. With implementation of conditions of certification similar to those proposed by staff in the **Noise and Vibration** section in Part A of this document, operational impacts associated with this alternative would likely create a less-than-significant impact at adjacent noise-sensitive receptors.

Public Health

The use of recycled water by the HBEP, would require additional construction activities for the recycled water pipeline, on-site water treatment facility, and on-site cooling tower. Therefore, the diesel particulate matter (DPM) emissions and public health impacts would be somewhat greater than the proposed HBEP. No significant impacts would occur, and no conditions of certification would be required for either the proposed HBEP or this recycled water scenario.

During operation, under this alternative, since the proposed HBEP would use dry cooling, there would be no emissions of toxic metals or volatile organic compounds from cooling tower mist or drift. Also, there would be no health risk from the potential presence of the Legionella bacterium responsible for Legionnaires' disease. No significant impacts would occur, and no conditions of certification would be required for either the proposed HBEP or this recycled water scenario.

Socioeconomics

The Recycled Water Alternative would require the construction of a recycled water pipeline to the HBEP and an on-site treatment facility. The construction of both components would slightly increase the project construction workforce or the duration of project demolition/construction.

Impacts associated with substantial population growth in the project area and the need for new housing would be the similar to the HBEP. This alternative would not displace substantial numbers of people or existing housing; adversely affect acceptable levels of service for police protection, schools, parks, and recreation; impacts would be similar to those for the HBEP, but would be greater than HBGS.

This alternative would be subject to development impact fees (Chapter 17 of the Huntington Beach Municipal Code- Police Facilities and Parkland Acquisition and Park Facilities Development Impact Fees), and as the same new gross square footage of buildings would be proposed under this alternative, the fees paid to the city would be similar to those assessed for the HBEP.
This alternative would generate benefits such as increased property taxes, construction and operation employment income, and increased state and local sales taxes and fees. The economic benefits would be slightly greater than those for the HBEP and greater than the HBGS. Economic benefits would be greater for the HBEP and the Recycled Water Alternative as activities beyond day-to-day plant operations at the HBGS would generate increased economic activity, thus resulting in increased taxes and income expenditure.

Soil and Water Resources

Under the Recycled Water Project Alternative, the project would use recycled water in the same manner described in the "No Project – Wet Cooling" scenario, and would use a similar amount as the proposed project. The proposed project would be dry-cooled and could use up to 134 acre-feet per year (AFY) of potable water (Comments on Staff's

Supplemental Focused Analysis, PSA Part A, TN: 201582). Staff assumes that if the recycled water alternative is chosen as the preferred alternative, the project would require at least 134 acre feet per year (AFY). Recycled water would be supplied by the OCSD, via Route 1 or Route 2 (as described above). Route 1 would require a 1.9-mile pipeline along Hamilton Avenue that interconnects with the OCSD pipeline between Plant 1 and Plant 2 that runs along the Santa Ana River. Route 2 would require a 2.8-mile pipeline that would deliver water directly from the OCSD Plant 2 to the HBEP. This route would require that water be pumped uphill from Plant 2 to Hamilton Avenue, along Hamilton Avenue until it reaches Newland Street, then south to the HBEP.

Staff contacted the OCSD in October and December 2013 and spoke with Jim Colston, the district's environmental compliance manager (TN: 201394). The district has sufficient quantities of unspoken-for recycled water available to meet the needs of the HBEP. Plant 2 has about 100 million gallons per day (MGD) of secondary treated, disinfected recycled water available, with total dissolved solids in the 1,500 to 2,000 milligrams per liter (mg/L range). Plant 1 may have tertiary treated water available in the future, but it will depend on whether current users exercise their future water use options. Secondary treated disinfected recycled water from either Plant 1 or 2 would be free to the project. Both of these recycled water streams are currently being discharged to the Pacific Ocean.

The applicant provided sufficient information about the feasibility of delivering recycled water to the project site. The applicant stated in the AFC, Section 6.6.3 that the cost of the pipeline construction could be up to “$1.6 million” and the cost of the additional onsite treatment facilities could be up to “$2 million” (HBEP, 2012a). Staff calculated the cost of potable water use for the 30-year life of the project, assuming the proposed project could use up to 134 AFY. The potable water cost includes both the unit (748 gallon) cost ($1.7535 per unit) of the water and the daily meter cost. Staff assumed the project would be billed based on the “8-inch Fire Meter” rate of $43.2239 per day. The cost of urban water is expected to increase between 20 to 41% by 2030 (relative to 2011) based on water supply studies by the Pacific Institute (Gleick et al., 2005). Therefore, it would be reasonable to assume that a 30% increase in the cost of potable water could be expected by 2030 (in 20 years) or about 45% during the expected 30-year life of the project. The combined cost for potable water for the 30-year life of the project would be $3.54 million without taking into account the rising cost of water, or $4.23 million if the increase in water cost is considered. Thus the cost of recycled water would be approximately $3.6 million for the pipeline and treatment facility, versus at least $3.54 million for potable water. California Water Code 13550, Energy Commission policy, and Water Board policy require the use of recycled water when feasible. Based on information provided by the OCSD and the applicant’s responses, the recycled water supply is feasible (Comments on Staff's Supplemental Focused Analysis, PSA Part A, TN: 201582).. The applicant states that the following criteria must be considered when determining the feasibility of recycled water:

1. The source of recycled water is of adequate quality for the uses and is available for the uses.

   Staff Response: Though the water currently available through OCSD is not disinfected tertiary-treated water, it is of reasonable quality to be treated for use. The expected potable water would be about 400 mg/L total dissolved solids

(TDS); the recycled water would be about 1,750 mg/L and higher in other constituents like ammonia. The recycled water would also require disinfection. The project would need to do onsite treatment regardless of source water.

2. The recycled water may be furnished for these uses at a reasonable cost to the user. In determining reasonable cost, the state board shall consider all relevant factors, including, but not limited to, the present projected costs of supplying, delivering, and treating potable domestic water for these uses and the present and projected costs of supplying and delivering recycled water for these uses, and shall find that the cost of supplying the treated recycled water is comparable to, or less than, the cost of supplying potable domestic water.

   Staff Response: Recycled water could be furnished at no cost to the HBEP. As shown above, the applicant's proposed construction cost for the recycled water treatment system and pipeline could be as high as $3.6 million, excluding the additional treatment costs. The cost of potable water could be as high as $4.23 million for the 30-year project life. These calculations show that the cost of recycled water is comparable to that of potable water and should be considered.

3. After concurrence with the State Department of Health Services, the use of recycled water from the proposed source will not be detrimental to public health.

   Staff Response: The proposed recycled water is not expected to have human contact and is not expected to be detrimental to public health.

4. The use of recycled water for these uses will not adversely affect downstream water rights, will not degrade water quality, and is determined not to be injurious to plantlife, fish, and wildlife.

   Staff Response: The proposed recycled water has no downstream users and is currently being discharged to the Pacific Ocean. Using this water would create a net benefit for the Pacific Ocean in terms of water quality.

Based on cost estimates provided by the applicant (HBEP, 2012a) and the potable water cost calculated by staff, the recycled water alternative seems reasonable. Further analysis of California Water Code 13550 also supports the use of recycled water by the proposed project.

Traffic & Transportation

The recycled water alternative would require the construction of an additional facility on the HBEP site and the installation of a new pipeline in the project vicinity. This would likely result in somewhat greater impacts to existing traffic in the area. The installation of a new pipeline would require additional temporary construction workforce, which would affect the Level of Service (LOS) of the potentially impacted roadway intersections in the area.

Construction of a new pipeline would result in temporary lane closures, which would further reduce the LOS along the pipeline route. These impacts would primarily be during project construction and would be temporary in nature. However, these impacts would be somewhat greater than the HBEP. It is not likely that the recycled water alternative would affect the LOS of roadway intersections in the project area to the extent that the LOS would be degraded beyond acceptable limits established by the city of Huntington Beach or the county of Los Angeles. The recycled water alternative would include a new treatment facility on site but is not anticipated to affect emergency access on-site.

Transmission Line Safety and Nuisance

The addition of a recycled water line, on-site recycled water facility, and use of recycled water under this alternative would have no effect to the transmission line safety and nuisance analysis of the proposed HBEP. The addition of these facilities and use of recycled water by the HBEP would not alter the transmission of power generated. Therefore, impacts would be identical for this alternative as those of the proposed HBEP.

Visual Resources

This alternative would require construction of an underground, recycled water pipeline to convey secondary effluent to a new water treatment facility at the HBEP site. The pipeline would parallel existing roadways and possibly extend along a channelized segment of the Santa Ana River to connect to the Orange County Sanitation District Plant #2. The recycled water pipeline would enter the project site from Newland Street to connect with a water treatment facility that would be constructed in the central portion of the site between Power Blocks 1 and 2 for the proposed HBEP. The structure for the on-site water treatment facility and related equipment would be approximately 23 feet high and cover at least 13,000 square feet.

Construction of the recycled water pipeline would cause temporary impacts on visual resources along public rights-of-way, including Hamilton Avenue and Newland Street. Pipeline construction would include movement of construction equipment and materials and generation of dust along the pipeline construction corridor. Depending on the selected recycled water source, construction-related impacts on visual resources could also occur along a segment of Brookhurst Street and the lower Santa Ana River. Viewer groups would primarily include local residents, pedestrians, and motorists along the construction corridor. Although construction activities along the pipeline route would be clearly visible from public use areas, impacts on visual resources would be short term as the work on pipeline segments progressed along the route. Due to the temporary nature and relatively short duration that is assumed for pipeline construction, potential impacts on visual resources are less than significant. No mitigation measures for construction-related visual effects other than those required for the proposed HBEP would be required. Construction-related impacts on visual resources for this alternative would be similar to HBEP.

The on-site water treatment facility would likely be set back from public use areas near the project site. The water treatment facility would likely have a lower vertical profile than the visually prominent structures that would be constructed for the HBEP (e.g., the heat recovery steam generators, stacks, and air cooled condensers). Assuming the water treatment facility would not exceed approximately 23 feet in height, this alternative would probably not cause a noticeable change in the massing and visual prominence of power plant structures. Staff’s visual resources analysis for the project identifies significant impacts from constructing and operating the proposed HBEP that also apply to the Recycled Water Alternative. The overall impacts on visual resources would be similar to HBEP.

Waste Management

This recycled water alternative identifies the potential sources of recycled water would be the Orange County Sanitation District (OCSD) Plant 1 or Plant 2. The primary infrastructure required to facilitate the operation would include one pipeline, a water treatment facility (Title 22 Recycled Water Facility (RWF)), and an equalization/storage tank. The Title 22 RWF would treat OCSD secondary treated effluent on-site and would be designed to produce tertiary treated recycled water suitable for unrestricted use. The amount of waste generated during operation of the RWF would increase with the use of recycled water.

Management of the waste generated during demolition, construction and operation of the HBEP would not result in any significant adverse impacts. Due to the proposed location of the wet-cooling retrofit, removal of aboveground storage tanks (ASTs) located in the eastern portion of Huntington Beach Generating Station would not be required. Thus, this Project Alternative would reduce the amount of waste generated during demolition from possible remediation and/or disposal or recycling of waste material, but would create more operation waste due to sludge from the Title 22 RWF.

Worker Safety & Fire Protection

The addition of the Recycled Water Alternative infrastructure and use of recycled water by the HBEP would have no significant changes to the level of worker safety and fire protection required. Thus, this alternative would have impacts similar to the HBEP in the potential impact on fire and emergency response during demolition, construction, and operation of the HBEP would not result in any significant adverse impacts. Due to the proposed location of the wet-cooling retrofit, removal of ASTs located in the eastern portion of Huntington Beach Generating Station would not be required. Thus, this alternative would have similar impacts to the HBEP.

CEQA ENVIRONMENTALLY SUPERIOR ALTERNATIVE

In CEQA analyses, the “no project” alternative is compared to the proposed project and determined to be superior, equivalent, or inferior to it. The CEQA Guidelines state that “the purpose of describing and analyzing a “no project” alternative is to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project” (Cal. Code Regs., tit. § 15126.6(i)). Toward that end, the “no project” analysis considers “existing conditions” and “what would be reasonably expected to occur in the foreseeable future if the project were not approved…” (§ 15126.6(e)(2)). The No-Project Alternative (i.e., the retrofit scenarios discussed above) provides a baseline against which the effects of the proposed action may be compared.

Within this PSA, the No-Project Alternative could be considered to be environmentally superior to the proposed project on the basis of the minimization or avoidance of a number of physical environmental impacts. As shown in **Alternatives Table 1**, when comparing any significant impacts of the HBEP (both mitigable and unmitigable) against the No-Project Alternative scenarios, there would be a reduction to certain Air Quality and Biological Resources impacts. Additionally, as shown in **Alternatives Table 1**, the No-Project Alternative scenarios would result in a reduction to less than significant impacts identified for **NOISE AND VIBRATION, PUBLIC HEALTH, SOCIOECONOMICS, TRANSMISSION LINE SAFETY AND NUISANCE, VISUAL RESOURCES, AND WASTE MANAGEMENT**. Analysis supporting these conclusions is provided within the Alternatives Evaluated in Full Detail discussion. Also shown in **Alternatives Table 1** are those impacts where the No-Project Alternative scenarios would have similar or greater impacts when compared to those of the proposed HBEP. When reviewing the impact summary comparisons provided in **Alternatives Table 1** for all issue areas, the No-Project Alternative scenarios would lessen potential impacts of the HBEP.

While reducing impacts in these resource areas, the No-Project scenarios would only meet half of the basic project objectives. In addition, the CEQA Guidelines (Cal. Code Regs., tit. 14, §15126.6[e][2]) require that, if the environmentally superior alternative is the No-Project Alternative, "the EIR shall also identify an environmentally superior alternative among the other alternatives." In terms of physical effects on the environment, the environmentally superior alternative (other than the No-Project Alternative) is the proposed HBEP.

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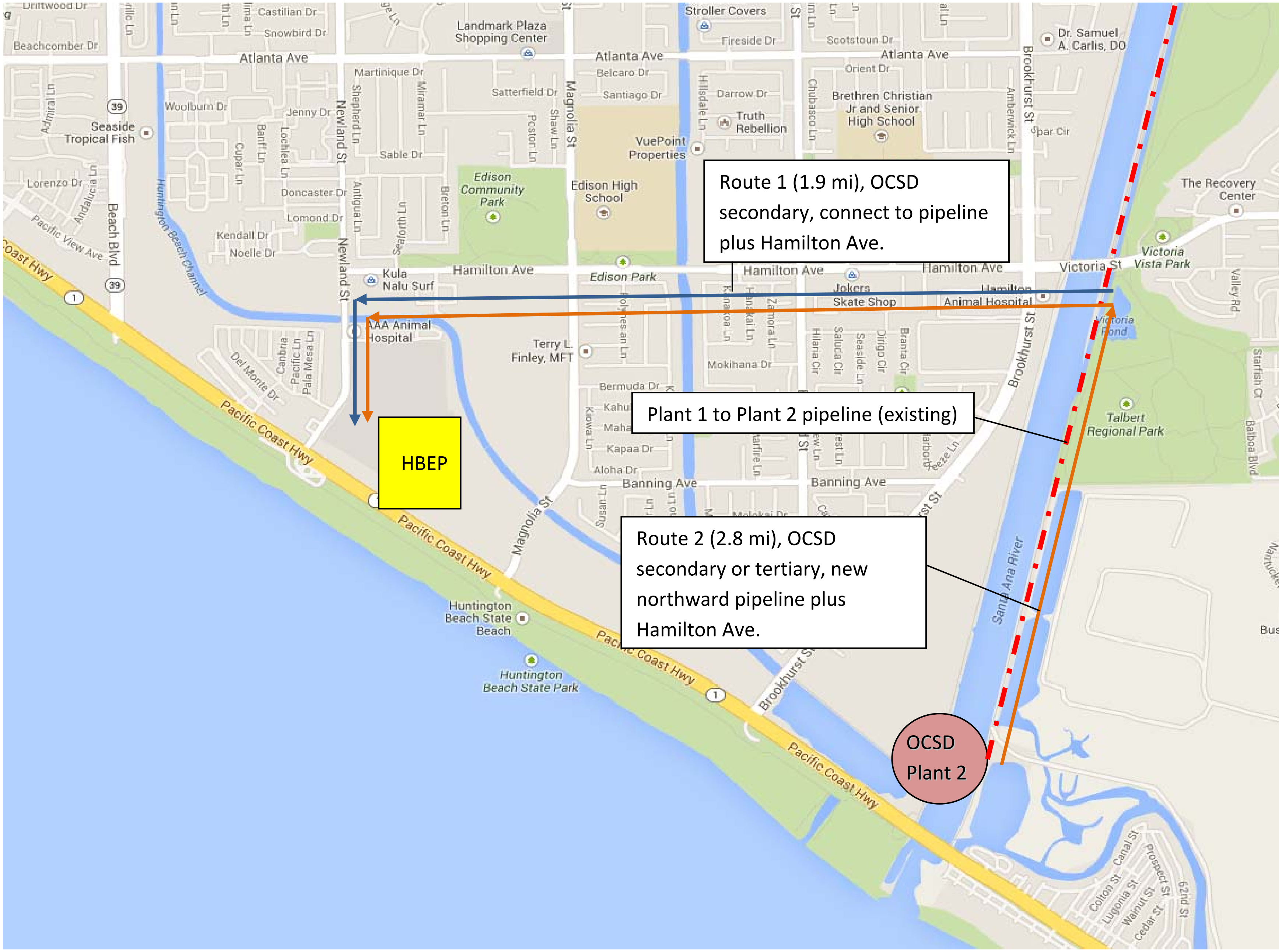
Route 1 (1.9 mi), OCSD secondary, connect to pipeline plus Hamilton Ave.
Plant 1 to Plant 2 pipeline (existing)
Route 2 (2.8 mi), OCSD secondary or tertiary, new northward pipeline plus Hamilton Ave.
HBEP
OCSD Plant 2
Hamilton Ave
Victoria St
Newland St
Magnolia St
Brookhurst St
Pacific Coast Hwy
Santa Ana River
Banning Ave
Atlanta Ave
Huntington State Beach
Talbert Regional Park
Edison High School
Edison Park

HUNTINGTON BEACH ENERGY PROJECT (12-AFC-02)
PRELIMINARY STAFF ASSESSMENT – Part B
PREPARATION TEAM

Executive Summary .... Felicia Miller

~~Introduction .... Part A - Felicia Miller~~

~~Project Description .... Part A - Felicia Miller~~

Environmental Assessment

Air Quality ....

~~Biological Resources .... Part A - Anwar Ali / Heather Blair / Jennifer Lancaster~~

~~Cultural Resources .... Part A - Gabriel Roark / Thomas Gates / Amber Grady~~

~~Hazardous Materials Management .... Part A - Geoff Lesh, PE, CSP, CFPS~~

~~Land Use .... Part A - Steven Kerr~~

~~Noise and Vibration .... Part A - Edward Brady / Shahab Khoshmashrab~~

Public Health .... Huei-An (Ann) Chu

~~Socioeconomics .... Part A - Lisa Worrall~~

~~Soil and Water Resources .... Part A - Mike Conway, P.G.~~

~~Traffic and Transportation .... Part A - Jonathan Fong~~
~~Visual Plume Modeling .... Part A - Tao Jiang, Ph.D., P.E. / Joseph Hughes~~

~~Transmission Line Safety and Nuisance .... Part A - Obed Odoemelam, Ph.D~~

~~Visual Resources .... Part A - Jeanine Hinde~~

~~Waste Management .... Part A - Ellie Townsend-Hough~~

~~Worker Safety and Fire Protection .... Part A - Geoff Lesh, PE, CSP, CFPS~~

Engineering Assessment

~~Facility Design .... Part A - Shahab Khoshmashrab~~

~~Geology and Paleontology .... Part A - Casey Weaver, CEG~~

~~Power Plant Efficiency .... Part A - Edward Brady / Shahab Khoshmashrab~~

~~Power Plant Reliability .... Part A - Shahab Khoshmashrab~~

~~Transmission System Engineering .... Part A - Laiping Ng / Mark Hesters~~

Alternatives .... Negar Vahidi / Scott Debauche

~~Compliance Conditions .... Part A - Eric Veerkamp~~

Project Assistant .... Teraja Golston