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HUNTINGTON BEACH ENERGY PROJECT

Final Staff Assessment, Part 2 and Supplemental Testimony in Response to Questions for the Petition to Amend the Huntington Beach Energy Project Decision

CALIFORNIA
ENERGY COMMISSION
Edmund G. Brown, Jr, Governor

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HUNTINGTON BEACH ENERGY PROJECT PETITION TO AMEND (12-AFC-02C)
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INTRODUCTION

This Final Staff Assessment (FSA) Part 2 is being published by the California Energy Commission staff for the Huntington Beach Energy Project (HBEP) Petition to Amend (PTA) the Energy Commission Decision (Decision) (12-AFC-02C). Part 2 of the FSA includes staff's final evaluation of Air Quality and Public Health impacts of the Amended HBEP.

FSA Part 2 contains staff's final, independent, objective evaluation of the engineering, environmental, and safety aspects of the project, and a determination of whether the project conforms to all applicable laws, ordinances, regulations and standards (LORS) for Air Quality and Public Health. FSA Part 2 is based on the information provided by the applicant, government agencies, interested parties, independent research, and other sources available at the time the FSA Part 2 was prepared. 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. FSA Part 2 contains analyses and responses to comments similar to those normally contained in a Final Environmental Impact Report required by the California Environmental Quality Act (CEQA).

This FSA Part 2 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. FSA Part 2 serves as staff's formal testimony in evidentiary hearings to be held by the HBEP Amendment Committee assigned to hear this case. The Committee will hold evidentiary hearings and will consider the recommendations presented by the staff, the applicant, intervenors, government agencies, and the public, prior to proposing its decision. The full Energy Commission will make the final decision, including findings, after the Committee's publication of its proposed decision.

On September 4, 2015, AES Huntington Beach Energy, LLC, submitted a petition to amend the Decision (12-AFC-02C - the Licensed HBEP). The requested changes to the project are the result of the selection by Southern California Edison (SCE) of the revised AES project in the 2013 Local Capacity Requirements Request For Offers. The PTA revises the nominal capacity of the facility and uses different generation technologies than that permitted in the Licensed HBEP Decision.

PROPOSED PROJECT LOCATION AND DESCRIPTION

The HBEP footprint is located within the existing operating Huntington Beach Generating Station (HBGS), located in Huntington Beach, California at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (Highway 1) and Newland Street. The site containing boiler units 1-4, is privately owned land, and is relatively flat with an approximate elevation of 10 to 14 feet above mean sea level. The project borders a manufactured home/recreational vehicle park on the west, a tank farm on the north, the Magnolia Marsh wetlands on the north and east, and the Pacific Ocean and Huntington Beach State Park on the south and southwest.

The PTA proposes to modify the previously approved 939-MW power plant to a new configuration that would total 844-MWs. Construction would commence in two phases with the first phase consisting of a natural gas-fired, combined-cycle, air-cooled, 644-MW electrical generating facility. After the first phase combined-cycle power block is operational, phase two construction would begin for two 100-MW simple-cycle gas turbines (SCGT). The second phase: two LMS-100 PB combustion turbine generators, are currently not under a Power Purchase Agreement (PPA) with SCE. However, AES is requesting to license and install these turbines for future projected needs under the proposed amendment (12-AFC-02C) through a separate PPA with SCE.

No new offsite linear facilities are proposed as part of this project.

If the Amended HBEP is approved by the Energy Commission, construction and demolition activities at the project site are anticipated to take approximately 9 years, lasting through the fourth quarter of 2025. The PTA indicates a construction schedule for the various phases of activities with the combined-cycle, gas turbine (CCGT) phase I, power block 1, anticipated beginning in the second quarter of 2017 with commercial operation of power block 1 during the second quarter of 2020. The demolition of existing units 3 &4 is estimated to begin during the 2nd quarter of 2020 and continue to the 2nd quarter for 2022. Construction of the SCGT phase 2, power block 2, is anticipated to begin during the first quarter of 2022 with commercial operation occurring the first quarter of 2024. Existing HBGS units 1 and 2 would then be demolished to their steam turbine decks.

ENERGY COMMISSION AMENDMENT REVIEW PROCEDURES

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

PUBLIC AND AGENCY COORDINATION AND OUTREACH EFFORTS

PUBLIC AND AGENCY NOTICE AND OUTREACH

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

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

Libraries

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

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

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

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

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

Mary Wilson Library
707 Electric Avenue
Seal Beach, CA 90740

Fountain Valley Library
17635 Los Alamos
Fountain Valley, CA 92708

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

Energy Commission's Public Adviser's Office

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

Public Workshops

On December 8, 2015 Energy Commission staff conducted a public workshop in Huntington Beach to facilitate public, agency, and intervenor participation. The workshop included discussion of data requests and responses, allowing for a transparent and comprehensive discussion of technical areas related to the proposed project.

Informational Hearing, Scoping Meeting, and Site Visit

The Committee of two Energy Commissioners and a Hearing Advisor overseeing the processing of the Amended HBEP PTA sponsored a Public Site Visit, Environmental Scoping Meeting, and Informational Hearing on December 8, 2015 in Huntington Beach. Representatives of interested agencies, elected officials, and members of the public were invited to find out about, and provide comments on, the project and see the project site.

After publication of the Preliminary Staff Assessment (PSA), a PSA workshop was held at the Huntington Beach Library on July 12, 2016. During the workshop, specific time for public participation was allocated, and public comments were taken. This workshop provided a public forum for the applicant, the public, staff and participating agencies to interact regarding project issues.

Consultation with Local Native American Communities

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

Tribal Consultation

A check of the NAHC sacred lands files resulted in negative findings within a one-half-mile radius of the proposed project. Staff sent letters to all of the NAHC-listed tribes for the project vicinity, inviting them to comment on the proposed project and offered to hold face-to-face consultation meetings if any tribal entities so requested. Staff received comments from the Juaneño Band of Mission Indians, Acjachemen Nation, and Gabrielino-Tongva Tribe that tribal monitors should be required during project ground disturbing activities. A letter from the United Coalition to Protect Panhe stated concern that the project site is culturally sensitive and encouraged staff to promote avoidance as mitigation for any cultural resource discoveries connected with the proposed project. Provisions for avoidance and monitoring are contained in Conditions of Certification **CUL-6** and **CUL-7**.

RESPONSE TO COMMENTS

Several public agencies and one public member filed comments on the project. (see **Executive Summary - Table 2** below). Staff has addressed these comments within each section of the FSA. Supplemental testimony in response to questions from FSA Part 1 has been added to the FSA Part 2.

Executive Summary - Table 2
HBEP List of Agency/Public Comments

NAME	DATE(S)	REQUEST TO PARTICIPATE	Other/LORS	ALTERNATIVES	AIR / PUBLIC HEALTH	BIOLOGY / BOTANY / WILDLIFE	CULTURAL RESOURCES	COMPLIANCE CONDITIONS	CUMULATIVE IMPACTS	GEOLOGY/PALEONTOLOGY	HAZARDOUS MATERIALS	HOURS OF OPERATION	INTAKE AND OUTFALL PIPELINES	NOISE /CONSTRUCTION NOISE	PROJECT DESCIPTION	PUBLIC HEALTH	TRANSMISSION LINE SAFETY & NUISANCE	TRANSMISSION SYSTEM ENGINEERING	SOCIECONOMICS	SOIL & WATER RESOURCES	TRAFFIC/LAND USE	VISUAL RESOURCES	WASTE MANAGEMENT	WORKER SAFETY/FIRE PROTECTION
City of Huntington Beach	11/23/15		x								x			x	x						x	x		
Coastal Commission	3/11/16					x			x	x		x		x										
CAISO	12/3/15		x	x																				
Huntington Beach Wetlands Conservancy	04/18/16					x								x								x		
Mike M. Trelles	07/05/16				x						x			x		x					x			
AES – Project Owner	7/21/16			x	x	x	x	x		x					x	x	x	x		x	x	x	x	
City of Huntington Beach	07/22/16		x		x									x	x					x	x	x		x
CASIO	08/09/16			x																				
California Coastal Commission	8/15/16					x								x							x			
AES – Project Owner	8/25/16			x																				
City of Huntington Beach	12/02/16		x			x								x	x						x	x		

PROJECT BACKGROUND

The Amended HBEP is proposed as an amendment to the Decision for the Licensed HBEP. The amended proposal is to replace the existing power block technology with more efficient and current turbine technology along with the supporting equipment and infrastructure.

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

PROJECT OBJECTIVES

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

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

PROJECT ALTERNATIVES

1. Project alternatives developed for the Amended HBEP are fully discussed in the **Alternatives** section of FSA Part 1.

SUMMARY OF ENVIRONMENTAL CONSEQUENCES AND MITIGATION

Below is a summary of environmental consequences and mitigation proposed in this FSA. This section also provides a summary of information that was not available or included in the Preliminary Staff Assessment (PSA) that is analyzed in the FSA Part 2.

Executive Summary Table 1-2

Updated Environmental and Engineering Assessment

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

AIR QUALITY/GREENHOUSE GASES:

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

Staff's air quality analysis is based upon the thorough LORS analysis conducted by SCAQMD, which evaluated the Amended HBEP relative to baseline ambient air quality conditions. Staff incorporated the SCAQMD's conditions as mitigation measures for the Amended HBEP. Staff concludes that operating period mitigation would be provided in the form of Regional Clean Air Incentives Market (RECLAIM) Trading Credits (RTCs) and emission reduction credits (ERCs) as required by SCAQMD rules and that these measures would fully mitigate emissions of all nonattainment pollutants and their precursors. These mitigation measures reduce potential operational impacts of the proposed project to less than significant. While the proposed project modifications constitute a considerable change in fact and circumstance from the project as licensed, there are no new significant environmental effects or a substantial increase in the severity of previously identified significant effects associated with those modifications. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Energy Commission Final Decision is necessary for Air Quality.

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

The proposed GE 7FA.05 combined-cycle turbines are expected to comply with the federal Standards of Performance for Greenhouse Gas Emissions (or Clean Air Act section 111[b]) of 1,000 pounds of carbon dioxide per gross megawatt hour (lb CO_2/MWh, gross) or (1,030 lb CO_2/ MWh, net) for new base load natural gas fueled turbines. The proposed GE LMS-100PB simple-cycle turbines are expected to comply with the limit of 120 lb CO_2 per million Btus (MMBtu) of natural gas heat input for new non-base load natural gas fueled turbines. Should the combined-cycle turbines operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. No specific GHG conditions of certification are proposed in the **Appendix AIR-1**, but **AQ-15** and **AQ-61** would ensure compliance with the new federal standards.

PUBLIC HEALTH

California Energy Commission staff has analyzed the potential human health risks associated with construction, demolition and operation as proposed in the petition to amend (PTA) the Final Decision for Huntington Beach Energy Project (HBEP, 12-AFC-02). Staff concludes that there would be no significant health impacts from the HBEP's potential toxic air contaminant (TAC) emissions. Staff also concludes that the proposed modification would not affect the HBEP's ability to comply with applicable health laws, ordinances, regulations, and standards (LORS).

In accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Energy Commission Final Decision is necessary for Public Health. The proposed project modifications constitute a considerable change in facts and circumstances from the 2014 Decision and it was necessary to evaluate the proposed project's incremental impacts on Public Health. There are no new significant environmental effects, nor is there a substantial increase in the severity of previously identified significant effects regarding public health impacts.

CUMULATIVE IMPACTS

Preparation of a cumulative impact analysis is required under CEQA. In the CEQA Guidelines, "a cumulative impact consists of an impact which is created as a result of the combination of the project evaluated in the EIR together with other projects causing related impacts"[1]. Cumulative impacts must be addressed if the incremental effect of a project, combined with the effects of other projects is "cumulatively considerable."[2] Such incremental effects are to be "viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects."[3] Together, these projects comprise the cumulative scenario which forms the basis of the cumulative impact analysis.

CEQA also states that both the severity of impacts and the likelihood of their occurrence are to be reflected in the discussion, "but the discussion need not provide as great detail as is provided for the effects attributable to the project alone. The discussion of cumulative impacts shall be guided by standards of practicality and reasonableness, and shall focus on the cumulative impact to which the identified other projects contribute rather than the attributes of other projects which do not contribute to the cumulative impact."[4]

DEFINITION OF THE CUMULATIVE PROJECT SCENARIO

Cumulative impacts analysis is intended to identify past, present, and probable future projects that are closely related either in time or location to the project being considered, and consider how they have harmed or may harm the environment. Most of the projects on the Master Cumulative Project List below are required to undergo their own independent environmental reviews under CEQA. Staff developed the list by contacting planning staff with the city of Huntington Beach, Costa Mesa, New Port Beach, Fountain Valley, Seal Beach, Cypress, Long Beach and surrounding jurisdictions in Orange County. Staff also conducted a review of project information from other agencies, including the California Department of Transportation, and the CEQANet database to develop a list of past, present, and reasonably foreseeable projects.

Under CEQA, there are two acceptable and commonly used methodologies for establishing the cumulative impact setting or scenario: the "list approach" and the "projections approach." The first approach would use a "list of past, present, and

[1] Cal. Code Regs., tit. 14, § 15130(a)(1)
[2] Cal. Code Regs., tit. 14, § 15130(a)(2)
[3] Cal. Code Regs., tit. 14, § 15164(b)(1)
[4] Cal. Code Regs., tit. 14, § 15130(b)

probable future projects producing related or cumulative impacts."[5] The second approach is to use a "summary of projections contained in an adopted general plan or related planning document, or in a prior environmental document which has been adopted or certified, which described or evaluated regional or area-wide conditions contributing to the cumulative impact."[6] This FSA uses the "list approach" for purposes of state law to provide a tangible understanding and context for analyzing the potential cumulative effects of the proposed project. All projects used in the cumulative impacts analyses for this FSA are listed in the cumulative projects table (**Executive Summary Table 2**), and locations are shown on **Executive Summary Figure 1**.

APPROACH TO CUMULATIVE IMPACT ANALYSIS

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

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

Evaluate the effects of the amended HBEP with foreseeable future projects that occur within the area of geographic effect defined for each discipline.

Executive Summary - Table 2
HBEP Amended Cumulative Project List

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
1	Huntington Beach Generating Station Demolition (Demolition of Units 3 & 4)	Demo/removal of Units 3 & 4 from the existing Huntington Beach Generating Station.	Huntington Beach Generating Station, Huntington Beach	0.05	Demo estimated Q2 2020 to Q2 2022 (24 mo.)
2	Poseidon Desalination Plant	A 50-million gallon-per-day seawater desalination facility located on 11-acre portion of the existing Huntington Beach Generating Station (HBGS) facility. Project would use existing HBGS seawater intake and outfall pipelines for operations.	21730 Newland St, Huntington Beach	0.22	Planning and in review with the California Coastal Commission

[5] Cal. Code Regs., tit. 14, § 15130(b)(1)(A)

[6] Cal. Code Regs., tit. 14, § 15130(b)(1)(B)

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
3	Magnolia Oil Storage Tank and Transfer Facility Demolition and Removal	Demolition and removal of three empty above ground crude oil storage tanks and ancillary site improvements.	21845 Magnolia St, Huntington Beach	0.35	In Progress
4	Newland St Residential (Pacific Shores)	Develop and subdivide former industrial site to residential with 204 multi-family residential units and two-acre public park.	21471 Newland St, Huntington Beach	0.40	Completed
5	Remedial Action Plan for Ascon Landfill Site	Remedial Action Plan (RAP) includes partial removal of waste materials and construction of protective cap over remaining waste materials.	Magnolia St and Hamilton Ave, Huntington Beach	0.43	Plan Check
6	Hilton Waterfront Beach Resort Expansion	Nine-story tower with 156 new guestrooms, appurtenant facilities, 261 parking spaces, a loading dock and other back-of-house facilities.	21100 Pacific Coast Hwy, Huntington Beach	1.02	Plan Check
7	Brookhurst Street Bridge Preventative Maintenance Project	Repair and rehabilitate the Brookhurst Street Bridge in the city of Huntington Beach.	Brookhurst St Bridge, Huntington Beach	1.11	Plan Check
8	P2-92 Sludge Dewatering and Odor Control	Build new sludge and odor control facilities at existing Plant 2.	Santa Ana River Channel, Huntington Beach	1.17	Construction scheduled Spring 2016
9	Pacific City	516 condominiums; 8 story-250-room hotel, spa and health club; and 191,100 sq. ft. visitor-serving commercial with retail, office, restaurant, cultural, and entertainment	21002 Pacific Coast Hwy, Huntington Beach	1.26	Under Construction
10	Pierside Pavilion Expansion	Proposes to construct a connecting four-story, mixed-use, visitor serving/office building and storefront extension.	300 Pacific Coast Hwy, Huntington Beach	1.51	Plan Check
11	The Strand	Retail, restaurants, offices, and a 149-room hotel.	155 5th St, Huntington Beach	1.63	Completed
12	Beach Walk	173 multi-family apartment units within a 4-story building, a 5-level parking structure, public and private open space areas.	19891 & 19895 Beach Blvd, Huntington Beach	2.10	Completed

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
13	LeBard Park and Residential Project	9.7-acre surplus school site for public recreation and single-family residential uses.	20461 Craimer Ln, Huntington Beach	2.16	Approved
14	Truewind-Former Wardlow School Site	49 detached single-family residential units on an 8.35-acre site.	9191 Pioneer Dr, Huntington Beach	2.16	Under Construction
15	Brookhurst Street and Adams Avenue IIP	Widening of the Brookhurst St/Adams Ave intersection in all directions.	Brookhurst St and Adams Ave, Huntington Beach	2.38	Draft Environmental Impact Report (DEIR)
16	Lighthouse Project	89-unit (49 residential units, 40 live/work units), three-story mixed-use development. 332-space parking garage, 2aces of common open space.	1620-1644 Whittier Ave, Costa Mesa	2.42	Initial Study (IS)/Mitigated Negative Declaration (MND)
17	Ebb Tide Residential Project	Demolition of 73 mobile home spaces, three fixed structures and related surface improvements and the development of 81 single-family detached condominium units.	Placentia Ave and 16th St, Newport Beach	2.96	MND
18	Fairwind- Former Lamb School Site	80 detached single-family residential units on a 11.65-acre site	10251 Yorktown Ave, Huntington Beach	2.96	Under Construction
19	Westside Gateway Project	Seeking approval to redevelop a 9-acre project site with a mix of 177 dwelling units (residential lofts and live/work). Redevelopment includes demolition of all existing buildings and parking areas.	671 W. 17th St, Costa mesa	3.20	Under Construction
20	Beach and Ellis - Elan Mixed Use	274 units (26 studio, 123 one-bedroom, 6 live-work, 119 two-bedroom units of which 27 are affordable units) also includes: 8,500 sq. ft. commercial, 17,540 sq. ft. public open space and 31,006 sq. ft. residential private open space.	18502, 18508-18552 Beach Blvd, Huntington Beach	3.37	Under Construction

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
21	Newport Beach City Hall Reuse Project- Now called the "Lido House Hotel"	Four story, 130-room hotel set on a 4.25-acre site that formerly housed the Newport Beach City Hall.	3300 Newport Blvd, Newport Beach	3.45	IS/ND
22	2277 Harbor Boulevard Project	Proposal involves demolishing existing 236-room motel and the construction of a four-story, 224-unit luxury apartment project.	2277 Harbor Boulevard, Costa Mesa	3.50	IS/MND
23	Mesa Verde East Project	Demolition of existing site improvements and construction of a 10-unit, 2-story, detached residential development.	Adams Avenue & Mesa Verde Dr. East, Costa Mesa	3.69	Notice of intent to adopt negative declaration
24	Oceana Apartments	Four story apartment building with 78 affordable housing units for income levels at 30 to 60 percent of Orange County median income on 2-acre site.	18151 Beach Blvd, Huntington Beach	3.75	Under Construction
25	Bolsa Chica Roadway Embankment Reconstruction Project	Install pedestrian safety cable rails and metal beam guardrails along State Route 1 in Huntington Beach.	SR 1 (Pacific Coast Hwy) from Warner Ave to Seapoint Ave, Huntington Beach	3.95	IS/ND
26	Huntington Beach Senior Center	One-story senior center on an undeveloped portion of Central Park. Approximately 227 parking spaces will be provided for visitors and City vehicles.	Central Park (5-acre area; SW of the intersection of Goldenwest St and Talbert Ave)	4.14	Under Construction
27	Hyundai Motor America Corporate Campus Project	Expand existing corporate headquarters with a 469,000-sq. ft. campus	10550 Talbert Ave, Fountain Valley	4.39	Completed
28	Vision 2020 Facilities Master Plan	1,238,542 sq. ft. of academic, administrative, residential, and parking facilities on Orange Coast College campus.	2701 Fairview Rd, Costa Mesa	4.41	Unknown
29	Well #6 Colored Water Treatment Plant (WTP)	Construct WTP within the next two years.	Harbor Blvd at Gisler Ave,Costa Mesa	4.48	Unknown

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
30	Fountain Valley Civic Center Specific Plan	Build Ayres Hotel, 88 residential units (27 single-family, 61 townhomes), and 2,300 sq. ft. of retail space on 8.62-acres.	Brookhurst St and Slater Ave, Fountain Valley	4.64	Unknown
31	Costa Mesa High School Sports Complex	Construct sports complex with 997-seat bleachers, replacing existing track and field with synthetic field and rubber track, and provide various associated facilities.	2650 Fairview Rd, Costa Mesa	4.68	Unknown
32	Back Bay Landing Project	New reservoir foundation, install underground pipelines	East Coast Hwy at Bayside Dr, Newport Beach	4.76	Under review with California Coastal Commission
34	Warner-Nichols Project	Demolish six buildings	Warner Ave at Nichols Ln, Huntington Beach	4.92	Adopted
35	Beach Blvd and Warner Ave Intersection Improvement Project	Construct westbound right turn lane on Warner Ave at intersection and associated improvements including new 5 ft. wide, 15 ft. long sidewalk along west side of A Lane.	Intersection of Beach Blvd and Warner Ave, on the north side of Warner Ave from Beach Blvd to the alley between A Lane and B Lane, including portions of the adjacent commercial properties to the north at 16990 Beach Blvd, 8021 Warner Ave, and 8071 Warner Ave.	4.92	Adopted
37	Upper Newport Bay-East Bluff Drainage Repair Project	Drainage improvements and erosion repair within bluff on E side of Upper Newport Bay.	E of Back Bay Dr and W of Vista Del Oro, Newport Beach	5.37	Proposed
38	Yakult USA Manufacturing Facility	77,000 sq. ft. manufacturing facility on 8.8-acres.	17256 Newhope St, Fountain Valley	5.48	Completed
39	Parkside Estates	111 single-family residences; 23-acres preserved, restored and enhanced open space; 1.6-acre neighborhood park; public trails; and water quality treatment system.	W side Graham St, S of Warner Ave, along E Garden Grove Wintersburg Flood Channel 17221 (S of Greenleaf Ln), Huntington Beach	5.67	Planning

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
40	Ganahl Hardware Store and Lumber Yard	65,263 sq. ft. building materials store with administrative offices and 286 parking spaces.	Bristol St and Northbound Newport Blvd, Huntington Beach	5.74	Completed
41	Brightwater	347 single-family units and over 37-acres habitat restoration and trails.	Warner Ave and Los Patos Ave, Huntington Beach	5.77	Under Construction
42	Newport Executive Court Project	Project includes construction of two, 2-story medical office buildings and a 324-space surface parking lot on 4-acres.	Cross Streets: Birch St and Mesa Dr, Newport Beach	5.88	Plan Check
43	General Plan Update EIR (North Newport Center)	Increase the multi-family residential development allocation from 430 units to 524 units on 121-acres.	Newport Beach	5.89	Unknown
44	Monogram Apartments (Formerly Pedigo)	Four-story apartment building with 510 dwelling units and six-level, 862-space parking structure.	7262,7266,7280 Edinger Ave and 16001, 17091 Gothard St, Huntington Beach	5.96	Plan Check
45	The Boardwalk (Murdy Commons)	487 dwelling units and 14,500 sq. ft. of commercial area on a 12.5-acre site with 1/2 acre public park.	7441 Edinger Ave-Northeast corner of Edinger Ave and Gothard St (Former Levitz Furniture store site)	5.97	Under Construction. First two phases have opened for occupancy.
46	Edinger Walmart	100,865 sq. ft. vacant retail building within an existing commercial center.	SW corner of Goldenwest St and Edinger Ave, Huntington Beach	6.02	Completed
47	Airport Circle Residential Project	45-unit condominium subdivision with open space on 2.5-acre site. Site layout: 8 detached three-story buildings with 4 to 8 attached dwelling units.	16911 Airport Cir. Huntington Beach	6.04	Plan Check
48	The Village at Bella Terra	Costco Wholesale, with gasoline service station and mixed-use retail and residential project.467 multi-family residential units within four-story building.	7777 Edinger Ave, Huntington Beach	6.06	Completed

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
49	San Diego Freeway I-405 Improvement Project	One general-purpose lane in each direction on I-405 from Euclid St to the I-605 interchange, add tolled express lane in each direction of I-405 from SR-73 to SR-22 East.	I-405 between SR-73 & I-605, Costa Mesa, Seal Beach	6.06	Unknown
50	Huntington Beach Lofts	Five-story, 385-luxury residential units located above 10,000 sq. ft. of street level retail and commercial uses.	7302-7400 Center Ave, Huntington Beach	6.16	Under Construction
51	Vans Skate Park	Construction of a skate park.	7471 Center Ave, Huntington Beach	6.35	Completed
52	Wyndham Boutique Hotel/High-Rise Residential Project	Demolition of Wyndham Hotel parking garage and construction of a 100-unit condominium tower adjacent to a new 6.5-level parking garage with 1 subterranean level and 5.5 levels above ground.	3350 Ave of the Arts, Costa Mesa	6.53	Approved
53	Harmony Cove Marina Development	23-boat slip marina, eating and drinking establishment with outdoor dining area and alcoholic beverage sales, and ancillary uses to marina.	N side of Warner Ave, W of Weatherly Ln-Formerly Percy Dock	6.55	Proposed
54	OC-44 Pipeline Rehabilitation Project	Sip-line existing 42-inch pipeline with new 30-inch Ductile Iron Pipe (DIP). To accommodate these improvements, a pipe jacking operation would be conducted, requiring three access pits.	University Dr and La Vida, Newport Beach	6.61	Approved-Construction 2018-2020
55	Civic Center and Park Project	Construction of park, city hall building, and 450 parking spaces.	Avocado Ave and McArthur Blvd, Newport Beach	6.62	Unknown
56	Uptown Newport Village Specific Plan Project	Mixed-use project with 1,244 residential units, 11,500 sq. ft. retail, and a 2-acre park.	Jamboree Rd and Fairchild Rd, Newport Beach	6.92	Approved
57	Tennis Estates Tree Trimming and Management Plan	Tree Trimming and Management Plan for the Tennis Estates Homeowners Association property in the Coastal Zone.	16380 Wimbledon Ln, Huntington Beach	7.05	In Progress

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
58	Rofael Marina and Caretaker Facility	Construct marina on 6,179 sq. ft. property.	16926 Park Ave, Huntington Beach	7.12	In Progress. Requires Coastal Development Permit and a Conditional Use Permit.
59	Campus and Jamboree	1,600 residential units (5 to 6-story apartments), 17,000 sq. ft. plus primary retail in Irvine Technology Center, and up to 23,000 sq. ft. accessory retail and/or residential-serving amenities, 1-acre public park, and two 0.5-acre public plazas.	NW corner of Campus and Jamboree, Irvine	7.37	Phase 1 Under Construction (9/26/2015)
60	Mater Dei High School Parking Structure	Three-level parking structure	1202 W Edinger Ave, Santa Ana	7.80	Proposed, 3-5 years 2018 at earliest
61	Sunset/Huntington Harbour Maintenance Dredging and Waterline Installation Project	Maintenance dredging and waterline Installation.	Edinger Ave and Sunset Way, Huntington Beach	7.80	Unknown
62	Warner Avenue Widening	Widening to six lanes.	Warner Ave, Santa Ana	8.48	Approved. Construction in four phases. Phase 1 Jan. 2016 to Jan 2017.
63	2801 Kelvin	384-unit apartments.	2801 Kelvin Ave, Irvine	8.70	Under Construction. 18-month construction period

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
64	Bristol St. Widening	Widening to six lanes.	3.9-mile stretch of Bristol St from Memory Ln to Warner Ave, Santa Ana	8.79	Under Construction. Phase 1 complete out of four phases, Phase 2 out to bid with 11-month construction period. Phase 3 June 2015 to June 2016. Phase 4 currently unfunded.
65	Vista Verde	Build 55-unit project, which is proposing to add 3 additional units to the project	5144 Michelson Dr, Irvine	10.00	Unknown
66	Grand Avenue Widening	Widening to six lanes	Grand Ave, Santa Ana	10.15	Under Construction July 2015 to March 2016.
67	I-5 Central County Improvement Project	Add second carpool lane in each direction on I-5 between the SR-55 and the SR-57.	I-5 between SR-55 and SR-57, cities of Santa Ana, Tustin and Orange.	10.39	Approved. Construction Jan. 2016 to Jan 2017.
68	I-5, SR-73 to El Toro Road	Widen I-5 to accommodate general-purpose lanes in each direction. Reestablish existing auxiliary lanes. Extend second carpool lane from El Toro Rd. to Alicia Parkway in both directions and modify ramps as needed. Reconstruct Avery Parkway and La Paz Rd. interchanges. 2018 to 2022	I-5 between SR-73 to El Toro Rd, cities of Laguna Hills, Laguna Woods, Laguna Niguel, Mission Viejo, Lake Forest, and San Juan Capistrano.	10.67	Proposed
69	Alamitos Energy Center	Two natural gas turbine power blocks. Power Block 1:natural-gas-fired combustion turbine generators in combined-cycle configuration, two unfired heat recovery steam generators, one steam turbine generator, air-cooled	690 N Studebaker Rd, Long Beach	10.74	Application in review

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
		condenser, auxiliary boiler, related ancillary equipment.. Power Block 2: four simple-cycle combustion turbine generators with fin-fan coolers and ancillary facilities. 21-acre site within larger 71.1-acre Alamitos Generation Station site.			
70	Sexlinger Farmhouse & Orchard Residential Development Project	24 single-family homes on 5-acres.	E Santa Clara Ave at Tustin Ave, Santa Ana	11.38	On Hold, CEQA Lawsuit-Possible Appeal
71	Santa Fe Depot Specific Plan	Potential infill development at as many as 11 locations.	Between Walnut and Palmyra Aves, Orange	12.13	Unknown
72	Irvine Center Drive and Alton, NWC.	766-unit apartments.	Northwest corner of Irvine Center Dr and Alton Pkwy, Irvine	12.84	Under Construction. Estimated 24-month construction
73	Great Park Neighborhoods (Heritage Fields)	Residential housing, parks, and sports fields/complex.	Former El Toro Marine Air Station, Irvine	13.12	Unknown
74	Pacifica and Spectrum NWC	573-unit apartments	SW corner of Alton Pkwy and Spectrum, Irvine	13.19	Under Construction. 24-month construction
75	Cypress Community College AST	Construct storage tank.	9200 Valley View St, Cypress	14.25	Unknown
76	Recycled Water Distribution System Expansion	Build tertiary treatment facilities and transmission pipeline.	Ridge Route Dr & Moulton Pkwy, Laguna Hills and Laguna Woods	14.66	Approved
77	Coastal Treatment Plant Export Sludge Force Main Replacement	Replacement of 16,600 ft. of two 4-inch iron pipelines, eastern side of Aliso Creek.	Aliso Viejo, Awma Rd at Alicia Pkwy, Laguna Niguel	15.61	Unknown
78	ND-12-02 Aliso Creek Pedestrian Bridge/Service Road	Replace pedestrian bridge with new build.	Laguna Woods	15.91	Unknown
79	Radha Raman Vedic Mandir	Church renovation and additional construction of facilities.	1022 N Bradford Ave, Placentia	17.54	Unknown

Label ID#	Project Title	Description	Location	Distance to Project (Miles)	Status
80	Robert Diemer Filtration Plant Improvements	New reservoir foundation, install underground pipelines	3972 Valley View, Yorba Linda	19.62	Completed
81	I-5 between Avenida Pico to San Juan Creek Road	Add carpool lane both directions on I-5 between Avenida Pico to San Juan Creek Road. Reconstruct interchange at Avenida Pico. Widen northbound Avenida Pico on-ramp to three lanes. Provide dual left-turn lanes to both northbound and southbound Avenida Pico on-ramps. Add sound walls where needed.	I-5 between Avenida Pico and San Juan Creek Rd, San Clemente, San Juan Capistrano and Dana Point.	21.14	Under Construction 2013 to 2017.

ENVIRONMENTAL JUSTICE

The California Resources Agency recognizes that environmental justice (EJ) communities are commonly identified as those where residents are predominantly minorities or live below the poverty level; where residents have been excluded from the environmental policy setting or decision-making process; where they are subject to a disproportionate impact from one or more environmental hazards; and where residents experience disparate implementation of environmental regulations, requirements, practices, and activities in their communities. Environmental justice efforts attempt to address the inequities of environmental protection in these communities.

An EJ analysis is composed of the following:

- Identification of areas potentially affected by various emissions or impacts from a proposed project;
- Providing notice in appropriate languages (when possible) of the proposed project and opportunities for participation in public workshops to EJ communities;
- A determination of whether there is a significant population of minority persons, or persons below the poverty level, living in an area potentially affected by the proposed project; and
- A determination of whether there may be a significant adverse impact on a population of minority persons or persons below the poverty level caused by the proposed project alone, or in combination with other existing and/or planned projects in the area.

California law defines EJ as “the fair treatment of people of all races, cultures and income with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.”[7] All departments, boards, commissions, conservancies and special programs of the Resources Agency must consider EJ in their decision-making process if their actions have an impact on the environment, environmental laws, or policies. Such actions that require EJ consideration may include:

- adopting regulations;
- enforcing environmental laws or regulations;
- making discretionary decisions or taking actions that affect the environment;
- providing funding for activities affecting the environment; and
- interacting with the public on environmental issues.

[7] (Gov. Code §65040.12; Pub. Resources Code, §§ 71000-71400

DEMOGRAPHIC SCREENING ANALYSIS

As part of its CEQA analysis for the Application for Certification for the HBEP, Energy Commission staff used 2010 U.S. Census data to identify the minority populations and the most recent U.S. Census data from the American Community Survey (ACS) to identify below-poverty level populations within the six-mile radius of the HBEP[8]. The demographic screening is based on *Environmental Justice: Guidance Under the National Environmental Policy Act* (CEQ, 1997) and *Guidance for Incorporating Environmental Justice Concerns in EPA's Compliance Analyses* (US EPA, 1998), which provides staff with information on outreach and public involvement.

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

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

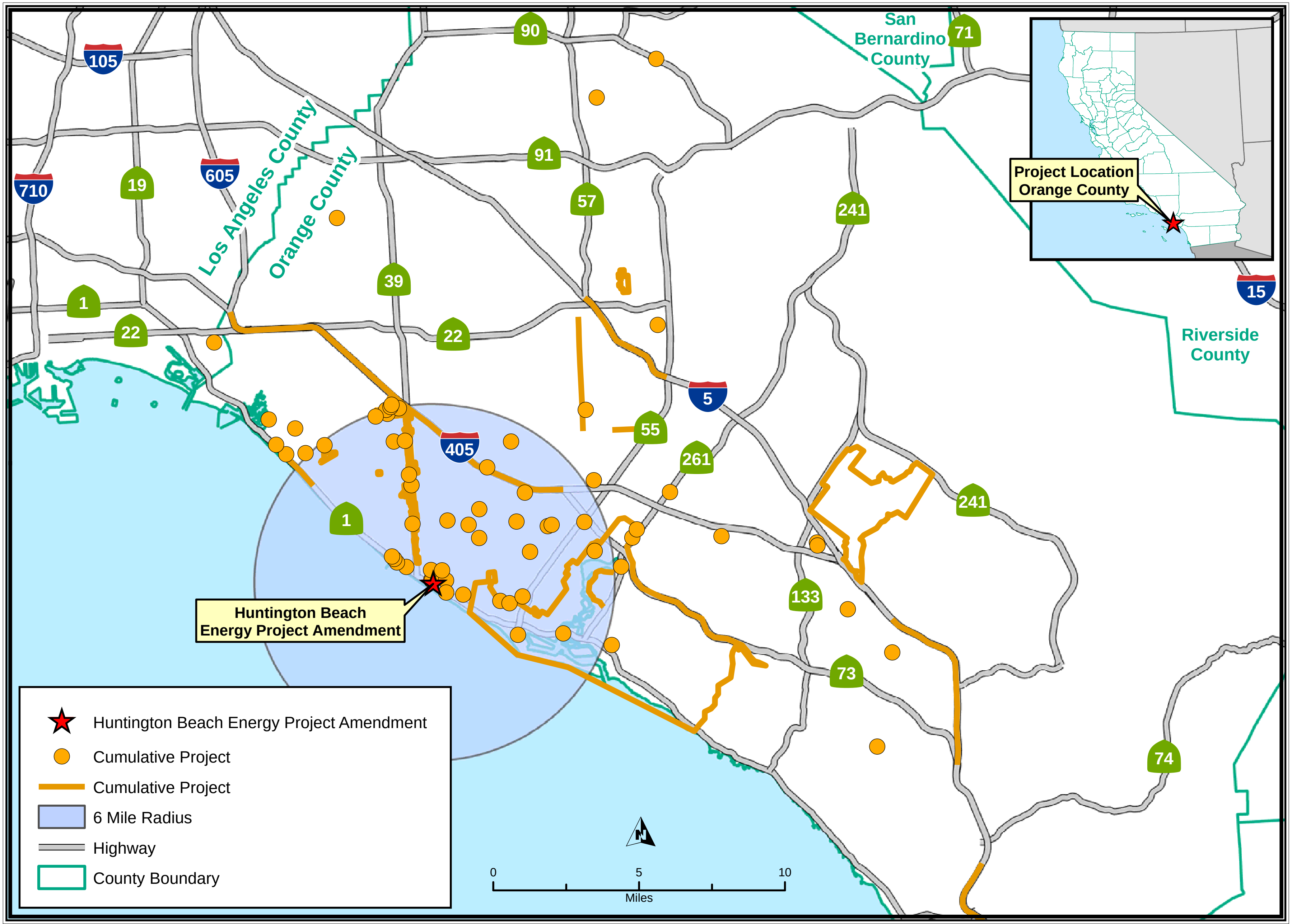
ADDITIONAL ENVIRONMENTAL JUSTICE POPULATION CONSIDERATIONS

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

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

EXECUTIVE SUMMARY - FIGURE 1

Huntington Beach Energy Project Amendment - Cumulative Projects Map



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: California Energy Commission, Open Street Map

INTRODUCTION

Testimony of John Heiser, AICP

PURPOSE OF THIS REPORT

This Final Staff Assessment (FSA) Part 2 is the California Energy Commission staff's independent analysis of the proposed Huntington Beach Energy Project (HBEP) Petition to Amend (PTA). This FSA Part 2 is a staff document. It is neither a Committee document, nor a draft decision. The FSA describes the following:

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

The FSA Part 2 will include staff's final evaluation of Air Quality and Public Health impacts of the amended HBEP.

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

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

ORGANIZATION OF THE FINAL STAFF ASSESSMENT

The FSA Part 2 contains the Executive Summary, Introduction, Project Description, and Air Quality and Public Health. The Air Quality and Public Health chapters contain the environmental and engineering analyses of the proposed project. These chapters are followed by a list of staff that assisted in preparing this report.

Included in the 2 technical area assessments are discussions of:

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

ENERGY COMMISSION SITING PROCESS

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

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

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

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

Staff received comments from the petitioner and the city of Huntington Beach on the FSA Part 1. Staff provided supplemental testimony in response to these comments which has been incorporated in the FSA Part 2. A Prehearing Conference was held at the Energy Commission on 11/14/16 on Part 1. A Prehearing Conference and Evidentiary Hearing for Part 1 and Part 2 is scheduled for 12/21/16.

The FSA is only one piece of evidence that will be considered by the Committee (comprising two Energy Commission Commissioners who have been assigned to oversee the review this project) in reaching a decision on whether or not to recommend that the full Energy Commission approve the proposed project. At the public evidentiary hearings, all parties will be afforded an opportunity to present evidence and to rebut the testimony of other parties, thereby creating a hearing record on which a decision on the project can be based. The hearing before the Committee also allows all parties to argue their positions on disputed matters, if any, and it provides a forum for the Committee to receive comments from the public and other governmental agencies.

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

AGENCY COORDINATION

As noted above, the Energy Commission certification is in lieu of any permit required by state, regional, or local agencies and federal agencies to the extent permitted by federal law (Pub. Resources Code, § 25500). However, the Commission staff typically seeks comments from, and works closely with, other regulatory agencies that administer LORS that are applicable to proposed projects. The agencies associated with the HBEP amendment include the U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, U.S. Army Corps of Engineers, California Coastal Commission, State Water Resources Control Board/Regional Water Quality Control Board, California Department of Fish and Wildlife, Caltrans, the California Air Resources Board, the South Coast Air Quality Management District, the city of Huntington Beach and the Huntington Beach Fire Department.

OUTREACH

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

LIBRARIES

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

On June 24, 2016, Energy Commission staff sent the HBEP amended PSA to libraries in Huntington Beach, Santa Ana, Costa Mesa, Fountain Valley, Seal Beach, Eureka, Sacramento, Fresno, San Francisco, Los Angeles and San Diego.

On October 17, 2016, Energy Commission staff sent the HBEP amended FSA Part 1 to libraries in Huntington Beach, Santa Ana, Costa Mesa, Fountain Valley, Seal Beach, Eureka, Sacramento, Fresno, San Francisco, Los Angeles and San Diego.

On December 12, 2016, Energy Commission staff sent the HBEP amended FSA Part 2 to libraries in Huntington Beach, Santa Ana, Costa Mesa, Fountain Valley, Seal Beach, Eureka, Sacramento, Fresno, San Francisco, Los Angeles and San Diego.

INITIAL OUTREACH EFFORTS

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

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

Energy Commission regulations require staff to notice, at a minimum, property owners within 1,000 feet of a project and 500 feet of a linear facility (such as transmission lines, gas lines, and water lines). This was done for the project. Staff's ongoing public and agency coordination activities for this project are discussed under the Public and Agency Coordination heading in the Executive Summary section of the amended PSA.

ENVIRONMENTAL JUSTICE

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

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

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

PROJECT DESCRIPTION

John Heiser, AICP

INTRODUCTION

The Final Staff Assessment (FSA) Part 2 for the Petition to Amend (PTA) the 2014 Energy Commission Final Decision (Decision) for the Huntington Beach Energy Project (HBEP) contains the analyses of potential environmental effects and engineering factors associated with the development and operation of the project in two technical areas. The HBEP footprint is located within the existing operating Huntington Beach Generating Station located in Huntington Beach, California at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (Highway 1) and Newland Street.

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

The FSA Part 2 includes staff's final evaluation of, and proposed mitigation for, Air Quality and Public Health impacts of the amended HBEP.

PROJECT SETTING, LOCATION AND SITE DESCRIPTION

On June 27, 2012, AES Southland, LLC, submitted an Application for Certification (AFC) for the HBEP. On October 29, 2014, the Energy Commission approved the AFC for HBEP (12-AFC-02) with the Final Decision. On September 4, 2015, AES Southland LLC[1] submitted the PTA.

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

[1] AES Southland LLC is now known as AES Huntington Beach Energy, LLC, which is an indirect wholly-owned subsidiary of the AES Corporation

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

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

The necessity to amend the Decision is the result of the selection by SCE of the revised AES project in the 2013 Local Capacity Requirements Request for offers to provide 644 MW of nominal capacity, with different technology than that permitted in the HBEP Final Decision. The second phase: two LMS-100 PB combustion turbine generators, is currently not under a Power Purchase Agreement (PPA). However, AES is requesting to license these turbines as part of the current PTA proceeding.

Based on this selection by SCE, the PTA would amend the Decision to allow for construction and operation of the HBEP with the following equipment:

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

PROJECT DESCRIPTION

The project owner, AES Huntington Beach Energy, LLC, proposes to modify the design of the HBEP in order to construct and operate an 844-megawatt (MW) power plant. Construction would commence in two phases with the first phase consisting of a natural gas-fired, combined-cycle, air-cooled, 644-MW electrical generating facility. After the first phase combined-cycle power block is operational, phase 2 would begin with adding two 100 MW simple-cycle gas turbines (SCGT).

No new offsite linear facilities are proposed as part of this project which would be located on 30 acres (28.6 acres approved in the Decision, plus an additional 1.4 acres of paved area AES acquired from Southern California Edison (SCE)).

As part of the amendment, a total of 22 acres of combined construction parking and construction laydown area is proposed at the Plains All-American Tank Farm site. The Plains All-American Tank Farm is located east of HBGS, next to the Huntington Beach Channel, adjacent to the Huntington Beach Wetland Preserve/Magnolia Marsh wetlands and to Magnolia Street. The Plains All-American Tank Farm appears to have been built between 1963 and 1972. The nearly 30-acre site comprises three storage tanks, a pump house and a valve/manifold structure. It is surrounded by a vegetated earthen containment berm. Each tank is located within a shallow retention basin. The licensed HBEP included approximately 1.9 acres of construction parking on the Plains site.

The owner of the Plains All-American Tank Farm site has received a permit from the city of Huntington Beach to remove the storage tanks and grade the site for future, undisclosed development. Access to the tank farm would be from Magnolia Avenue and Banning Street. The project owner is working with the city of Huntington Beach to install a temporary signalized site access road at the intersection of Magnolia Avenue and Banning Street. The access road would be graveled in the areas used for equipment laydown and parking to reduce dust and manage stormwater. The project owner will be required to work with the city of Huntington Beach to acquire the proper permits for site grading and temporary use of the Plains All-American Tank Farm during the demolition and construction activities of the amended project.

The construction of Power Block 1 would require the removal of the existing Unit 5 peaker (former gas turbine generator). The initial demolition activities for the Unit 5 peaker would include demolishing the foundations, building, small auxiliary mechanical and electrical equipment, and removal of the fuel storage tanks per the requirements of a Department of Toxic Substances Control Removal Action. The demolition activities of Unit 5 would include the removal of two former fuel oil tanks, associated fuel oil pipelines, asbestos, several support buildings, and containment berms. The demolition activities are scheduled for the 1st quarter of 2016 to the 2nd quarter of 2017. The demolition activity of the Unit 5 peaker was approved by the Energy Commission in the October 2014 Decision. All of the above demolition activities are addressed in the PTA for review of potential project cumulative impacts.

Removal/demolition of existing Huntington Beach Generating Station Units 3 and 4 would occur in advance of the construction of the Amended HBEP phase 2 SCGT power block. Demolition to remove Units 3 and 4 is anticipated to begin during the 2nd quarter of 2020 and continue through the 2nd quarter of 2022 (TN# 210969, Table 5.1A.60). Existing Huntington Beach Generating Station Units 3 and 4 are licensed through the California Energy Commission (CEC; 00-AFC-13C). Demolition of these units authorized under that license would proceed during the amended HBEP certification process, and is not part of the amended (12-AFC-02C) HBEP project definition.

Existing Huntington Beach Generating Station Unit 1 would be retired in the fourth quarter of 2019 to provide interconnection capacity for the new CCGT units. Unit 2 would be retired either after commercial operation of the HBEP SCGT units or at the final compliance deadline for once-through-cooling intake structures as determined by the State Water Resources Control Board, after which demolition of Huntington Beach Generating Station Units 1 and 2 would commence. The amendment petition indicates the demolition of Units 1 and 2 would occur during the 1st quarter of 2024 through the 4th quarter of 2025. The PTA describes under Section 2.2 "Demolition Activities", the demolition of these units 1 and 2 would include their ancillary mechanical and electrical equipment down to the concrete super structure or turbine deck level. Recently, per opening testimony TN# 214211 docketed by the applicant, indicated the removal of Units 1 and 2 to grade. The existing reverse osmosis/electrodeionization tanks that are currently in use would remain in service as part of the Licensed HBEP.

The planned construction and demolition activities of the amended HBEP would occur on a schedule that allows continued operation of the existing HBGS power generation and synchronous condensers to maintain power delivery and grid reliability during construction of the new facilities. The demolition work would require site preparation and grading activities. **Project Description - Figure 1** and **Project Description - Table 1** depict the various demolition and construction phases on the HBGS site.

Project Description - Table 1
Demolition / Construction Activity Timeline

Demolition / Construction Activity	Timeline
Demolish Unit 5 and fuel tanks	Q1 2016 - Q2 2017 16 months
Construction Power Block 1	Q2 2017 – Q2 2020 36 months
Commercial Operation Power Block 1	Q2 2020
Demolish Units 3, 4 (under separate approved License and not part of the current amended project)	Q2 2020 – Q2 2021 12 months
Construction Power Block 2	Q1 2022 – Q4 2023 24 months
Commercial Operation Power Block 2	Q1 2024
Demolish Units 1 and 2 to grade	Q1 2024 – Q4 2025 24 months

If the Amendment to the Decision is approved by the Energy Commission, construction and demolition activities at the project site are anticipated to take approximately 9 years, lasting through the fourth quarter of 2025. The amended application indicated a construction schedule for the various phases of activities with the CCGT phase I, Power Block 1, anticipated beginning in the second quarter of 2017 with commercial operation of Power Block 1 during the second quarter of 2020. Construction of the SCGT phase 2, Power Block 2, is anticipated to begin during the first quarter of 2022 with commercial operation during the first quarter of 2024.

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

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

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

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

Project Description - Figure 2 with both onsite and offsite locations. The amended parking areas and locations: A new entrance to the Plains All American Tank Farm would be from a modified intersection at the existing Magnolia Street and Banning Avenue signalized intersection. **Traffic and Transportation** Conditions of Certification **TRANS-4**, **TRANS-8** and **TRANS-9** would require improvements for the current three-way signalized intersection to temporarily convert it to a four-way signalized intersection, and for the project owner to comply with the city of Huntington Beach's requirements for coastal zone parking.

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

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

No offsite linear developments are proposed as part of this project. The amended HBEP would connect the 844 MW of electricity through two overhead 230-kilovolt (kV) generation ties connecting each power block to the existing onsite SCE Ellis switchyard. Natural gas is delivered to the HBGS via an existing SoCal Gas16-inch diameter line to an existing gas metering station. As part of the HBEP project, a new gas metering station and new gas pressure control station would be constructed.

APPLICANT'S PROJECT PURPOSE AND OBJECTIVES

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

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

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

PROJECT FEATURES

Project features would consist of a 30-acre power plant site, which would require both onsite and offsite laydown and construction parking. Approximately 22 acres of construction laydown would be required, and a maximum of 300 parking sites. The power plant, transmission lines, SCE switchyard, and natural gas connection, are located within the city of Huntington Beach within an area designated as Public, in which the Huntington Beach General Plan permits development of public utilities.

Project Description - Figure 3, shows the general arrangement and layout of the proposed facility. The Visual Resources section of this PSA includes a number of visual simulations of the proposed project, before and after construction. The existing HBGS currently has five units (units 1, 2, 3, 4, and the Unit 5 peaker). Units 1 and 2 are currently operational; Units 3 and 4 are owned by Edison Mission Huntington Beach, LLC. Effective October 31, 2012, Units 3 and 4 ceased commercial operation, and the air emission credits transferred to the Walnut Creek Energy Park, a 500 MW generating facility located in City of Industry, California. On September 7, 2012, the California ISO approved a must-run contract on units 3 and 4 to convert to synchronous condensers to provide voltage support to southern Orange County and San Diego in response to the San Onofre Nuclear Generating Station Units 2 and 3 being shut down. An amendment was approved by the Energy Commission on December 7, 2012, to convert units 3 and 4 to synchronous condensers which provide voltage support. Unit 5, a 133 MW peak demand facility, was retired in 2002.

Two 230- kV transmission interconnections would connect HBEP Power Blocks 1 and 2 to the existing onsite SCE Ellis switchyard.

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

Natural gas is delivered via an existing SoCal Gas16-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 by the project owner.

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

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

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

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

The construction laydown areas consist of 6 acres at the HBGS, 22 acres of combined parking and laydown at the Plains All American Tank Farm, and 16 acres at the Alamitos Generating Station (AGS) in Long Beach, which would be used for component storage only; no assembly of components would take place at the AGS site. During construction, the large components would be hauled from the construction laydown area at the AGS site to the HBEP site as they are needed for installation.

In addition to the parking facilities described above, the construction laydown area at the Plains All American Tank Farm site would be used to park 35- to 75-ton rubber-tired cranes, excavators with shear attachments, backhoes, paving breaker attachments, front-end loaders, 10-wheeled dump truck for transporting materials, truck tractor driven end-dumps for transporting waste material to appropriate disposal facilities, fork lifts, compactors, bull dozers, water trucks used for dust control, fueling/service vehicles and pick-up trucks. The actual equipment may vary depending on the selected demolition contractor.

The construction materials at the Plains All American Tank Farm have been addressed in the PTA as well as the project owner's response to the comment letter from the Huntington Beach Wetlands Conservancy (TN# 211411) docketed on May 9, 2016. The construction laydown activities would include loading and unloading and stacking of construction supplies, preparation and cutting of materials for transport to the HBEP site, and temporary warehousing of material in mobile trailers. Welded assembled items would be transported by truck from the laydown area to the HBEP site via Magnolia to PCH to Newland. These transported assemblies could be oversized loads. The power turbines, generators, generator step-up transformers, and HRSG modules would arrive by ship or rail at the Port of Long Beach. The large components of the generating units would be hauled directly to the HBEP site for immediate installation. In the event that the heavy equipment arrives but cannot be transported and transferred to the HBEP site, it would be hauled to the Plains All American Tank Farm site. Additional storage space for heavy haul deliveries is also available at the AES Alamitos generating station.

During peak demolition activities at the site, an estimated maximum of 15 tractor-trailer units would leave the site each day to transport waste and debris offsite for salvage, recycle or disposal. It is anticipated that the demolition activities would be conducted during a 10-hour day, six-days a week, using a single shift. However, during critical demolition activities, longer work shifts and additional days would be needed.

The schedule for construction activities is based on a single, 10-hour shift six-days a week. Overtime and additional shift work may be required to maintain or enhance the construction schedule. The hours of construction activities would be from 7:00 a.m. to 8:00 p.m. with additional hours as needed. During the commissioning and startup phase of each power block, some activities may continue 24-hours per day, 7 days a week.

The delivery of fill material required to build the CCGT power block is expected to occur over a 10-month period with an average of 10 trucks per day during a 10-hour work shift six days a week.

See **Noise and Vibration** Section, Condition of Certification **NOISE-6**, regarding limiting construction-related activities to comply with city LORS and see the **Supplemental Testimony** on Noise regarding additional conditions addressing construction hours of operations.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Written comments on the Project Description section of the amended HBEP Final Staff Assessment (FSA) were submitted by Stoel Rives, LLP, on behalf of the project owner (Stoel Rives 2016nn), The city of Huntington Beach also provided comments on the FSA Part 1 related to land use (CHPWD 2016e).

AES HUNTINGTON BEACH ENERGY, LLC

Comment: *Project Owner concurs with Staff's Project Description set forth in the FSA. Project Owner clarified the plan for demolition of Units 1 and 2 to grade (TN# 214211).*

Response: Staff has reflected the change of Units 1 and 2 to be demolished to grade in the Project Description and updated Table 1.

CITY OF HUNTINGTON BEACH

Comment: *Page 3-3 Project Description: Use of Plains All-American Tank Farm site for project construction parking, laydown area and grading has not received City approvals.*

Response: Staff has incorporated the request from the city in the **Project Description** section,

Comment: *Page 3-4 Project Description: Demolition of Units 1 and 2 remains unclear regarding the demo of these units to grade.*

Response: The project owner provided clarification that Units 1 and 2 will be demolished to grade. (TN# 214211). Staff has incorporated the comment in the **Project Description** section.

Comment: *Page 3-6 Project Description: Traffic Impact Assessment is required to evaluate the proposed new intersection improvements at Magnolia and Banning.*

Response: Staff has provided language and conditions of certification in the Traffic and Transportation section of FSA Part 1 and in the supplemental testimony attached in FSA Part 2. Staff has summarized these changes in the **Project Description** section.

Comment: *Page 3-9 Project Description: Use of Plains All American Tank Farm with equipment parking, operations, and construction laydown areas. The FSA concludes that noise from the equipment, operations and material assembly on 22 acres is the same as construction worker parking on the previously approved decision of 1.9 acres. The FSA Part 1 does not provide any background analysis to support this conclusion.*

Response: Staff has provided language and conditions of certification in the **Noise and Vibration** section of FSA Part 1 and in the supplemental testimony attached in FSA Part 2. Staff has summarized these changes in the Project Description section.

Comment: *Page 3-9 Project Description: Concerns over construction activities and noise with hours and number of days including Federal Holidays. The City is requesting that restrictions be placed on the hours of construction activities and days of operations that meet city LORs.*

Response: Staff has provided language and conditions of certification in the **Noise and Vibration** section of FSA Part 1 and in the supplemental testimony attached in FSA Part 2. Staff has summarized these changes in the **Project Description** section.

NOTEWORTHY PUBLIC BENEFITS

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

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

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

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

REFERENCES

AES Huntington Beach. LLC (AES). Application for Certification, AES Huntington Beach Generating Station Retool Project Application for Certification, Huntington Beach, California (00-AFC-13). Filed with the California Energy Commission, December 1, 2000.

HBEP 2012a - AES Southland Development, LLC / Stephen O'Kane (TN 66003). Application for Certification (AFC), Volume I & II, dated, 06/27/2012. Submitted to CEC/Dockets on 06/27/2012.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

HBEP 2016d - Project Owner's Response to City of Huntington Beach Comments on PTA (TN 210262). Submitted to CEC/Docket Unit on February 10, 2016.

HBEP 2016n - AES Southland Development, LLC/Stephen O'Kane (TN 210969). Petition to Amend (12-AFC-02C) Revised Air Quality and Public Health Assessment, dated April 6, 2016. Submitted to John Heiser/CEC/Docket Unit on April 6, 2016

HBEP 2016p - Stoel Rives LLP/Kristen T.Castanos (TN 211411). Letter to John Heiser Re: Petition to Amend (12-AFC-02C) Response to Wetlands Conservancy, dated May 9, 2016. Submitted to John Heiser/CEC/Docket Unit on May 9, 2016

HBEP 2016cc - Stoel Rives LLP/Kristen T. Castanos (TN 212379).Petition to Amend - Project Owner's Comments on the Preliminary Staff Assessment, dated July 21, 2016. Submitted to John Heiser/CEC/Docket Unit on July 21, 2016.

HBEP 2016ff - Stoel Rives LLP/Judith Warmuth (TN 212752).Petition to Amend - Project Owner's Response to City of Huntington Beach Comments on the Preliminary Staff Assessment, dated August 11, 2016. Submitted to CEC/Docket Unit on August 11, 2016.

HBEP 2016nn - Stoel Rives LLP/Melissa A. Foster, Kristen T. Castanos (TN 214211). Applicant's Opening Testimony and comments for FSA Part 1 Evidentiary Hearing, dated October 27, 2016. Submitted to CEC/Docket Unit on October 27, 2016.

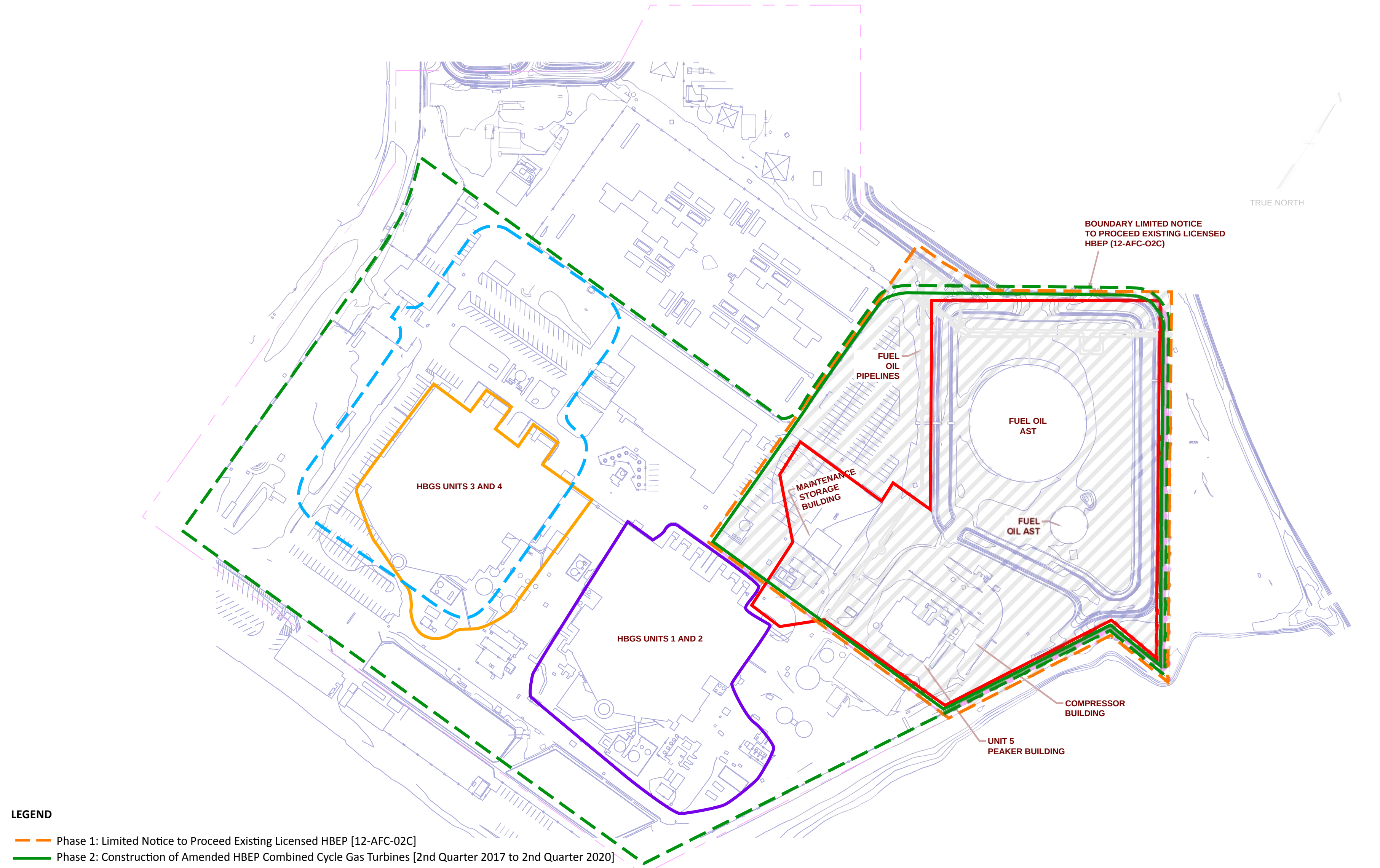
HBEP 2016ss - CH2M HILL/Jerry Salamy (TN 214577). Email Correspondence re: Demolition Schedule for Generating Station Units 3 and 4, dated November 29, 2016. Submitted to CEC/ Docket Unit on November 29, 2016.

CHB 2016b - Huntington Beach Department of Planning and Building/Jane James (TN 212437).City of Huntington Beach Comments Regarding Preliminary Staff Assessment for the Huntington Beach Energy Project Petition to Amend Docket No.12-AFC-02C, dated July 22, 2016. Submitted to John Heiser/CEC/Docket Unit on July 25, 2016

CHPWD 2016e - Huntington Beach Department of Community Development (TN 214618). Comments regarding final Staff Assessment Part 1, dated December 1, 2016. Submitted to CEC/Docket Unit on December 2, 2016.

PROJECT DESCRIPTION - FIGURE 1

Executive Summary - Phases of Amended Huntington Beach Energy Project



LEGEND

- Phase 1: Limited Notice to Proceed Existing Licensed HBEP [12-AFC-02C]
- Phase 2: Construction of Amended HBEP Combined Cycle Gas Turbines [2nd Quarter 2017 to 2nd Quarter 2020]
- Phase 3: Demolition of HBGS Units 3 and 4 prior to construction of Amended HBEP Simple Cycle Gas Turbine Units [Separate License 00-AFC-13C included as cumulative project]
- Phase 4: Construction of Simple Cycle Gas Turbines [1st Quarter 2022 through 4th Quarter 2023]
- Phase 5: Retirement of HBGS Unit 1 [4th Quarter 2019.] Retirement of HBGS Unit 2 after commercial operations of HBEP SCGT, or at nal deadline for once-through-cooling intake structures. [Voluntary Demolition of Units 1 and 2 to Turbine Deck 1st Quarter 2024 through 4th Quarter 2025]
- LNTP boundary
- Amended HBEP Site

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: CH2MHill

PROJECT DESCRIPTION - FIGURE 2

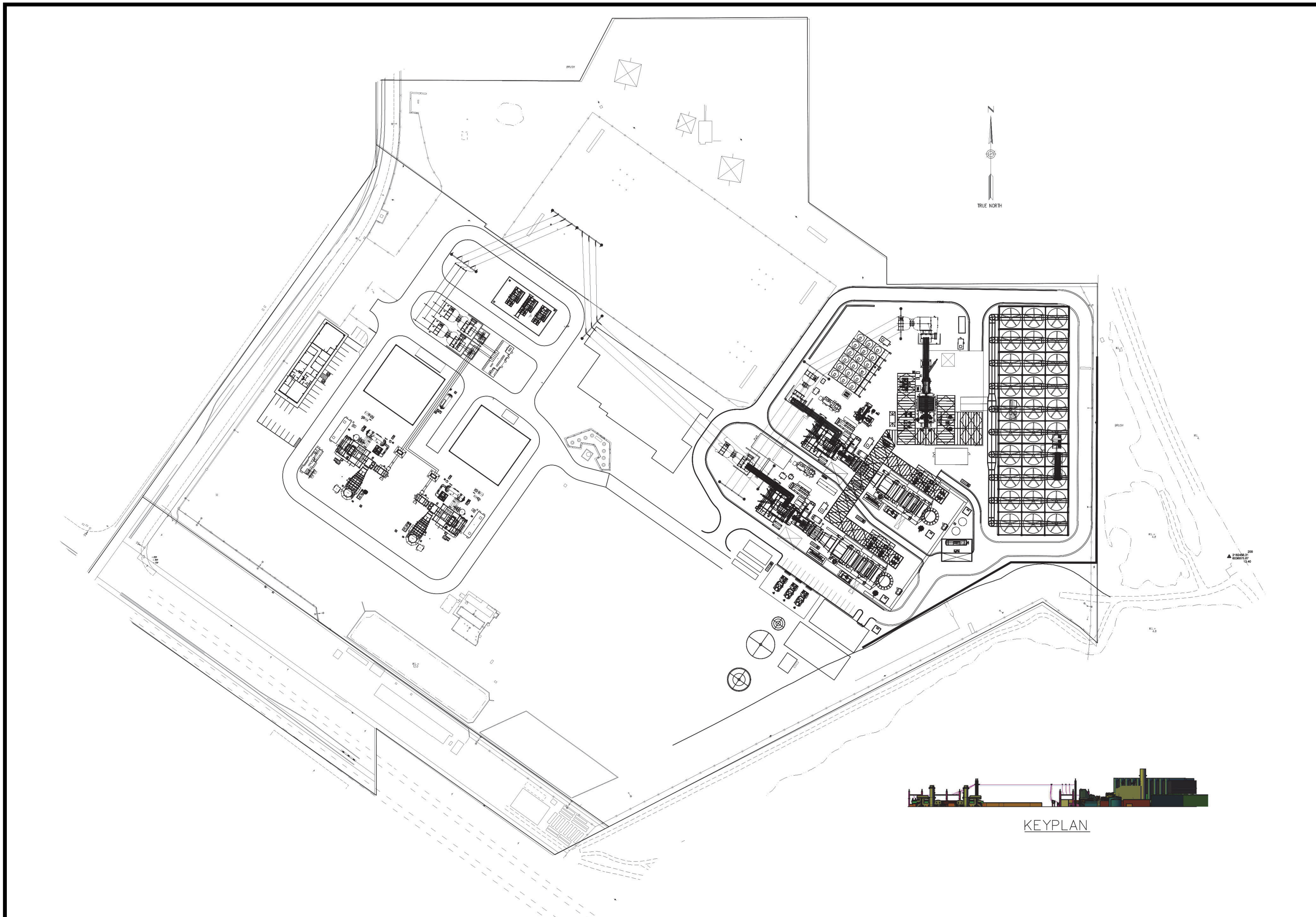
Amended Huntington Beach Energy Project - Construction / Laydown Parking Areas

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

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

PROJECT DESCRIPTION - FIGURE 3

Huntington Beach Energy Project - General Arrangement/Site Plan



SOURCE: CH2MHill

Environmental Assessment

AIR QUALITY

Testimony of Wenjun Qian, Ph.D., P.E.

SUMMARY OF CONCLUSIONS

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

The proposed modifications include changing the turbine technology in one combined-cycle power block from Mitsubishi Heavy Industries 501DA three-on-one turbines to GE 7FA.05 two-on-one turbines with a nominal capacity of 644 megawatts (MW) net with an auxiliary boiler. The other power block would be changed to two GE LMS-100PB simple-cycle turbines with a nominal combined capacity of 200 MW.

Staff's air quality analysis is based upon the thorough LORS analysis conducted by SCAQMD. They evaluated the Amended HBEP relative to baseline ambient air quality conditions, and staff incorporated the SCAQMD's conditions as mitigation measures for the Amended HBEP. Staff concludes that operating period mitigation would be provided in the form of Regional Clean Air Incentives Market (RECLAIM) Trading Credits (RTCs) and emission reduction credits (ERCs) as required by SCAQMD rules and that these measures would fully mitigate emissions of all nonattainment pollutants and their precursors. These mitigation measures reduce potential operational impacts of the proposed project to less than significant. While the proposed project modifications constitute a considerable change in fact and circumstance from the project as licensed, there are no new significant environmental effects or a substantial increase in the severity of previously identified significant effects associated with those modifications. Therefore, in accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Energy Commission Final Decision is necessary for Air Quality.

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

Condition of Certification **AQ-SC6** according to the revised construction emissions, which would be less than those for the licensed HBEP.

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

The proposed GE 7FA.05 combined-cycle turbines are expected to comply with the federal Standards of Performance for Greenhouse Gas Emissions (or Clean Air Act section 111[b]) of 1,000 pounds of carbon dioxide per gross megawatt hour (lb CO_2/MWh, gross) or (1,030 lb CO_2/ MWh, net) for new base load natural gas fueled turbines. The proposed GE LMS-100PB simple-cycle turbines are expected to comply with the limit of 120 lb CO_2 per million Btus (MMBtu) of natural gas heat input for new non-base load natural gas fueled turbines. Should the combined-cycle turbines operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. No specific GHG conditions of certification are proposed in the **Appendix AIR-1**, but **AQ-15** and **AQ-61** would ensure compliance with the new federal standards.

INTRODUCTION

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

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

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

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

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

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

SUMMARY OF THE DECISION

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

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

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

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

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

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

Applicable LORS	Description	Complies?	Basis of Compliance
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.	Yes	See more details in the text below.
Title 40 CFR Part 52 (Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of pollutants that occur at ambient concentrations that attain the National Ambient Air Quality Standards (NAAQS). The emissions of CO and NOx of the Amended HBEP would exceed the 100 tons per year (tpy) threshold per pollutant, thus the Amended HBEP would be subject to PSD analysis requirements for CO and NOx. The Amended HBEP would also be a	Yes	See more details in the text below.

Applicable LORS	Description	Complies?	Basis of Compliance
	new major stationary source of GHG (exceeding 100,000 tons per year) which requires a PSD permit for GHGs. The PSD program was initially within the jurisdiction of the U.S. EPA. On January 9, 2013, SCAQMD became the agency responsible for the issuance of GHG PSD permits for sources within the SCAQMD.		
Title 40 CFR Part 60, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)	Applies to steam generating units with design heat input rates between 10 and 100 MMBtu/hr that were installed after June 9, 1989. The proposed 71 MMBtu/hr auxiliary boiler would be subject to this regulation.	Yes	See more details in the text below.
Title 40 CFR Part 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)	New Source Performance Standard (NSPS) for Stationary Combustion Turbines greater than 850 MMBtu/hr: 15 parts per million (ppm) of NOx at 15 percent O_2 (0.43 lbs/MWh), 0.90 lbs/MWh of SOx discharge into the atmosphere, or the fuel contains total potential sulfur emissions of 0.060 lbs/MMBtu heat input.	Yes	See more details in the text below.
Title 40 CFR Part 64 (Compliance Assurance Monitoring [CAM])	The CAM regulation applies to emission units at major stationary sources required to obtain a Title V permit, which use control equipment to achieve a specified emission limit and which have emissions that are at least 100 percent of the major source thresholds on a pre-control basis. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits.	Yes	See more details in the text below.
Title 40 CFR Part 72	Acid Rain Program. Requires reductions in NOx and SO_2 emissions, implemented through the Title V program.	Yes	See more details in the text below.
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.	Yes	See more details in the text below.
H&SC §40910-40930	Permitting of source needs to be consistent with approved clean air plan.	Yes	The SCAQMD Final Determination of Compliance (FDOC) and staff's analysis would ensure compliance with LORS and thus would meet this requirement.

Applicable LORS	Description	Complies?	Basis of Compliance
California Public Resources Code §25523(a); 2300-2309 (CEC & ARB Memorandum of Understanding)	Requires that Energy Commission decision on an application for certification include requirements to assure protection of environmental quality. The Petition to Amend (PTA) is required to include information concerning air quality protection.	Yes	The proposed conditions of certification would ensure compliance with this LORS.
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.	Yes	The proposed conditions in the FDOC would ensure compliance with this LORS.
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.	Yes	See more details in the text below.
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.	Yes	See more details in the text below.
Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	This rule applies to boilers, steam generators, and process heaters of equal to or greater than 5 million Btu per hour rated heat input capacity used in all industrial, institutional, and commercial operations with the exception of: (1) boilers used by electric utilities to generate electricity; and (2) boilers and process heaters with a rated heat input capacity greater than 40 million Btu per hour that are used in petroleum refineries; (3) sulfur plant reaction boilers; and (4) RECLAIM facilities (NOx emissions only).	Yes	See more details in the text below.
Regulation XIII: New Source Review for Non-RECLAIM Pollutants	Establishes the pre-construction review requirements for new, modified or relocated facilities to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards and that future economic growth in the SCAQMD is not unnecessarily restricted. However, this regulation does not apply to NOx or SOx emissions from certain sources, which are addressed by Regulation XX (RECLAIM).	Yes	See more details in the text below.
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.	Yes	See more details in the text below.

Applicable LORS	Description	Complies?	Basis of Compliance
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.	Yes	See more details in the text below.
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.	Yes	See more details in the text below.
Regulation XXXI: Acid Rain Permits	Title IV of the federal Clean Air Act provides for the issuance of acid rain permits for qualifying facilities. Regulation XXXI integrates the Title V program with the RECLAIM program. Regulation XXXI requires a subject facility to obtain emission allowances for SOx emissions as well as monitoring SOx, NOx, and carbon dioxide (CO_2) emissions from the facility.	Yes	See more details in the **40 CFR Part 72, Acid Rain Provisions** section below.

The Final Determination of Compliance (FDOC) for Amended HBEP was docketed on November 21, 2016 (SCAQMD 2016g). Compliance with all SCAQMD Rules and Regulations was demonstrated to the SCAQMD's satisfaction in the FDOC, and the draft permit conditions are presented in the conditions of certification located near the end of this section.

FEDERAL

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

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

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

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

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

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

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

VOC emissions would also be controlled with the oxidation catalysts. The oxidation catalysts are effective at operating temperatures above certain temperatures. The facility is required to maintain a temperature gauge in the exhaust of the combined-cycle turbines, which will measure the exhaust temperature on a continuous basis and record the readings on an hourly basis. The exhaust temperature is required to be at least 570°F for the oxidation catalysts of the combined-cycle turbines (with exceptions for start ups and shutdowns [**AQ-36** or SCAQMD condition D12.10]). This will ensure that the oxidation catalyst is operating properly. Compliance is expected.

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

STATE

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

LOCAL

The project owner provided an air quality permit application to the SCAQMD and the SCAQMD has issued an FDOC (SCAQMD 2016g), which states that the Amended HBEP is expected to comply with all applicable SCAQMD rules and regulations.

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

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

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

Regulation II – Permits

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

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

Regulation IV – Prohibitions

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

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

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

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

RULE 407 – Liquid and Gaseous Air Contaminants. This rule limits CO emissions to 2000 ppmv. The CO emissions from the GE 7FA.05 combined-cycle turbines would be controlled by an oxidation catalyst to 1.5 ppmvd at 15 percent O_2. The CO emissions from the GE LMS-100PB simple-cycle turbines would be controlled by an oxidation catalyst to 2.0 ppmvd at 15 percent O_2. The CO emissions from the auxiliary boiler would be maintained at 50 ppmvd at 3 percent O_2. Therefore, compliance with this rule is expected.

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

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

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

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

Regulation XIII – New Source Review (NSR)

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

Best Available Control Technology (BACT)

BACT is required for all criteria pollutants and ammonia. For major sources, BACT is determined at the time the permit is issued, and is the Lowest Achievable Emission Rate (LAER), which has been achieved in practice. SCAQMD has determined that BACT for combined-cycle gas turbines is: NOx 2.0 ppmvd @ 15 percent O_2, one hour average; VOC 2.0 ppmvd @ 15 percent O_2, one hour average; PM10 natural gas fuel; SOx natural gas fuel with fuel sulfur content of no more than one grain/100 scf (about 16 ppm); NH_3 5.0 ppmvd @ 15 percent O_2, one hour average. SCAQMD is still in the process of reviewing the CO BACT limit for the combined-cycle gas turbines. In the interim, AES has proposed to meet the CO limit of 1.5 ppmvd @ 15 percent O_2, one hour average for the combined-cycle gas turbines. SCAQMD has determined that BACT for simple-cycle turbines is: NOx 2.5 ppmvd @ 15 percent O_2, one hour average; CO 2.0 ppmvd @ 15 percent O_2, one hour average; VOC 2.0 ppmvd @ 15 percent O_2, one hour average; PM10 natural gas fuel; SOx natural gas fuel with fuel sulfur content of no more than one grain/100 scf (about 16 ppm); NH_3 5.0 ppmvd @ 15 percent O_2, one hour average. SCAQMD has determined that the BACT for the auxiliary boiler is: NOx 5.0 ppmvd, @ 3 percent O_2, one hour average; CO 100 ppmvd @ 3 percent O_2; PM10 natural gas fuel; SOx natural gas fuel; NH_3 5.0 ppmvd @ 3 percent O_2. Compliance is verified in the DOC.

Modeling

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

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

Offsets

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

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

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

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

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

Other requirements of RULE 1303:

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

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

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

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

***Statewide Compliance*.** The project owner has submitted a statement certifying that all AES's stationary sources are currently in compliance with applicable state and federal environmental regulations. Prior to issuing the Permit to Construct, SCAQMD will confirm that the compliance status of AES has not changed.

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

RULE 1325 – PM2.5 New Source Review. Rule 1325 is the NSR rule for PM2.5 and its precursors, NOx and SO_2. This rule applies to new major polluting facilities, major modifications to existing major polluting facilities, and any modification to an existing facility that would constitute a major polluting facility in and of itself. A major polluting facility is defined as a facility located in a federal non-attainment area for PM2.5 which has actual emissions, or a potential to emit of greater than 100 tons per year, of either PM2.5 or its precursors. Note that on December 22, 2015, the U.S. EPA re-classified the South Coast basin as serious non-attainment for PM2.5. This effectively reduces the major source threshold from 100 tons per year to 70 tons per year.

On November 4, 2016, SCAQMD adopted amended Rule 1325 to align it with the recent reclassification and with U.S. EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule. Amendments to Rule 1325 establish appropriate major stationary source thresholds for direct PM2.5 and PM2.5 precursors, including VOC and ammonia. The amendments are intended to facilitate State Implementation Plan (SIP) approval of the regulations.

The amendments add ammonia and VOC as precursors to PM2.5, per Clean Air Act Subpart 4 requirements. These amendments will be effective after August 14, 2017 or upon the effective date of U.S. EPA's approval of these amendments to this rule, whichever is later. U.S. EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule states an area can rely on the SIP-approved version of Rule 1325 until the new rule is fully incorporated into the SIP. 81 Fed Reg 58010 (August 24, 2016).

A major modification is defined as any physical change or change in the method of operation at a major polluting facility which results in: a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major polluting facility. If subject to this subpart, the facility is required to comply with the following requirements: 1) use lowest achievable emissions rate (LAER), 2) offset PM2.5 emissions at the applicable offset ratio, 3) certification of compliance with emission limits for all major sources under common control, and 4) conduct an alternatives analysis of the project. The existing facility is not a major source for PM2.5 and SO_2, but is a major source for NOx, which is a PM2.5 precursor. The Amended HBEP is considered a major modification to an existing major source for NO_2 and is subject to NSR under this rule for NOx only. The Amended HBEP is also considered a major modification for NOx under SCAQMD Rule 2005 and Regulation XVII (PSD), and as such, all of the requirements listed above are addressed under those rules. The total PM2.5 potential to emit of 69.6 tons/year from the Amended HBEP would not result in an emissions increase above the 100 tons/year threshold of the SIP-approved version of Rule 1325 (or 70 tons/year after the August 14, 2017 or upon the effective date of U.S. EPA's approval of the amendments to Rule 1325, whichever is later). Therefore, the Amended HBEP will continue to be a non-major polluting facility for PM2.5 and would not be subject to Rule 1325 requirements.

Staff expects that the Amended HBEP would be approved and construction would commence before the amended version of Rule 1325 becomes effective. Therefore, staff does not expect the amended Rule 1325 to be applicable to the Amended HBEP. However, if the permit is still under review or if construction has not commenced and a permit extension is requested after the amended rule becomes effective, the new threshold limit will need to be evaluated as it pertains to the Amended HBEP.

Regulation XVII – Prevention of Significant Deterioration (PSD)

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

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

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

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

Visibility Analysis

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

Soil and Vegetation Analysis

The project owner found that the project impacts do not exceed the secondary NAAQS and concluded that there will be no significant impacts to soil and vegetation. The modeling was reviewed by SCAQMD modeling staff and deemed acceptable. The application documents and modeling files were forwarded to the Federal Land Managers (US Forest Service and National Park Service) on January 6, 2016 to provide these agencies the opportunity to review and comment on the potential impacts of the proposed project on Class I areas. Both agencies have responded and indicated there are no adverse impacts or made no comments on the proposed project.

Expiration of Permits under SCAQMD and PSD Rules for Phased Projects

This would be a phased construction project. Phase 1 of the project would consist of the construction of the two combined-cycle turbines, their stacks and associated control equipment, the auxiliary boiler, the aqueous ammonia tank (SCAQMD ID number D150), and the oil water separator (SCAQMD ID number D152). The start of construction for Phase 1 would be in the 2nd quarter of 2017. Phase 2 of the project would consist of the construction of the two simple-cycle turbines, their stacks and associated control equipment, the aqueous ammonia tank (SCAQMD ID number D151), and the oil water separator (SCAQMD ID number D153). The start of construction for Phase 2 of the project would be in the 2nd quarter of 2022.

Under Rule 205, the permit issued by SCAQMD is valid for one year from the date it is issued and construction must be completed within one year. Extensions of the one-year deadline can be granted upon request from the facility, in consideration of the reason needed for the extension. In the case of the Amended HBEP, both Phase 1 and Phase 2 would be multi-year construction projects, and permit extensions in these situations are commonly granted by SCAQMD, with a requirement to provide project milestone dates and regular status updates as a condition of the extension.

PSD regulations under 40 CFR 52.21(r)(2) allow up to 18 months from the date the permit is issued for construction to commence. Construction cannot be discontinued for more than 18 months, and construction must be completed “within a reasonable time.” An extension of the 18-month time frame is allowed upon a “satisfactory showing that an extension is justified.”

In accordance with 40 CFR 52.21, for phased construction projects, the BACT determination made at the time the permit is issued may need to be reviewed and updated, if appropriate, no more than 18 months before the start of construction of each phase. A re-review of BACT for Phase 1 of the project is not expected as the proposed construction schedule is within 18 months of the anticipated permit date. However, in the case of Phase 2, a re-analysis of BACT and other PSD requirements for the simple-cycle turbines may need to be made prior to the start of construction for those units. According to U.S. EPA guidance for a permit re-opening such as this, it is advisable that it include a public participation process as well, if the re-analysis results in a substantial modification of the permit terms or conditions. Additionally, the U.S. EPA recommends that once a permit extension request under 40 CFR 52.21 has been granted (i.e. when construction does not begin within 18 months of the date of the permit), the permitting authority should notify the public of the permit extension decision, especially when the public expressed significant interest in the initial permitting decision *(Guidance on Extension of Prevention of Significant Deterioration Permits under 40 CFR 52.21(r)(2), U.S. EPA, Jan 31, 2014)*.

Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

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

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

Regulation XXX – Title V

The existing Huntington Beach facility is currently subject to Title V requirements, and is operating under a valid Title V permit issued on April 29, 2016. The addition of the combined-cycle/simple-cycle plant and auxiliary equipment would be considered a significant revision to the existing Title V permit. AES has submitted a Title V revision application A/N 578087. As a significant revision, the permit is subject to a 30-day public notice and a 45-day U.S. EPA review and comment period.

The initial public notice of the release of the PDOC wherein the SCAQMD stated their intent to issue Permits to Construct and to revise the Title V permit for the facility was published in a local newspaper on June 9, 2016, placed on SCAQMD's website, and also sent to the U.S. EPA, Energy Commission (SCAQMD 2016a), other agency contacts, and interested parties. The notice was also mailed to addresses within ¼ mile of the facility on June 16, 2016.

After receiving comments on the notice procedure, and in consideration of the fact that the Energy Commission's Preliminary Staff Assessment (PSA) was released on June 24, 2016 and therefore only available for a portion of the time of SCAQMD's 30-day notice period, SCAQMD decided to re-notice the PDOC for the project. On November 17, 2016 the re-notice was published in a local newspaper and sent to agency contacts and interested parties (SCAQMD 2016e). On November 15, 2016, the re-notice was mailed to addresses within ¼ mile of the facility. The documents available for the re-notice period were the same documents that were available during the original notice period. The re-notice comment period for the public ends December 20, 2016.

Title V permits are also subject to the review and approval by U.S. EPA. If a public comment is sent to the SCAQMD for this permit, the SCAQMD has not addressed the comment in a satisfactory manner, and the U.S. EPA has not objected to the proposed permit, then the public may submit a petition requesting that the U.S. EPA reconsider the decision not to object. Petitions shall be submitted to U.S. EPA, Region 9, within 60 days after the end of the 45-day U.S. EPA review period. The U.S. EPA review period starts no earlier than November 10, 2016 (SCAQMD 2016e).

ENVIRONMENTAL IMPACT ANALYSIS

SETTING

Meteorological Conditions

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

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

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

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

Ambient Air Quality Standards

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

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

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

Air Quality Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.070 ppm (137 μg/m^3)[a]	0.070 ppm (137 μg/m^3)
	1 Hour	—	0.09 ppm (180 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual	53 ppb (100 μg/m^3)	0.030 ppm (57 μg/m^3)
	1 Hour	100 ppb (188 μg/m^3)[b]	0.18 ppm (339 μg/m^3)
Sulfur Dioxide (SO_2)	24 Hour	—	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1300 μg/m^3)	—
	1 Hour	75 ppb (196 μg/m^3)[c]	0.25 ppm (655 μg/m^3)
Respirable Particulate Matter (PM10)	Annual	—	20 μg/m^3
	24 Hour	150 μg/m^3	50 μg/m^3
Fine Particulate Matter (PM2.5)	Annual	12.0 μg/m^3	12 μg/m^3
	24 Hour	35 μg/m^3 [b]	—
Sulfates (SO_4)	24 Hour	—	25 μg/m^3
Lead	30 Day Average	—	1.5 μg/m^3
	Rolling 3-Month Average	0.15 μg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.01 ppm (26 μg/m^3)
Visibility Reducing Particulates	8 Hour	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.

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

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

Existing Ambient Air Quality

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

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

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

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

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

Nonattainment Criteria Pollutants

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

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

Air Quality Table 4
Nonattainment Criteria Pollutants Concentrations, 2009-2014 (ppm or μg/m^3)

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

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

Ozone

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

Respirable Particulate Matter (PM10)

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

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

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

Fine Particulate Matter (PM2.5)

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

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

Attainment Criteria Pollutants

Nitrogen Dioxide (NO_2)

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

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

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

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

Carbon Monoxide

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

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

Pollutant	Averaging Time	2009	2010	2011	2012	2013	2014
NO_2	1 hour	0.07	0.07	0.06	0.074	0.0757	0.0606
NO_2	Federal 1 hour	0.057	0.056	0.053	0.05	0.0532	0.0547
NO_2	Annual	0.013	0.011	0.01	0.01	0.0116	0.011
CO	1 hour	3	2	2.9	2.1	2.4	3
CO	8 hours	2.2	2.1	2.2	1.7	2	1.9
SO_2	State 1 hour	0.01	0.01	0.008	0.006	0.0042	0.0088
SO_2	Federal 1 hour (99^{th} percentile)	0.006	0.006	0.005	0.002	0.0033	0.004
SO_2	24 hour	0.004	0.002	0.002	0.001	0.0012	0.0014

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

Sulfur Dioxide

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

Summary of Existing Ambient Air Quality

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

Air Quality Table 6
Staff-Recommended Background Concentrations (µg/m^3)

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

Source: ARB 2016c, SCAQMD 2016, U.S. EPA 2016c and independent staff analysis.
Note:
[a] An exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.
[b] The federal 24-hour PM2.5, federal 1-hour SO_2, and federal 1-hour NO_2 standards are based on 98th/99th percentiles averaged over 3 years. However, to be conservative, staff used the maximum of the 98th/99th percentile values over the last three years of available data as the recommended background data, instead of the 3-year averages.

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

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

PROJECT DESCRIPTION AND PROPOSED EMISSIONS

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

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

PROPOSED CONSTRUCTION EMISSIONS

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

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

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

During the construction period, air emissions would be generated from: 1) vehicle and construction equipment exhaust; 2) fugitive dust from vehicle and construction equipment, including grading and bulldozing during construction of the Amended HBEP; and 3) fugitive dust from demolition activities such as the removal of the stacks and loading waste haul trucks with the generated debris. Construction emissions are estimated based on the work schedule of 10 hours per day, 23 days per month (HBEP 2015a).

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

Air Quality Table 7
Estimated Maximum Construction Emissions

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

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

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

PROPOSED INITIAL COMMISSIONING EMISSIONS

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

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

Air Quality Table 8
Maximum Initial Commissioning Emissions

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

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

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

PROPOSED OPERATION EMISSIONS

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

- NOx emissions would be controlled to 2.0 parts per million by volume, dry basis (ppmvd), corrected to 15 percent oxygen for each GE 7FA.05 turbine, 2.5 ppmvd for each GE LMS-100PB turbine, and 5.0 ppmvd corrected to 3 percent oxygen for the auxiliary boiler;
- VOC emissions would be controlled to 2.0 ppmvd for the turbines with the use of good combustion practices and an oxidation catalyst;
- CO emissions would be controlled to 1.5 ppmvd corrected to 15 percent oxygen for each GE 7FA.05 turbine, 2.0 ppmvd corrected to 15 percent oxygen for each GE LMS-100PB turbine, and 50 ppmvd corrected to 3 percent oxygen for the auxiliary boiler;
- PM10/PM2.5 emissions would be limited to 8.5 lbs/hr for each GE 7FA.05 turbine and 6.24 lbs/hr for each GE LMS-100PB turbine;
- SOx emissions would be based on sulfur content of 0.75 gr/100 cf for short term (hourly, daily, monthly) emissions and 0.25 gr/100 cf for long term (annual) emissions;
- Maximum annual operating emissions from each GE 7FA.05 turbine would be based on 6,100 hours of full load operation, plus 80 cold startups, 420 non-cold startups, and 500 shutdowns; and
- Maximum annual operating emissions from each GE LMS-100PB turbine would be based on 1,750 hours of full load operation, plus 350 startups, and 350 shutdowns.

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

For the GE LMS-100PB turbines, there could be an hour when both a startup and shutdown occur. For such hours, there would be 30 minutes of elevated emissions due to the startup, 17 minutes of normal operation, and 13 minutes of elevated emissions due to shutdown. Since PM10/PM2.5 and SOx emissions are proportional to fuel use, PM10/PM2.5 and SOx have higher emissions rates during full-load operation. The worst case hourly emissions of each GE LMS-100PB turbine would be lower than those approved for each Mitsubishi Heavy Industries 501DA turbine of the licensed HBEP.

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

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

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

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

Air Quality Table 10 lists maximum daily emissions of the Amended HBEP. The daily emissions are calculated as monthly emissions divided by 30. The monthly emissions of each GE 7FA.05 turbine are based on the assumption of 31 days of operation including 15 cold startups, 47 non-cold startups, and 62 shutdowns per month (startups and shutdowns are defined and limited in **AQ-24** and **AQ-25**). The monthly emissions of each GE LMS-100PB turbine are based on the assumption of 31 days of operation including 62 startups and 62 shutdowns per month (startups and shutdowns are defined and limited in **AQ-27** and **AQ-28**). The monthly emissions of the auxiliary boiler are based on the assumption of 2 cold startups, 4 warm startups, 4 hot startups (startups are defined and limited in **AQ-30**), and 15,793 MMBtu of fuel consumption for normal operations per month.

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

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

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Amended HBEP					
Total of two GE 7FA.05 turbines	911	507	422	1,648	228
Total of two GE LMS-100PB turbines	464	131	310	366[a]	89.2
Auxiliary boiler	3.8	2.9	4.0	21.7	1.1
Oil Water Separators	--	0.54	--	--	--
Facility Total	1,378.8	642.3	735.1	2,036.0	318.5
Licensed HEBP					
Maximum Facility Total (Six Turbines) of Three Scenarios	2,035	1,744	798	3,208	321

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

Air Quality Table 11 lists maximum potential annual emissions from the Amended HBEP project, based on project owner and SCAQMD calculations reviewed by staff. The operating profile of each GE 7FA.05 turbine includes 6,100 hours of full load operation, 80 cold startups, 420 non-cold startups, and 500 shutdowns per year (startups and shutdowns are defined and limited in **AQ-24** and **AQ-25**). The operating profile of each GE LMS-100PB turbine includes 1,750 hours of full load operation, 350 startups, and 350 shutdowns per year (startups and shutdowns are defined and limited in **AQ-27** and **AQ-28**). The maximum annual emissions of the auxiliary boiler are based on 24 cold startups, 48 warm startups, 48 hot startups (startups are defined and limited in **AQ-30**), and 182,703 MMBtu of fuel consumption for normal operations per year. **Air Quality Table 11** shows that the facility total annual emissions of the Amended HBEP would be lower than those approved for the licensed HBEP.

Ammonia Emissions

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

As with the licensed HBEP, SCAQMD requires a maximum ammonia slip rate of 5 ppmvd at 15 percent oxygen for the proposed turbines and 5 ppmvd at 3 percent oxygen for the auxiliary boiler (SCAQMD 2016g). The project owner expects the ammonia slip rate from the SCRs of the GE 7FA.05 turbines, the GE LMS-100PB turbines, and the auxiliary boiler would not exceed the 5 ppmvd limit. Energy Commission staff notes that control systems can be operated and maintained to routinely achieve less than 5 ppmvd, as established in the Guidance for Power Plant Siting (ARB 1999). Staff recommends that the Energy Commission impose a 5 ppmvd emissions limit in Conditions of Certification **AQ-16** and **AQ-21**.

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

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Amended HBEP					
Total of two GE 7FA.05 turbines	120	64.8	56.4	196.7	10.0
Total of two GE LMS-100PB turbines	21.3	6.1	12.5	22.2[a]	1.2
Auxiliary boiler	0.7	0.5	0.7	3.8	0.2
Oil Water Separators	--	0.10	--	--	--
Facility Total	141.4	71.4	69.6	222.7	11.4
Licensed HBEP					
Facility Total (Six Turbines)	251.0	167.7	99.3	282.8	15.3

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

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

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

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

DIRECT/INDIRECT IMPACTS AND MITIGATION

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

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

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

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

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

Construction Impacts and Mitigation

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

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

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

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

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

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

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

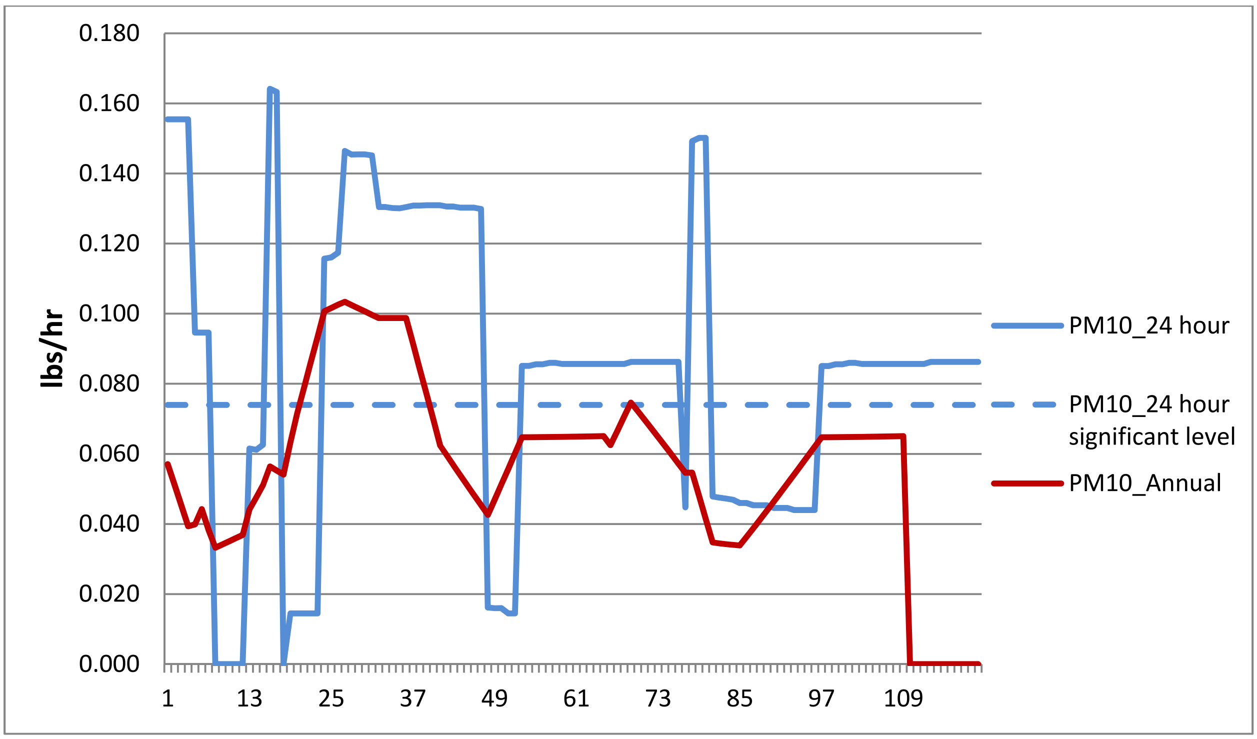
To determine worst-case impacts for both 24-hour and annual averages, the modeling assumes that the maximum emission rates occur during the entire 120-month construction period. However, maximum emissions are only expected to occur over a relatively short portion of the 120-month construction period.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

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

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

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

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

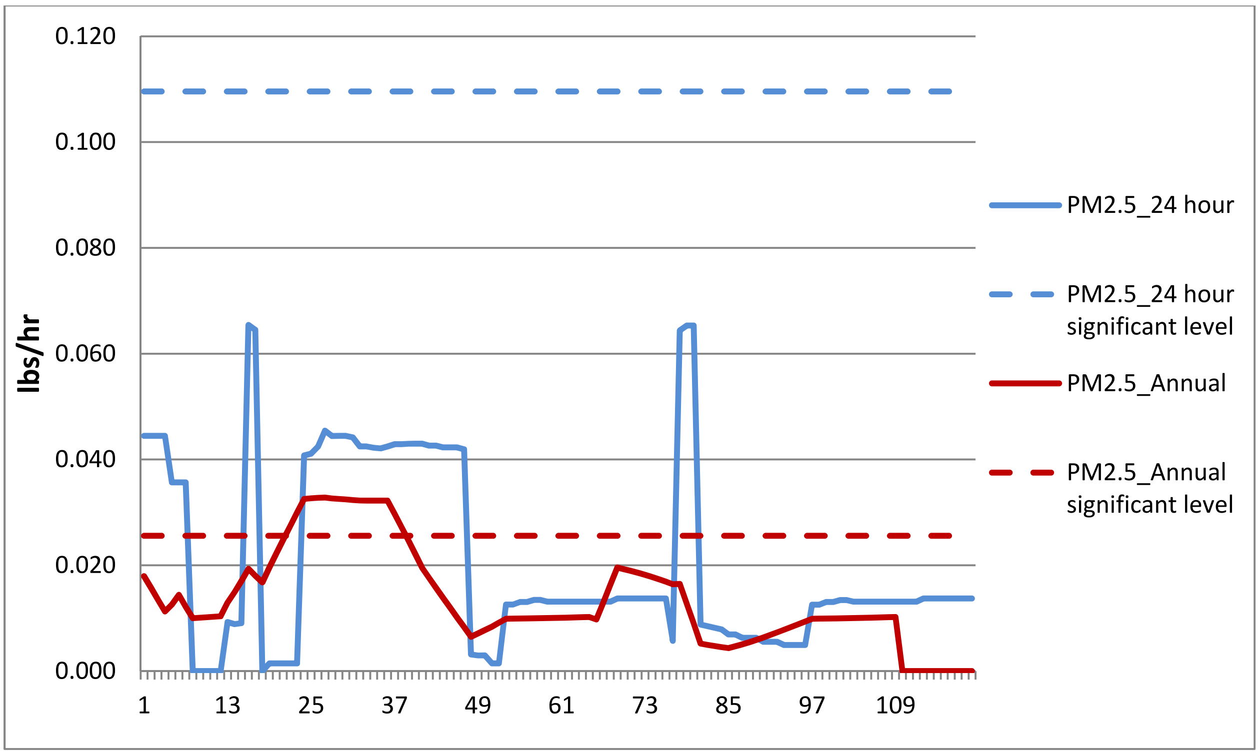


Source: HBEP 2015c, HBEP 2015h, with independent staff analysis.
Note: Worst case emission rates for the 24-hour case are calculated from the worst daily emissions of the month divided by 24 hours/day. Worst case emission rates for the annual case are calculated from the rolling maximum yearly emissions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

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

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

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



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

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

Construction Mitigation

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

- Watering unpaved roads and disturbed areas
- Limiting onsite vehicle speeds to 10 mph and post the speed limit
- Frequent watering during periods of high winds when excavation/grading is occurring
- Sweeping onsite paved roads and entrance roads on an as-needed basis
- Replacing ground cover in disturbed areas as soon as practical
- Covering truck loads when hauling material that could be entrained during transit
- Applying dust suppressants or covers to soil stockpiles and disturbed areas when inactive for more than 2 weeks
- Using ultra-low sulfur diesel fuel (15 ppm sulfur) in all diesel-fueled equipment
- Use of Tier 4 construction equipment where feasible
- Maintaining all diesel-fueled equipment per manufacturer’s recommendations to reduce tailpipe emissions
- Limiting diesel heavy equipment idling to less than 5 minutes, to the extent practical
- Using electric motors for construction equipment to the extent feasible.

Since the modeling results in **Air Quality Table 12** show that PM10 and PM2.5 impacts during the 10-year project construction period would cause exceedances of health-based ambient air quality standards and because staff determined that these impacts would be significant, staff recommends that additional mitigation measures need to be employed to further reduced construction period emissions and potential impacts.

For the licensed HBEP, the project owner proposed to sweep roadways in the project vicinity during the construction period with SCAQMD-certified street sweepers. The project owner proposed to use the Pacific Coast Highway (PCH) for street sweeping, and they also listed additional roads that could be used and the associated traffic volumes. The project owner estimated the number of miles where sweeping would be required to mitigate the construction impacts, assuming that only the PCH would be swept. This mileage was calculated from the amount of emissions reduction required to get PM impacts below the corresponding ambient air quality standard, the control efficiency achieved by sweeping once per month, fugitive dust emission factors for paved roads, and daily vehicle traffic volume on the PCH.

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

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

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

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

Adequacy of Proposed Mitigation

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

Staff also agrees that the street sweeping program is an effective way to further mitigate the PM impacts during the extended construction period. To implement this measure, staff proposes that the Energy Commission requires the project owner to develop and provide a street sweeping mitigation plan prior to initiating construction that details the sweeping program and provide the records of the operation of the sweeping program in Monthly Compliance Reports. On June 28, 2016, the project owner submitted a Construction Particulate Matter Mitigation Plan to the Energy Commission. This plan is applicable to the Limited Notice to Proceed activities associated with the licensed HBEP. The project owner proposes to conduct street sweeping of nearby public roadways (Newland St., Hamilton Ave., Brookhurst St., and Adams Ave.), instead of PCH, beyond 500 feet of any paved public roadway exiting the construction site on a monthly basis. The project owner proposed to sweep a total of 5.15 miles once per month. The resultant emission reductions from the project owner's proposed plan would be 8.9 lbs/day for PM10 and 2.23 lbs/day for PM2.5, which would exceed the required amount of 8.26 lbs/day for PM10 and 0.79 lbs/day for PM2.5 for the licensed HBEP, and well above the amounts needed for the Amended HBEP - 2.17 lbs/day for PM10 and 0.17 lbs/day for PM2.5. Therefore, the project owner may wish to update the Construction Particulate Matter Mitigation Plan if significant earth-moving construction activities remain, assuming the amendment request is granted.

Staff Proposed Mitigation

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

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

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

As discussed above regarding the Limited Notice to Proceed for the licensed HBEP, the Energy Commission's compliance project manager has approved the project owner's Construction Particulate Matter Mitigation Plan dated June 28, 2016, as required by **AQ-SC6**. The resultant emission reductions from the project owner's proposed plan exceed the required amount of 8.26 lbs/day for PM10 and 0.79 lbs/day for PM2.5 for the licensed HBEP. For the Amended HBEP, staff proposes to reduce the required construction emissions reduction to 2.17 lbs/day for PM10 and 0.17 lbs/day for PM2.5. Therefore, compliance with the revised **AQ-SC6** is expected. Staff believes that the significant PM impacts during the construction would be reduced to less than significant by the street sweeping program.

Operation Impacts and Mitigation

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

Routine Operation Impacts

A refined dispersion modeling analysis was performed by the project owner to identify off-site criteria pollutant impacts that would occur from routine operational emissions throughout the life of the project. The worst case 1-hour NO_2 and CO impacts reflect startup impacts, and all other impacts reflect impacts that would occur during normal operation. The modeled impacts are extremely conservative, since the maximum impacts are evaluated under a combination of highest allowable emission rates, the most extreme meteorological conditions, and worst case background values, which are unlikely to all occur simultaneously. Emissions rates are shown in **Air Quality Tables 9** to **11**. The predicted maximum concentrations of criteria pollutants are summarized in **Air Quality Table 13**. The values shown in **bold** means they exceed ambient air quality standards.

Air Quality Table 13 shows that with the worst-case modeled 24-hour PM10 impact of 5.1 μg/m^3 and maximum background at 45 μg/m^3, the total 24-hour PM10 impact would be 50.1 μg/m^3, which is a little above the 24-hour PM10 CAAQ of 50 μg/m^3. However, the worst-case modeling conservatively assumed that each of the GE 7FA.05 turbines would operate at 44 percent load for 24 hours per day (with operation of the GE LMS-100PB turbines and the auxiliary boiler), which is an unlikely scenario. For the PSD impacts analysis, the project owner performed a refined modeling analysis assuming one GE 7FA.05 would operate 24 hours per day at 44 percent load and the other would operate 20 hours per day at 44 percent load and 4 hours per day at 75 percent load. The maximum modeled 24-hour PM10 impact in this scenario would be 4.97 μg/m^3 from the project owner's refined analysis. Combining the maximum background at 45 μg/m^3, the total 24-hour PM10 impact would be 49.97 μg/m^3, which would be less than the 24-hour PM10 CAAQ of 50 μg/m^3.

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

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

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	5.1 (4.97) [e]	45	**50.1** (49.97) [e]	**50**	**100.2** (99.9) [e]
	Annual	0.64	**24.2**	**24.8**	**20**	**124**
PM2.5	24 hour [a]	5.1	27.8	32.9	35	94
	Annual	0.64	11.34	11.98	12	99.8
CO [f]	1 hour	630.6	3,450	4,080.6	23,000	18
	8 hour	149	2,222	2,371	10,000	24
NO_2 [b]	State 1 hour	94.5	142.6	237.1	339	70
	Federal 1 hour [c]	--	--	126.0	188	67
	Annual	0.59	22	22.6	57	40
SO_2	State 1 hour	5.8	23.1	28.9	655	4
	Federal 1 hour [d]	5.8	10.5	16.3	196	8
	24 hour	1.7	3.7	5.4	105	5

Source: HBEP 2015h, HBEP 2016n, and independent staff analysis
Notes:
[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year maximum of 98th percentile background concentrations.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.
[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year maximum of 99th percentile background concentrations.
[e] Worst-case modeling assumed each GE 7FA.05 turbine operating at 44 percent load for 24 hours per day, which is an unlikely scenario. A more refined analysis (results shown in parentheses) assumed that one GE 7FA.05 turbine would operate at 44 percent load for 24 hours per day and the other would operate 20 hours per day at 44 percent load and 4 hours per day at 75 percent load. Staff performed additional analysis and concludes that the Amended HBEP is not likely to cause exceedance of the 24-hour PM10 standard. See more details in the text.
[f] The CO impacts of simple-cycle turbines during normal operations were modeled at emission rates of 4.0 ppm. However, the FDOC determined that the CO BACT level should be reduced to 2.0 ppm for the simple-cycle turbines. The modeled emission rates used for the facility's impact analysis were higher and more conservative than the revised CO limit. Therefore, re-modeling of CO impacts is not required. Similarly, the impacts of combined-cycle turbines during normal operations were modeled at emission rates of 2.0 ppm. However, during review of the PDOC, the project owner proposed a CO limit of 1.5 ppm for these units and re-modeling of CO impacts is not required for the same reason.

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

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

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

Secondary Pollutant Impacts

The gaseous emissions of NOx, SOx, VOC, and ammonia from the Amended HBEP are precursor pollutants that can contribute to the formation of secondary pollutants (ozone, PM10, and PM2.5). Gas-to-particulate conversion in ambient air involves complex chemical and physical processes that depend on many factors, including local humidity, pollutant travel time, and the presence of other compounds. Currently, there are no agency-recommended models or procedures for estimating secondary pollutant ozone or particulate nitrate or sulfate formation from a single project or source. However, because of the known relationships of NOx and VOC to form ozone and of NOx, SOx, and ammonia emissions to form secondary PM10 and PM2.5, it can be said that unmitigated emissions of these pollutants would contribute to higher ozone and PM10/PM2.5 levels in the region. Mitigating SOx and NOx emissions would both avoid significant secondary PM10/PM2.5 impacts and reduce secondary pollutant impacts to a less than significant level.

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

Energy Commission staff recommends limiting ammonia slip emissions to the maximum extent feasible. This level of control is appropriate for avoiding unnecessary ammonia emissions, consistent with staff policy to reduce emissions of all nonattainment pollutant precursors to the lowest feasible levels. Consistent with the SCAQMD's requirement on the ammonia slip rate (SCAQMD 2016g), staff recommends an ammonia slip limit of 5 ppmvd in Conditions of Certification **AQ-16** and **AQ-21**.

Fumigation Impacts

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

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

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

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

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

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

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

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

Commissioning Phase Impacts

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

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

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

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

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

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

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

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

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

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

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

Mitigation for Routine Operation

Project Owner's Proposed Mitigation

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

Emission Controls

The project owner proposes the use of dry low NOx combustors with selective catalytic reduction (SCR) to control NOx emissions to 2.0 ppmvd (1-hour average) for the GE 7FA.05 combined-cycle turbines and 2.5 ppmvd (1-hour average) for the GE LMS-100PB simple-cycle turbines. The project owner proposes the use of low NOx burners with flue gas recirculation and SCR to control NOx emissions of the auxiliary boiler to 5.0 ppmvd corrected to 3 percent oxygen. The project owner proposes the use of best combustion design and the installation of an oxidation catalyst system to reduce CO to 1.5 ppmvd for the GE 7FA.05 combined-cycle turbines and 2.0 ppmvd (1-hour average) for the GE LMS-100PB simple-cycle turbines. The project owner proposes to use flue gas recirculation and good combustion design to control CO emissions of the auxiliary boiler to 50 ppmvd.

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

Emission Offsets

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

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

The SCAQMD's FDOC shows the total power generating capacity from the proposed turbines would be 895.5 MW gross. The Amended HBEP output would be limited by Conditions of Certification **AQ-59** (SCAQMD condition E448.1) and **AQ-60** (SCAQMD condition E448.2). In order to qualify for the exemption, the project owner is proposing to shut down HBGS Units 1 and 2 and RBGS Unit 7. The capacity of each of the HBGS Units 1 and 2 is 215 MW gross. The capacity of RBGS Unit 7 is 480 MW gross. The total capacity of the units being shutdown would be 910 MW gross. Therefore the net megawatts would decrease and the new power generating system would qualify for the Rule 1304(a)(2) exemption. Thus, the facility does not have to provide emission reduction credits for VOC and PM10 emissions of the new turbines. Instead, the VOC and PM10 emissions of the new turbines would be fully offset from SCAQMD's internal bank. However, SCAQMD decided that the auxiliary boiler and oil/water separators are not eligible for exemption under Rule 1304(a)(2) and the project owner is required to provide offsets for these emissions. Offsets for non-RECLAIM pollutants VOC and PM10 (offsets for CO emissions are not required) for these equipment would be provided in the form of ERCs.

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

Under Rule 2005, RTCs to cover the expected emissions of NOx for the Amended HBEP are required to be held for the first compliance year. Additionally, since the NOx PTE after the first year would be less than the facility's initial allocation (1,276,547 lbs/yr [SCAQMD 2016g]), the facility is not required to hold NOx RTCs for subsequent years. But the SCAQMD will make sure the facility has enough NOx RTCs for its actual emissions. The Huntington Beach facility is also in the SOx RECLAIM program.

Therefore, SOx RTCs are required to be held to cover the first year of operation. Additionally, because the facility opted into SOx RECLAIM after 1994, there is no initial allocation. For this reason, SOx RTCs are required to be held for each compliance year after the first year of operation [paragraph (f)(1)].

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

The VOC and PM10 emissions shown in **Air Quality Table 17** are calculated from the maximum monthly emissions limits in the FDOC 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 VOC and PM10 emissions on a 30-day average are calculated by totaling the worst case month that the project is expected to have and dividing that total by 30 to create an estimate of the 30-day averaged daily emissions. A project must obtain ERCs for the 30-day average lbs/day value. A lbs/day average based on an annual average is always going to be lower than a lbs/day average based on a worst case month for the same emitting source. Any emitting source will always have a month where it emits more pollutants than any other month, but in an annual average this peak month is washed out over the year. Thus the lbs/day ERC calculation is more conservative than the lbs/day annual average emission calculation. Therefore, for projects located in the SCAQMD, staff uses the 30-day average lbs/day value to characterize the project emissions profile when comparing it to the ERCs being offered.

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

Air Quality Table 17
CEQA Mitigation

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

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

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

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

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

Adequacy of Proposed Mitigation

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

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

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

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

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

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

Staff Proposed Mitigation

Staff proposes to keep the approved Conditions of Certification **AQ-SC7** to ensure that the license is amended as necessary to incorporate any future changes to the air quality permits and to ensure ongoing compliance during commissioning and routine operation through quarterly reports (**AQ-SC8**). Staff also proposes a new Condition of Certification (**AQ-SC9**) to ensure that the emissions of the auxiliary boiler and the oil/water separators would be mitigated with the quantity of SCAQMD offsets recommended by the SCAQMD and Energy Commission staff and to ensure agency consultation if substitutions are made to the credits. Staff proposes a new Condition of Certification (**AQ-SC10**) to establish appropriate guidelines on what would be considered a significant change to a condition of certification. This condition is compatible with many air district rules and regulations which already have established mechanisms approved by ARB and the U.S. EPA to make minor changes that do not involve significant change to existing monitoring, reporting or recordkeeping requirement or require a case-by-case determination of any emission limitation. This would allow the CPM to approve administrative changes (such as typographical errors, facility name or owner) and other minor changes. The condition requires the project owner to apply for approval of the change and grants authority for the CPM to approve the change before the change would become effective.

Overlap Periods Impacts and Mitigation

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

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

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

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

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

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

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

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

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

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

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

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

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

Air Quality Table 19 also shows that the worst-case total annual PM2.5 impacts during this overlap period would be equal to the limiting annual PM2.5 standard of 12 μg/m^3 due to the existing high background concentrations. The worst-case annual PM2.5 project impacts during this overlap period would be mainly from the operation of the Amended HBEP, with a portion of the impacts from demolition of HBGS Units 1 and 2. The project owner's modeling conservatively assumed that both the GE 7FA.05 combined-cycle turbines would continuously operate at 44 percent load, which is unlikely to occur. Annual impacts from other operating scenarios would be less than those modeled for the 44 percent load scenario. The project owner agreed to accept a permit condition (SCAQMD condition C1.9 [**AQ-26**]) to limit the simultaneous operation of the combined-cycle turbines at 44 percent load to less than 20 consecutive hours. Therefore, the total annual PM2.5 impacts would be less than the limiting standard of 12 μg/m^3. In addition, mitigation measures proposed for the operation of the Amended HBEP and construction/demolition activities would reduce potential impacts of the Amended HBEP to less than significant.

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

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

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

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

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

Air Quality Table 20
Amended HBEP, Maximum Impacts from Combined-cylce Power Block Operation, HBGS Units 3 and 4 Demolition, and HBGS Unit 2 Operation (µg/m³)

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

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

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

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

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

Air Quality Table 21
Amended HBEP, Maximum Impacts from HBGS Units 1 and 2 Operation and Combined-cylce Power Block Construction/demolition Activities (µg/m^3)

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

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

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

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

Cumulative Impacts and Mitigation

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

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

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

- a summary of projections for criteria pollutants by the air District and the air District's programmatic efforts to abate such pollution;
- an analysis of the project's "localized cumulative impacts" when combined with other local major emission sources; and
- a discussion of greenhouse gas emissions and global climate change impacts (in **Air Quality Appendix AIR-1**).

Summary of Projections

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

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

2012 Air Quality Management Plan

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

> *The SCAQMD adopted (December 7, 2012) the 2012 Air Quality Management Plan (AQMP) primarily in response to changes in the federal Clean Air Act (CAA). The CAA requires a 24-hour PM2.5 nonattainment area to prepare a State Implementation Plan (SIP) which must be submitted to U.S. EPA by December 14, 2012. The SIP must demonstrate attainment with the 24-hour PM2.5 standard by 2014, with the possibility of up to a five-year extension to 2019, if needed. U.S. EPA approval of any extension request is based on the lack of feasible control measures to move forward the attainment date by one year. The District's attainment demonstration shows that, with implementation of all feasible controls, the earliest possible attainment date is 2014, and thus no extension of the attainment date is needed. In addition, the U.S. EPA requires that transportation conformity budgets be established based on the most recent planning assumptions (i.e., within the last five years) and approved motor vehicle emission models. The Final Plan is based on the most recent assumptions provided by both ARB and Southern California Association of Governments (SCAG) for motor vehicle emissions and demographic updates and includes updated transportation conformity budgets.*
>
> *The Final 2012 AQMP outlines a comprehensive control strategy that meets the requirement for expeditious progress towards attainment with the 24-hour PM2.5 NAAQS in 2014 with all feasible control measures. The Plan also includes specific measures to further implement the ozone strategy in the 2007 AQMP to assist attaining the 8-hour ozone standard by 2023. The control measures contained in the Final 2012 AQMP can be categorized as follows:*

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

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

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

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

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

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

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

2007 Air Quality Management Plan

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

> *The SCAQMD adopted (June 1, 2007) the 2007 Air Quality Management Plan (AQMP) primarily in response to changes in the federal Clean Air Act (CAA). The CAA requires an 8-hour ozone non-attainment area to prepare a SIP revision by June 2007 and a PM2.5 non-attainment area to submit by April 2008. The SCAQMD has decided that it is most prudent to prepare a single comprehensive and integrated SIP revision that satisfies both the ozone and PM2.5 requirements. Additionally, the U.S. EPA requires that transportation conformity budgets be established based on the most recent planning assumptions and approved motor vehicle emission model. The AQMP is based on assumptions provided by both the California Air Resources Board (ARB) and the Southern California Association of Governments (SCAG) reflecting their upcoming model (EMFAC) for motor vehicle emissions and demographic updates.*
>
> *The Final 2007 AQMP relies on a comprehensive and integrated control approach to achieve the PM2.5 standard by 2015 through implementation of short-term and mid-term control measures and achieve the 8-hour ozone standard by 2024 based on implementation of additional long-term measures. In order to demonstrate attainment by the prescribed deadlines, emission reductions needed for attainment must be in place by 2014 and 2023 timeframe.*
>
> *The AQMP control measures consist of four components: 1) the District's Stationary and Mobile Source Control Measures; 2) ARB's Proposed State Strategy; 3) District Staff's Proposed Policy Options to Supplement ARB's Control Strategy; and 4) Regional Transportation Strategy and Control Measures provided by SCAG.*
>
> *In order to achieve necessary reductions for meeting air quality standards, all four agencies (i.e., SCAQMD, ARB, U.S. EPA, and SCAG) would have to aggressively develop and implement control strategies through their respective plans, regulations, and alternative approaches for pollution sources within their primary jurisdiction. Even though SCAG does not have direct authority over mobile source emissions, it will commit to the emission reductions associated with implementation of the 2004 Regional Transportation Plan and 2006 Regional Transportation Improvement Program which are imbedded in the emission projections. Similarly, the Ports of Los Angeles and Long Beach have authority they must utilize to assist in the implementation of various strategies if the region is to attain clean air by federal deadlines.*

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

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

Final Socioeconomic Report for the Final 2012 AQMP

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

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

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

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

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

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

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

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

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

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

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

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

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

Localized Cumulative Impacts

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

Projects with stationary sources located up to six miles from the proposed project site usually need to be considered by the cumulative analysis. The project owner requested that the SCAQMD identify potential new stationary sources within six miles of the Amended HBEP site. At the time when the PSA was prepared, SCAQMD had not provided a complete dataset. For the purposes of publishing a more complete PSA, the project owner proposed to use the cumulative sources (as shown below) previously submitted to the Energy Commission and approved for the licensed HBEP (HBEP 2016i).

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

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

After receiving additional responses from SCAQMD, the project owner proposed a revised cumulative sources list to the Energy Commission staff on August 25, 2016 (HBEP 2016ii). The project owner proposed to add five new sources and modify three previously included sources as follows:

- Orange County Sanitation District (Facility ID 17301)
  - A new abrasive blasting cabinet
  - Reduce emissions of the three previously included digester gas-fueled internal combustion engines (ICEs) due to addition of control equipment
- Huntington Beach City, Water Department (Facility ID 20231)
  - A new natural gas-fired emergency ICE
- Fabrica (Facility ID 95212)
  - A new plasma arc cutter
  - A new natural gas-fired ICE generator
- So Cal Holding, LLC (Facility ID 169754)
  - A new diesel-fueled emergency ICE

Staff reviewed and approved the revised cumulative sources list with minor revisions. On September 1, 2016, the project owner provided the revised cumulative impacts analysis and included the relevant communications between staff and the project owner regarding the minor revisions (HBEP 2016kk). The cumulative impact assessment shown below includes these updates.

Air Quality Table 22 shows that the Amended HBEP, along with other cumulative sources, would not cause new exceedances for 24-hour PM10, PM2.5, CO, NO_2, and SO_2. However, PM10 emissions from the Amended HBEP would be cumulatively considerable because they would contribute to the existing violations of annual PM10 ambient air quality standards.

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

Since the Amended HBEP is subject to PSD regulation for NO_2, CO and PM10, the project impacts must be below the PSD Significant Impact Levels (SILs) and applicable preconstruction monitoring thresholds for these pollutants or an increments analysis and/or preconstruction monitoring may be required. The CO, annual PM10, and annual NO_2 impacts from the Amended HBEP shown in **Air Quality Table 13** would be below corresponding SILs. The 24-hour PM10 impacts would also be less than the SILs with the project owner's refined analysis (HBEP 2015h) and a permit condition (SCAQMD condition C1.9 [**AQ-26**]) to limit the operating parameters of the project, as agreed to by the project owner. Therefore, no additional PSD analysis for 24-hour PM10 is required. However, the maximum 1-hour NO_2 impacts would exceed the applicable NO_2 SIL (7.52 $\mu g/m^3$), so an increments analysis is required for NO_2 impacts. The SCAQMD and U.S. EPA identified following sources to include in the 1-hour NO_2 cumulative analysis:

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

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

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

Pollutant	Averaging Time	Modeled Impact	Background	Total	Limiting Standard	Percent of Standard
PM10	24 hour	4.98 [e]	45	49.98	50	99.97
	Annual	0.64	**24.2**	**24.8**	**20**	**124**
PM2.5	24 hour [a]	4.98 [e]	27.8	32.8	35	94
	Annual	0.64	11.34	11.98	12	99.9
CO	1 hour	630.6	3,450	4,080.6	23,000	18
	8 hour	149.0	2,222	2,371.0	10,000	24
NO_2 [b]	State 1 hour	134.1	142.6	276.7	339	82
	Federal 1 hour [c]	--	--	144.8	188	77
	Annual	3.35	22	25.3	57	44
SO_2	State 1 hour	6.0	23.1	29.1	655	4
	Federal 1 hour [d]	6.0	10.5	16.5	196	8
	24 hour	1.7	3.7	5.4	105	5

Source: HBEP 2016kk and independent staff analysis
Notes:
[a] Total predicted concentration for the federal 24-hour PM2.5 standard is the maximum modeled concentration combined with the 3-year maximum of 98th percentile background concentrations.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 and 0.75 respectively.
[c] Total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average 98th percentile daily modeled concentration paired with the 3-year average of 98th percentile seasonal hour-of-day background concentrations.
[d] Total predicted concentration for the federal 1-hour SO_2 standard is the maximum modeled concentration combined with the 3-year maximum of 99th percentile background concentrations.
[e] The project owner performed a refined analysis assuming that one GE 7FA.05 turbine would operate at 44 percent load (minimum load) for 24 hours per day and the other GE 7FA.05 turbine would operate 20 hours per day at 44 percent load and 4 hours per day at 75 percent load (average load).

Air Quality Table 23
Amended HBEP, Federal 1-hour NO_2 Impacts from Cumulative Sources (μg/m^3)

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

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

Environmental Justice Impacts

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

RESPONSE TO PSA COMMENTS

Staff received Air Quality related comments from Mr. Mike Trelles (PB 2016a), City of Huntington Beach (Department of Planning and Building [CHB 2016b]), and the project owner (HBEP 2016cc). Responses to the Air Quality related comments are provided below and incorporated in the text where appropriate:

Mike Trelles' Comment:
"During the demolition, will any hazardous material or particulates get exposed to the air, with an almost constant breeze is there a potential of those dangers going air born?"

Staff Response:
The **Public Health** section analyzed the emissions and impacts of hazardous materials during construction/demolition activities such as airborne emissions from handling asbestos-containing materials (see more details in the **Public Health** and **Waste** sections). The Air Quality section analyzes criteria pollutants emissions, including particulate matter, released into the air during construction/demolition activities. Staff proposes Conditions of Certification **AQ-SC1** through **AQ-SC6** to mitigate these construction/demolition impacts. Staff expects that compliance with these conditions would mitigate adverse air quality impacts during construction/demolition of the Amended HBEP such that any criteria emissions leaving the project's boundaries would be less than significant and therefore protect air quality.

City of Huntington Beach (Department of Planning and Building) Comment:
Page 4.1-2: "The CEC should require complete removal of Units 1 and 2 rather than rely on voluntary removal as described in the PSA. Additionally, the City believes the CEC should require removal of Units 3 and 4 prior to operation of any new portion of the power plant."

Staff Response:
Although the decommissioning of Units 1 and 2 is likely for OTC Policy and Rule 1304(a)(2) compliance, their demolition and removal is voluntary. However, staff evaluated the Air Quality impacts due to demolition of Units 1 and 2 (to the turbine deck as proposed by the project owner) with simultaneous operation of the Amended HBEP (see more details in the "**B. Amended HBEP operation with simultaneous demolition of HBGS Units 1 and 2**" section of this analysis).

The construction/demolition scope and commercial operation schedule was proposed by the project owner, and modification of the scope and schedule is not required for staff's Air Quality analysis. Staff believes that Units 3 and 4, which were permanently modified and now operate as synchronous condensers, may still be needed to provide grid stability until the new combined-cycle power block becomes commercially available. Nevertheless, staff has fully analyzed the project impacts with the project owner proposed scope and schedule. Staff evaluated the Air Quality impacts due to demolition of Units 3 and 4 with simultaneous operation of the new combined-cycle power block and operation of existing HBGS Unit 2 (see more details in the "**C. Combined-cycle power block operation with simultaneous demolition of HBGS Units 3 and 4, and operation of HBGS Unit 2**" section of this analysis).

Project Owner's Comment:
Page 4.1-5, Air Quality Table 1: Please revise the emission limits for Title 40 Code of Federal Regulations Part 60, Subpart KKKK to the correct limits: 15 parts per million by volume corrected to 15 percent oxygen for oxides of nitrogen (NOx) or 0.43 pounds of NOx per megawatt-hour (lb/MWh) and a sulfur dioxide (SO_2) emission limit of 0.90 lb of SO_2/MWh.

Staff Response:
Staff agrees with the comment and Air Quality Table 1 has been revised accordingly.

Project Owner's Comments:
Page 4.1-22, Air Quality Table 5: Project Owner noted the following inconsistencies in the background concentrations presented in this table:

- *The 2014 federal 1-hour nitrogen dioxide (NO_2) value should be 0.0537 parts per million (ppm) instead of 0.0547 ppm.*
- *The 2011 1-hour CO value should be 2.9 ppm instead of 3 ppm.*
- *The 2014 1-hour CO value should be 2.7 ppm instead of 3 ppm.*
- *The 2009 federal 1-hour sulfur dioxide (SO_2) value should be 0.006 ppm instead of 0.004 ppm.*
- *The 2010 federal 1-hour SO_2 value should be 0.006 ppm instead of 0.002 ppm.*
- *The 2011 24-hour SO_2 value should be 0.002 ppm instead of 0.001 ppm.*

Staff Response:
The Energy Commission 2014 Final Staff Assessment (FSA [CEC 2014d]) for the licensed HBEP included background data from 2007 to 2012. Staff has double checked the 2009 to 2012 background data and made corresponding changes in **Air Quality Table 5** as suggested by the project owner. These changes (in 2009 to 2011 data) do not affect the staff recommended background data as shown in **Air Quality Table 6** (which are based on 2012 to 2014 data) or other Air Quality tables where the staff recommended background data are used.

For the 2013 and 2014 data, staff compared data from ARB, SCAQMD, and the U.S. EPA (ARB 2016c, SCAQMD 2016, and U.S. EPA 2016c). To be conservative, staff used the highest values wherever there are inconsistencies between these data sources. The 2014 federal 1-hour NO_2 value of 0.0547 ppm that staff used was from ARB 2016c, while the project owner suggested value of 0.0537 ppm was from SCAQMD 2016. Similarly, the 2014 1-hour CO value of 3 ppm that staff used was from SCAQMD 2016, while the project owner suggested value of 2.7 ppm was from U.S. EPA 2016c. Staff believes that the values staff used are more conservative than the project owner suggested values. Therefore, staff has not changed the 2014 federal 1-hour NO_2 and 1-hour CO data in **Air Quality Table 5**.

Project Owner's Comment:
Page 4.1-23, Air Quality Table 6: The 24-hour PM2.5, federal 1-hour SO_2, and federal 1-hour NO_2 background concentrations should be 3-year averages rather than 3-year maximums. Further, based on the CO values presented in Air Quality Table 5, the 3-year maximum 1-hour and 8-hour CO background concentrations should be 3,436 μg/m^3 and 2,290 μg/m^3, respectively.

Staff Response:
The federal 24-hour PM2.5, federal 1-hour SO_2, and federal 1-hour NO_2 standards are based on 98th/99th percentiles averaged over 3 years. To be conservative, staff used the maximum of the 98th/99th percentile values over the last three years of available data as the recommended background data, instead of the 3-year averages. Even with such conservative analysis, staff did not find that the Amended HBEP would cause any new violation of the federal 24-hour PM2.5, federal 1-hour SO_2, or federal 1-hour NO_2 standards. Using the 3-year averages instead of 3-year maximums would reduce the total impacts, but would not change the conclusions regarding the impacts of the Amended HBEP. In addition, the federal 1-hour NO_2 impacts were evaluated pairing the modeled project impacts with the 3-year average of 98th percentile seasonal hour-of-day background concentrations provided by SCAQMD. The staff-recommended federal 1-hour NO_2 background shown in **Air Quality Table 6** was not directly used in the impacts tables. Based on the above reasons, staff does not believe it is necessary to change the background concentrations for these federal standards in **Air Quality Table 6**. Staff has added a note under **Air Quality Table 6** and revised notes under the impacts tables indicating that staff used 3-year maximums instead of 3-year averages.

For the CO background concentrations, the difference between the staff-recommended values and the project owner suggested values is just a matter of precision. The CO background concentrations are well below the corresponding standards. Changing the CO background concentrations would not affect the conclusions regarding the impacts of the project. Staff does not believe it is necessary to change the CO background concentrations as suggested by the project owner.

Project Owner's Comments:
Page 4.1-28, Air Quality Table 9: In the Alamitos Energy Center permit application (Facility ID 115394), the South Coast Air Quality Management District ("District" or "SCAQMD") accepted an oil/water separator ("OWS") emission factor of 0.00002 pounds of volatile organic compounds (VOC) per 1,000 gallons of throughput. Using this emission factor for the Amended HBEP OWS results in revised emissions of 0.017 pounds per year for OWS 1 and 0.0022 pounds per year for OWS 2, or 0.0000022 pounds per hour (lbs/hr) for both OWS units annualized over 8,760 hours per year. This may warrant a change to the offsets described on PSA page 4.1-13.

Page 4.1-30, Air Quality Table 11: Using the revised OWS emission factor described in the comment regarding Air Quality Table 9 above results in revised emissions of 0.0000096 tons per year for both OWS units.

Staff Response:
The FDOC determined that the original OWS calculations presented by AES in the Amended HBEP application are deemed representative of the VOC emissions from the equipment. A change to the emissions methodology is not warranted at this late stage in the permitting process regardless of what was accepted for Alamitos. To be consistent with the FDOC, staff did not change the emissions of the OWS.

Project Owner's Comments:
Page 4.1-32, Air Quality Table 12: The modeled impact for 24-hour PM2.5 is shown as 4.3 µg/m^3, but Table 5.1-21 of the revised Petition to Amend (PTA) showed a value of 3.4 µg/m^3.

Page 4.1-40, Air Quality Table 13: The modeled impact for 24-hour PM2.5 is shown as 5.1 µg/m^3, but Table 5.1-24 of the revised PTA showed a value of 3.04 µg/m^3. In addition, the modeled impact for federal 1-hour SO_2 is shown as 5.8 µg/m^3, but Table 5.1-24 of the revised PTA showed a value of 4.86 µg/m^3.

Page 4.1-52, Air Quality Table 18: The modeled impact for 24-hour PM2.5 is shown as 5.1 µg/m^3, but Table 5.1-35 of the revised PTA showed a value of 3.15 µg/m^3. In addition, the modeled impact for federal 1-hour SO_2 is shown as 5.8 µg/m^3, but Table 5.1-35 of the revised PTA showed a value of 4.86 µg/m^3.

Page 4.1-53, Air Quality Table 19: The modeled impact for 24-hour PM2.5 is shown as 5.1 µg/m^3, but Table 5.1-36 of the revised PTA showed a value of 3.08 µg/m^3. In addition, the modeled impact for federal 1-hour SO_2 is shown as 5.8 µg/m^3, but Table 5.1-36 of the revised PTA showed a value of 4.87 µg/m^3.

Page 4.1-54, Air Quality Table 20: The modeled impact for 24-hour PM2.5 is shown as 5.1 µg/m^3, but Table 5.1-37 of the revised PTA showed a value of 2.97 µg/m^3. In addition, the modeled impact for federal 1-hour SO_2 is shown as 5.8 µg/m^3, but Table 5.1-37 of the revised PTA showed a value of 4.79 µg/m^3.

Page 4.1-55, Air Quality Table 21: The modeled impact for 24-hour PM2.5 is shown as 4.4 μg/m^3, but Table 5.1-38 of the revised PTA showed a value of 3.62 μg/m^3. In addition, the modeled impact for federal 1-hour SO_2 is shown as 4.3 μg/m^3, but Table 5.1-38 of the revised PTA showed a value of 0.95 μg/m^3.

Page 4.1-64, Air Quality Table 22: The modeled impact for 24-hour PM2.5 is shown as 5.1 μg/m^3, but Table 5.1-40 of the revised PTA showed a value of 3.05 μg/m^3. In addition, the modeled impact for federal 1-hour SO_2 is shown as 6.0 μg/m^3, but Table 5.1-40 of the revised PTA showed a value of 5.03 μg/m^3.

Staff Response:
As indicated in the notes under each of the impacts tables mentioned by the project owner, staff used the maximum modeled impacts for the 24-hour PM2.5 and federal 1-hour SO_2 standards. The project owner suggested using 5-year averages of the 98th/99th percentiles of modeled impacts. The U.S. EPA's March 23, 2010 memorandum regarding "Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS" noted that combining the 98th percentile monitored value with the 98th percentile modeled concentrations could result in a value that is below the 98th percentile of the combined cumulative distribution and would, therefore, not be protective of the NAAQS. In order to avoid possible underestimation of the total impacts, staff used the maximum modeled impacts for 24-hour PM2.5 and federal 1-hour SO_2 with the maximum of 98th/99th percentile values over the last three years of available data to compute the total impacts. Staff believes that this approach is conservative and no further justification is needed. Even with this conservative approach, staff showed that the Amended HBEP would not cause any new violation of the 24-hour PM2.5 and federal 1-hour SO_2 standards. Using the data suggested by the project owner would not change staff's determination regarding compliance with the 24-hour PM2.5 and federal 1-hour SO_2 impacts and therefore there is no need to make the changes suggested by the project owner.

Project Owner's Comments:
Page 4.1-37, 4th paragraph: Using the same approach for PM2.5 as Staff used for respirable particulate matter (PM10), the Project Owner calculated a necessary emission reduction value of 0.14 pounds per day (lbs/day) PM2.5 instead of 0.17 lbs/day. The calculations are as follows:

> *Emission Reduction (lbs/day) = Emission Rate (lbs/hr) x 24 hours per day – Daily Emission Rate (lbs/day) x (12 μg/m^3 – Ambient Background [μg/m^3]) / Modeled Impact (μg/m^3) = 0.033 lbs/hr x 24 – (0.033 lbs/hr x 24) x (12 μg/m^3 – 11.34 μg/m^3) / 0.8 μg/m^3 = 0.14 lbs/day*

Page 4.1-76, COC AQ-SC6: The emission reduction required for PM2.5 should be revised to 0.14 lbs/day per the comment provided for Page 4.1-37.

Staff Response:
The calculation method that the project owner suggested is correct. Staff's calculation used the modeled impact of 0.84707 $\mu g/m^3$ directly from the modeling files, which has more significant digits than the 0.8 $\mu g/m^3$ value shown in the project owner's calculation. Staff's calculation is more conservative than the project owner suggested calculation. Staff does not believe the required amount of PM2.5 emission reduction shown on page 4.1-37 or in **AQ-SC6** should be changed. As shown by the approved Construction Particulate Matter Mitigation Plan, the project owner can easily provide the additional 0.03 lbs/day of reduction needed due to the more conservative calculation.

Project Owner's Comment:
Page 4.1-48, Air Quality Table 17: The title of this table and text preceding this table continue to indicate that the emissions presented are 30-day averages. However, these emissions coincide with data from PDOC Tables C.6 and C.7, which are annual emissions.

Staff Response:
The VOC and PM10 mitigation are expressed as 30-day average lbs/day, while the NOx and SOx mitigation are expressed as lbs/year. Staff has changed the title and the header row of the table as well as the corresponding text.

Project Owner's Comment:
Page 4.1-53, last paragraph: This text indicates that demolition of Huntington Beach Generating Station (HBGS) Units 3 and 4 will last from the 1st/2nd quarter of 2020 to the 4th quarter of 2021. The construction schedule presented in the revised PTA indicates it will last until the 1st/2nd quarter of 2022.

Staff Response:
A follow-up email from Jerry Salamy, project manager at CH2M HILL, dated November 29, 2016 (HBEP 2016ss) clarified that demolition of Units 3 and 4 will last through the end of 2021. Therefore, staff did not make any changes to the demolition schedule.

Project Owner's Comment:
Page 4.1-77, COC AQ-SC9: Project Owner has already purchased 5 lbs/day of VOC and 5 lbs/day of PM10 Emission Reduction Credits ("ERCs") for the Amended HBEP. SCAQMD Rule 1303(b)(2) requires the Executive Officer of the SCAQMD to deny a Permit to Construct for any new or modified source which results in a net emission increase of any nonattainment air contaminant at a facility, unless emission increases are offset by either Emission Reduction Credits, or by allocations from the Priority Reserve, or by allocations from the Offset Budget. If the SCAQMD does not issue a Permit to Construct, the Project Owner cannot commence with construction of the HBEP. Since it is possible that the specific amount of ERCs required may change prior to the issuance of the Permit to Construct from the SCAQMD, based on either the comments provided above regarding the oil/water separator or any change in equipment based on final engineering design, it will require a Petition to Amend COC AQ-SC9 if specific ERC amounts are listed. Based on the foregoing, Project Owner requests Condition AQ-SC9 be revised as proposed below:

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

~~The project owner shall provide an ERC list and surrender the ERCs as required by the District. The project owner shall request CPM approval for any substitutions, modifications, or additions to the ERCs. The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, and that the requested change(s) will not cause the project to result in a significant environmental impact. The District must also confirm that each requested change is consistent with applicable federal and state laws and regulations.~~

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

Staff Response:
Staff believes that the specific quantities of the ERCs should be kept to ensure Energy Commission's enforceability on the ERCs. The quantities of the required ERCs in **AQ-SC9** are consistent with those shown in the FDOC as required by the SCAQMD. If the specific quantities of required ERCs need to be changed after the Energy Commission approves the Amended HBEP, the project owner could submit a Petition to Amend to make any needed changes to **AQ-SC9**. Staff also believes that the project owner should provide the ERC list to the Energy Commission and request CPM approval for any substitutions, modifications, or additions to the ERCs, so that CPM can maintain an updated list of ERCs for the project. Therefore, staff did not make the requested changes in **AQ-SC9**.

Project Owner's Comment:
Page 4.1-85 - 4.1-86, COC AQ-22: Staff should be advised that Project Owner commented on this and other Conditions in the comments on the PDOC submitted to the SCAQMD on July 11, 2016 (TN# 212278 [HBEP 2016bb]). Project Owner requests that any changes to AQ-22, and any other Air Quality Condition made by the District and included in the FDOC, be reflected in the FSA (and Final Decision).

Staff Response:
Staff has made changes in the conditions of certification to match FDOC conditions.

PROPOSED FINDINGS

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

1. The Amended HBEP would be located in the SCAB and within the SCAQMD.

2. The area where the Amended 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/unclassified for state and federal CO, NO_2 and SO_2 standards.

3. The project construction impacts would contribute to existing violations of ozone, PM10, and PM2.5 ambient air quality standards. Staff recommends Conditions of Certification **AQ-SC1** to **AQ-SC6** to mitigate the construction-phase impacts of the project.

4. The project operation would neither cause new violations of CO, NO_2, or SO_2 ambient air quality standards nor contribute to existing violations for these pollutants. Therefore, the project's direct CO, NO_2, and SO_2 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 NOx RECLAIM Trading Credits (RTCs), volatile organic compound (VOC) offsets from the District's internal bank, and the VOC ERCs for the auxiliary boiler and the oil/water separators, would mitigate the ozone impact to a less than significant level.

6. The PM10 and PM2.5 emissions and the PM10/PM2.5 precursor emissions from the project would contribute to the existing violations of PM10 and PM2.5 ambient air quality standards. The District would offset the PM emissions from its internal bank to mitigate the PM10/PM2.5 impacts of the new gas turbines to a less than significant level. The project owner would surrender PM10 ERCs to the District to mitigate the impacts of the auxiliary boiler. The project owner is required to offset the SOx emissions with SOx RTCs. The offsets and ERCs/RTCs would be in sufficient quantities to satisfy Energy Commission staff's long-standing recommendation that all nonattainment pollutant and precursor emissions be offset at least one-to-one.

7. The SCAQMD has issued a FDOC finding that the Amended HBEP would comply with all applicable District rules and regulations for project operation. The District's FDOC conditions are included herein as Conditions of Certification **AQ-1** through **AQ-71**.

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 Amended HBEP will not result in any significant direct, indirect, or cumulative adverse impacts to air quality.

CONCLUSIONS AND RECOMMENDATIONS

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

- Construction and demolition impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff proposes to keep the approved Conditions of Certification **AQ-SC2** through **AQ-SC5** and revise **AQ-SC1** and **AQ-SC6** to mitigate the Amended HBEP's construction and demolition impacts. Due to the long construction/demolition period (120 months) and the complexity of construction/demolition activities, compliance with these conditions would be critical to reduce construction/demolition impacts.
- Operation of the project would comply with applicable SCAQMD rules and regulations, including New Source Review, BACT requirements, and requirements to offset emission increases. Staff proposes to keep the approved Conditions of Certification **AQ-SC7** and **AQ-SC8** to ensure that the license is amended as necessary to incorporate any future changes to the air quality permits and to ensure ongoing compliance during commissioning and routine operation through quarterly reports. Staff proposes a new Condition of Certification (**AQ-SC9**) to ensure that the emissions of the auxiliary boiler and the oil/water separators would be mitigated with the quantity of SCAQMD offsets recommended by the SCAQMD and Energy Commission staff and to ensure agency consultation if substitutions are made to the credits. Staff proposes a new Condition of Certification (**AQ-SC10**) to establish appropriate guidelines on what would be considered a significant change to a condition of certification and to allow the CPM to approve administrative changes. Staff proposes to delete the approved Conditions of Certification **AQ-1** through **AQ-43** for the licensed HBEP and recommends the inclusion of the SCAQMD's new FDOC conditions (SCAQMD 2016g) as new Conditions of Certification **AQ-1** through **AQ-71** for the Amended HBEP.
- Implementation of the conditions of certification, and the air quality conditions and practices described in the analysis would reduce potential adverse impacts to insignificant levels and ensure that the project's emissions are mitigated to less than significant.
- With the adoption of the attached conditions of certification, the Amended HBEP would comply with all applicable laws, ordinances, regulations, and standards related to air quality as described in pertinent portions of this analysis.

PROPOSED CONDITIONS OF CERTIFICATION

Staff has proposed modifications to the Air Quality conditions of certification. Most of the approved Conditions of Certification **AQ-1** through **AQ-43** for the licensed HBEP don't apply to the Amended HBEP or need to be substantially revised to be applicable. In order to avoid confusion and too many edits in the conditions, staff proposes to delete the approved Conditions of Certification **AQ-1** through **AQ-43** for the licensed HBEP completely and recommends the inclusion of the SCAQMD's new conditions as new Conditions of Certification **AQ-1** through **AQ-71** for the Amended HBEP. These changes incorporate the conditions of certification consistent in the current SCAQMD

Determination of Compliance. Staff understands that **AQ-1** (SCAQMD condition F2.1) and **AQ-2** (SCAQMD condition F52.1) include limits and requirements for the existing HBGS units that are not jurisdictional to the Energy Commission. However, staff incorporated those limits and requirements for the non-jurisdictional units to make sure the amended facility complies with LORS during the transitional period before the existing units are retired and new units become available.

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

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

Revised Energy Commission COCs Numbering	SCAQMD Numbering	Approved Energy Commission COCs Numbering	Staff Proposed Modifications and Justification
AQ-SC1	Not Applicable	**AQ-SC1**	Staff proposes minor modifications in the last sentence of this condition to be consistent with the language approved for other siting projects.
AQ-SC2 through **AQ-SC5**	Not Applicable	**AQ-SC2** through **AQ-SC5**	No change
AQ-SC6	Not Applicable	**AQ-SC6**	Revise according to the construction emissions and impacts for the Amended HBEP.
AQ-SC7, **AQ-SC8**	Not Applicable	**AQ-SC7**, **AQ-SC8**	No change
AQ-SC9	Not Applicable	None	New. Staff proposes this new condition to ensure that the emissions of the auxiliary boiler and the oil/water separators would be mitigated with the quantity of SCAQMD offsets recommended by the SCAQMD and Energy Commission staff and to ensure agency consultation if substitutions are made to the credits.
AQ-SC10	Not Applicable	None	New. Staff proposes this new condition to allow the CPM to approve administrative changes.
AQ-1	F2.1	None	New
AQ-2	F52.1	None	New
AQ-3	F52.2	None	New
AQ-4	F52.3	None	New
AQ-5	A63.6	None	New

Revised Energy Commission COCs Numbering	SCAQMD Numbering	Approved Energy Commission COCs Numbering	Staff Proposed Modifications and Justification
AQ-6	A63.7	None	New
AQ-7	A63.8	None	New
AQ-8	A63.9	None	New
AQ-9	A63.10	None	New
AQ-10	A99.4	None	New
AQ-11	A99.5	None	New
AQ-12	A195.6	None	New
AQ-13	A195.7	None	New
AQ-14	A195.8	None	New
AQ-15	A195.9	None	New
AQ-16	A195.10	None	New
AQ-17	A195.11	None	New
AQ-18	A195.12	None	New
AQ-19	A195.13	None	New
AQ-20	A195.14	None	New
AQ-21	A195.15	None	New
AQ-22	A327.1	None	New
AQ-23	B61.1	None	New
AQ-24	C1.7	None	New
AQ-25	C1.8	None	New
AQ-26	C1.9	None	New
AQ-27	C1.10	None	New
AQ-28	C1.11	None	New
AQ-29	C1.12	None	New
AQ-30	C1.13	None	New
AQ-31	C1.14	None	New
AQ-32	C157.1	None	New
AQ-33	D12.7	None	New
AQ-34	D12.8	None	New
AQ-35	D12.9	None	New
AQ-36	D12.10	None	New
AQ-37	D12.11	None	New
AQ-38	D12.12	None	New
AQ-39	D12.13	None	New
AQ-40	D12.14	None	New
AQ-41	D12.15	None	New
AQ-42	D12.16	None	New
AQ-43	D12.17	None	New
AQ-44	D29.5	None	New

Revised Energy Commission COCs Numbering	SCAQMD Numbering	Approved Energy Commission COCs Numbering	Staff Proposed Modifications and Justification
AQ-45	D29.6	None	New
AQ-46	D29.7	None	New
AQ-47	D29.8	None	New
AQ-48	D29.9	None	New
AQ-49	D82.3	None	New
AQ-50	D82.4	None	New
AQ-51	D82.5	None	New
AQ-52	E144.1	None	New
AQ-53	E193.3	None	New
AQ-54	E193.4	None	New
AQ-55	E193.5	None	New
AQ-56	E193.6	None	New
AQ-57	E193.7	None	New
AQ-58	E193.8	None	New
AQ-59	E448.1	None	New
AQ-60	E448.2	None	New
AQ-61	E448.3	None	New
AQ-62	I297.1	None	New
AQ-63	I297.2	None	New
AQ-64	I297.3	None	New
AQ-65	I298.1	None	New
AQ-66	I298.2	None	New
AQ-67	I298.3	None	New
AQ-68	K40.3	None	New
AQ-69	K40.4	None	New
AQ-70	K67.5	None	New
AQ-71	K67.6	None	New
None	None	**AQ-1** through **AQ-43**	Delete. Staff proposes to delete the approved COCs **AQ-1** through **AQ-43** for the licensed HBEP because most of them don't apply to the Amended HBEP or need to be substantially revised to be applicable.
None	F9.1, F14.1, F16.1, F18.1, and F24.1	None	These SCAQMD conditions do not apply to the Amended HBEP project. Therefore, staff does not propose to add them as new COCs.

STAFF-RECOMMENDED CONDITIONS OF CERTIFICATION

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

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM)

The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with Conditions **AQ-SC3, AQ-SC4** and **AQ-SC5** for the entire duration of project site construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM delegates. The AQCMM and AQCMM delegates shall have full access to all areas of construction on the project site, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM delegates may have other responsibilities in addition to those described in this condition. The AQCMM ~~may be replaced only after compliance with the selection process outlined below.~~ <u>**shall not be terminated without written consent**</u> of the compliance project manager (CPM).

<u>**Verification**</u>**:** 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**.

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

AQ-SC3 Construction Fugitive Dust Control

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

The AQCMM shall submit documentation to the CPM in each monthly compliance report (MCR) that demonstrates compliance with the Air Quality Construction Mitigation Plan (AQCMP) mitigation measures for purposes of minimizing fugitive dust emission creation from construction activities and preventing all fugitive dust plumes from leaving the project's boundary. The following fugitive dust mitigation measures shall be included in the AQCMP required by **AQ-SC2**, and any deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

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

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

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

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

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

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

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

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

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

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

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

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

M. When bulk materials are transported offsite, all materials that have the potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least two feet of freeboard.

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

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

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

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

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

AQ-SC4 Dust Plume Response Requirement

The AQCMM or an AQCMM delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported off the project site and within 400 feet upwind of any regularly occupied structures not owned by the project owner indicates that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified. The AQCMM or delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

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

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

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

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 air quality-related complaints filed with the district or facility representatives in relation to project construction; and

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

AQ-SC5 Diesel-Fueled Engine Control

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G. Construction equipment will employ electric motors when feasible.

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

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

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

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

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

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

AQ-SC6 Construction Particulate Matter Mitigation Plan

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

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

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

The project owner shall provide the CPM copies of all district issued Permit-to-Construct (PTC) and Permit-to-Operate (PTO) documents for the facility. The project owner shall submit an amendment request to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the district or U.S. EPA, and any revised permit issued by the district or U.S. EPA, for the project.

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

AQ-SC8 Quarterly Operation Reports

The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with the conditions of certification herein. The Quarterly Operation Report shall specifically note or highlight incidences of noncompliance.

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

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

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

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

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

AQ-SC10 The project owner shall comply with all staff (AQ-SC) and district (AQ) conditions of certification. The CPM, in consultation with the District, may approve any change to a condition of certification regarding air quality, as a staff approved modification, provided that: (1) the project remains in compliance with all applicable laws, ordinances, regulations, and standards, (2) the requested change clearly will not cause the project to result in a significant environmental impact, (3) no additional mitigation or offsets will be required as a result of the change, (4) no existing daily, quarterly, or annual permit limit will be exceeded as a result of the change, and (5) no increase in any daily, quarterly, or annual permit limit will be necessary as a result of the change.

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

DISTRICT ~~FINAL DETERMINATION OF COMPLIANCE~~ CONDITIONS

The following SCAQMD Conditions (**AQ-1** to **AQ-7**~~143~~**71**) apply to **various units as identified where needed** ~~each unit of equipment and the proposed HBEP facility as a whole.~~

FACILITY CONDITIONS

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

CONTAMINANT	EMISSIONS LIMIT
PM2.5	Less than 100 TONS IN ANY ONE YEAR

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

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

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

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

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

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

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

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

Within 30 calendar days of actual shutdown, or by no later than November 1, 2019, AES shall provide SCAQMD with a notarized statement that HB Beach Boiler 1 and RB Boiler 7 are permanently shutdown and that any 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.

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

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

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

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

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

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

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

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

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

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

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

AQ-4 This facility is subject to the applicable requirements of the following rules or regulation(s):

Rule 1304.1 Electric Generating Fee for Use of Offset Exemption

The owner/operator shall submit the annual payment for PM10 and VOC, calculated in accordance with the rule and approved by the Executive Officer, on or before the anniversary date of the commencement of operation. The owner or operator may elect to switch to the single payment option upon submittal of a written request to the Executive Officer.

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

DEVICE CONDITIONS

A. Emission Limits

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

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

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

The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 8.86 lbs/mmcf, PM10: 5.11 lbs/mmcf, and CO: 61.18 lbs/mmcf.

The combined-cycle turbines are subject to this condition.

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

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

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 6,324 LBS IN ANY ONE MONTH
CO	Less than or equal to 24,720 LBS IN ANY ONE MONTH
VOC	Less than or equal to 7,611 LBS IN ANY ONE MONTH

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

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

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

The combined-cycle turbines are subject to this condition.

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

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

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 4,643 LBS IN ANY ONE MONTH
CO	Less than or equal to 5,545 LBS IN ANY ONE MONTH
VOC	Less than or equal to 1,972 LBS IN ANY ONE MONTH

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

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

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

The simple-cycle turbines are subject to this condition.

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

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

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

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

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

The simple-cycle turbines are subject to this condition.

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

AQ-9 The project owner shall limit emissions from this equipment as follows:

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

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

The auxiliary boiler is subject to this condition.

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

AQ-10 The 16.66 LBS/MMSCF NOx emission limit(s) shall only apply during the first year of operation prior to CEMS certification for reporting NOx emissions.

The combined-cycle turbines are subject to this condition.

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

AQ-11 The 25.11 LBS/MMSCF NOx emission limit(s) shall only apply during the first year of operation prior to CEMS certification for reporting NOx emissions.

The simple-cycle turbines are subject to this condition.

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

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

The combined-cycle turbines are subject to this condition.

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

AQ-13 The 1.5 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

The combined-cycle turbines are subject to this condition.

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

AQ-14 The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

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

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

AQ-15 The 1,000 LBS/MW-HR CO_2 emission limit(s) is averaged over a rolling 12 operating month basis. The limit shall only apply if the turbine supplies more than 1,519,500 MWh net electrical output to a utility distribution system over a rolling 12 operating month basis and a 3 year rolling average basis.

The combined-cycle turbines are subject to this condition.

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

AQ-16 The 5.0 ppmv NH_3 emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry basis. The project owner shall calculate and continuously record the NH_3 slip concentration using the following:

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

where,

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

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

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

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

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

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

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

Verification: The project owner shall include computed hourly ammonia slip concentrations as part of the Quarterly Operation Reports (AQ-SC8). Compliance with the ammonia slip limit shall be verified by the next scheduled ammonia source tests required in AQ-44 or AQ-45 or District approved alternative method.

AQ-17 The 2.5 PPMV NOx emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

The simple-cycle turbines are subject to this condition.

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

AQ-18 The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

The simple-cycle turbines are subject to this condition.

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

AQ-19 The 5.0 PPMV NOx emission limit(s) is averaged over 60 minutes at 3 percent O_2, dry. This limit shall not apply during boiler start ups.

The auxiliary boiler is subject to this condition.

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

AQ-20 The 50.0 PPMV CO emission limit(s) is averaged over 60 minutes at 3 percent O_2, dry. This limit shall not apply during boiler start ups.

The auxiliary boiler is subject to this condition.

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

AQ-21 The 5.0 ppmv NH_3 emission limit(s) is averaged over 60 minutes at 3 percent O_2, dry basis. The operator shall calculate and continuously record the NH_3 slip concentration using the following:

NH3 (ppmv) = [a–b*(c*1.2)/1E+06]*1E+06/b

where,

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

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

c = change in measured NOx across the SCR (ppmvd at 3 percent O_2)

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

The 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.

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

Verification: The project owner shall include the computed hourly ammonia slip concentrations as part of the Quarterly Operation Reports (AQ-SC8). Compliance with the ammonia slip limit shall be verified by the next scheduled ammonia source tests required in AQ-45 or AQ-47 or District approved alternative method.

AQ-22 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.

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

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

B. Material/Fuel Type Limits

AQ-23 The project owner shall not use natural gas containing the following specified compounds:

Compound	grain per 100 scf
H_2S greater than	0.25

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

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

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

C. Throughput or Operating Parameter Limits

AQ-24 The project owner shall limit the number of start-ups to no more than 62 in any one calendar month.

The number of cold start ups shall not exceed 15 per month, the number of non-cold start ups shall not exceed 47 per month. Additionally, the number of cold start ups shall not exceed 80 per year, and the number of non-cold start ups shall not exceed 420 per year.

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

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

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

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

The combined-cycle turbines are subject to this condition.

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

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

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

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

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

The combined-cycle turbines are subject to this condition.

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

AQ-26 The project owner shall limit the operating time to no more than 6640 hour(s) in any one calendar year.

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

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

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

The combined-cycle turbines are subject to this condition.

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

AQ-27 The project owner shall limit the number of start-ups to no more than 62 in any one calendar month.

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

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

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

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

The simple-cycle turbines are subject to this condition.

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

AQ-28 The project owner shall limit the number of shut-downs to no more than 62 in any one calendar month.

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

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

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

The simple-cycle turbines are subject to this condition.

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

AQ-29 The project owner shall limit the operating time to no more than 2001 hour(s) in any one calendar year.

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

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

The simple-cycle turbines are subject to this condition.

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

AQ-30 The project owner shall limit the number of start-ups to no more than 10 in any one calendar month.

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

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

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

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

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

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

The auxiliary boiler is subject to this condition.

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

AQ-31 The project owner shall limit the heat input to no more than 189,155 MMBtu in any one calendar year.

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

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

The auxiliary boiler is subject to this condition.

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

AQ-32 The project owner shall install and maintain a pressure relief valve set at 50 psig.

The ammonia storage tanks are subject to this condition.

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

D. Monitoring/Testing Requirements

AQ-33 The project owner shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

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

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

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

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

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

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

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

AQ-35 The project owner shall install and maintain a(n) differential pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

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

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

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

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

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

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

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

AQ-37 The project owner shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

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

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

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

AQ-38 The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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

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

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

AQ-39 The project owner shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

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

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

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

AQ-40 The project owner shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

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

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

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

AQ-41 The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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

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

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

AQ-42 The project owner shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

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

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

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

AQ-43 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the CO Catalyst.

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

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

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

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

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

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

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

The test shall be conducted in accordance with an SCAQMD approved 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 3 load conditions, including within 5 percent of maximum, within 5 percent of minimum, and one intermediate load.

For natural gas fired turbines only, for the purpose of demonstrating compliance with BACT as determined by SCAQMD, the project owner shall use SCAQMD Method 25.3 modified as follows:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AQ-46 The project owner shall conduct source test(s) for the pollutant(s) identified below.

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

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

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

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

For natural gas fired turbines only, for the purpose of demonstrating compliance with BACT as determined by SCAQMD, the project owner shall use SCAQMD Method 25.3 modified as follows:

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

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

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

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

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

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

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

AQ-47 The project owner shall conduct source test(s) for the pollutant(s) identified below.

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

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

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

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

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

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

The auxiliary boiler is subject to this condition.

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

AQ-48 The project owner shall conduct source test(s) for the pollutant(s) identified below.

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

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

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

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

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

The auxiliary boiler is subject to this condition.

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

AQ-49 The project owner shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

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

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

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

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9%-%O_2 d)]* [(Qg*HHV)/10E6], where

1. K = $7.267*10^{-8}$ (lbs/scf)/ppm

2. Cco = Average of 4 consecutive 15 min. average CO concentrations, ppm

3. Fd = 8710 dscf/MMBTU natural gas

4. %O_2, d = Hourly average % by volume O_2 dry, corresponding to Cco

5. Qg = Fuel gas usage during the hour, scf/hr

6. HHV = Gross high heating value of the fuel gas, BTU/scf

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

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

AQ-50 The project owner shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

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

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start up and the provisional certification date of the CEMS, the operator shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).

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

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

AQ-51 The project owner shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 3 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the boiler, in accordance with approved SCAQMD REG XX CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the combined-cycle turbine commissioning and boiler construction period. During the interim period between the initial start up and the provisional certification date of the CEMS, the project owner shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).

The auxiliary boiler is subject to this condition.

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

E. Equipment Operation/Construction Requirements

AQ-52 The project owner shall vent this equipment, during filling, only to the vessel from which it is being filled.

The ammonia storage tanks are subject to this condition.

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

AQ-53 The project owner shall install this equipment according to the following requirements:

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment.

Construction of Phase 1 of the project (defined as the combined-cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.

Construction of Phase 2 of the project (defined as the simple-cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

The combined-cycle turbines, the simple-cycle turbines, the auxiliary boiler and their corresponding SCRs, CO Catalysts, and ammonia storage tanks are subject to this condition.

Verification: The project owner shall submit any permit extension granted by the permitting authority to the CPM within 15 days of receipt. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-54 The project owner shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

The combined-cycle turbines, the simple-cycle turbines, the auxiliary boiler and their corresponding SCRs, CO Catalysts, and ammonia storage tanks are subject to this condition.

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

AQ-55 The project owner shall install this equipment according to the following requirements:

Total commissioning hours shall not exceed 996 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 216 hours of operation for each turbine.

The project owner shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning.

The project owner shall provide SCAQMD with written notification of the initial start up date. Written records of commissioning, start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.

The combined-cycle turbines are subject to this condition.

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

AQ-56 The project owner shall upon completion of construction, operate and maintain this equipment according to the following specifications:

The project owner shall record the total net power generated in a calendar month in megawatt-hours.

The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

CO_2 = 60.009 * FF

Where, CO_2 is in tons and FF is the monthly fuel usage in millions standard cubic feet.

The project owner shall calculate and record the CO_2 emissions in pounds per net megawatt-hour on a 12-month rolling average. The CO_2 emissions from this equipment shall not exceed 873,035 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed 967.6 pounds per net MW-hour.

The project owner shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.

The combined-cycle turbines are subject to this condition.

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

AQ-57 The project owner shall install this equipment according to the following requirements:

Total commissioning hours shall not exceed 280 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 4 hours of operation for each turbine.

The project owner shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning.

The project owner shall provide SCAQMD with written notification of the initial start up date. Written records of commissioning, start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.

The simple-cycle turbines are subject to this condition.

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

AQ-58 The project owner shall upon completion of construction, operate and maintain this equipment according to the following specifications:

The project owner shall record the total net power generated in a calendar month in megawatt-hours.

The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

CO_2 = 60.009 * FF

Where, CO_2 is in tons and FF is the monthly fuel usage in millions standard cubic feet.

The project owner shall calculate and record the CO_2 emissions in pounds per net megawatt-hour on a 12-month rolling average. The CO_2 emissions from this equipment shall not exceed 103,576 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed 1378.0 pounds per net MW-hour.

The project owner shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.

The simple-cycle turbines are subject to this condition.

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

AQ-59 The project owner shall comply with the following requirements:

The total electricity output on a gross basis from combined-cycle turbines devices D115 and D124, and their common steam turbine shall not exceed 693.8 MW.

The gross electrical output shall be measured at the single generator serving each of the combined-cycle turbines, and the single generator serving the common steam turbine. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15 minute averaging time period.

The project owner shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

The combined-cycle turbines are subject to this condition.

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

AQ-60 The project owner shall comply with the following requirements:

The total electricity output on a gross basis from simple-cycle turbines devices D133 and D139 shall not exceed 201.6 MW.

The gross electrical output shall be measured at the single generator serving each of the simple-cycle turbines. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15 minute averaging time period.

The project owner shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

The simple-cycle turbines are subject to this condition.

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

AQ-61 The project owner shall comply with the following requirements:

This equipment shall not supply more than 43 percent of its potential electrical output or more than 376,200 MWh net electrical output to a utility distribution system on a 12 operating month rolling average and a 3 year rolling average basis

The project owner shall record and maintain written records of the amount of electricity supplied to the utility distribution system expressed as a percentage of the total potential electrical output of the turbine and shall make the records available to the Executive Officer upon request.

The simple-cycle turbines are subject to this condition.

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

I. Administrative

AQ-62 This equipment shall not be operated unless the facility holds 147,093 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-63 This equipment shall not be operated unless the facility holds 26,970 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-64 This equipment shall not be operated unless the facility holds 1,313 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-65 This equipment shall not be operated unless the facility holds 14,803 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 9,960 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The combined-cycle turbines are subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-66 This equipment shall not be operated unless the facility holds 1,660 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 1,201 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The simple-cycle turbines are subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

AQ-67 This equipment shall not be operated unless the facility holds 382 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 382 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (AQ-SC8).

K. Record Keeping/Reporting

AQ-68 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-44, AQ-45, and AQ-46 are conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

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

Verification: The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-69 The operator 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-45, AQ-47, and AQ-48 are conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 3 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), and the flue gas temperature under which the test was conducted.

The auxiliary boiler is subject to this condition.

Verification: The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-70 The project owner shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Commissioning hours and type of control and fuel use

Date, time, and duration of each start-up and shutdown, and the type of start up (cold or non-cold)

In addition to the requirements of a certified CEMS, natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification

Minute by minute data (NO_2 and O_2 concentration and fuel flow rate at a minimum) for each turbine start up and shutdown

Total annual power output in MWh

The combined-cycle turbines are subject to this condition.

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

AQ-71 The operator 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

In addition to the requirements of a certified CEMS, natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification

Minute by minute data (NO_2 and O_2 concentration and fuel flow rate at a minimum) for each turbine start up

Total annual power output in MWh

The simple-cycle turbines are subject to this condition.

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

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

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

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

~~For purposes of demonstrating compliance with the 100 tons per year limit the project owner shall sum the PM2.5 emissions for each of the major sources at this facility by calculating a 12 month rolling average using the calendar monthly fuel use data and following emission factors for each turbine PM2.5 = 3.36 lbs/mmcf with no duct firing and PM2.5 = 5.22 lbs/mmcf with duct firing, for Boiler 1 PM2.5 = 1.86 lbs/mmscf, for Boiler 2 PM2.5 = 2.1 lbs/mmscf.~~

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

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

~~[Rule 1325, 40CFR 51, Appendix S]~~

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

~~**AQ-2** This facility is subject to the applicable requirements of the following rules or regulations:~~

~~The facility shall submit a detailed retirement plan for the permanent shutdown of Huntington Beach (HB) Boilers 1 and 2 and Redondo Beach (RB) Boilers 6 and 8 describing in detail the steps and schedule that will be taken to render the boilers permanently inoperable. The retirement plan shall be submitted to SCAQMD within 60 days after the Permits to Construct for gas turbine Units 1A, 1B, 1C, 2A, 2B, and 2C are issued.~~

~~The retirement plan must be approved in writing by SCAQMD. AES shall not commence any construction of HB Boilers 1 and 2 and RB Boilers 6 and 8 repowering project equipment including gas turbines 1A, 1B, 1C, 2A, 2B, 2C, steam turbines 1 and 2, SCR/CO catalysts for gas turbines 1A, 1B, 1C, 2A, 2B, and 2C, or the oil water separator, before the retirement plan is approved in writing by SCAQMD. If SCAQMD notifies AES that the plan is not approvable, AES shall submit a revised plan addressing SCAQMD's concerns within 30 days.~~

~~Within 30 calendar days of actual shutdown, or by no later than December 31, 2018, AES shall provide SCAQMD with a notarized statement that HB Beach Boilers 1 and 2 and RB Boilers 6 and 8 are permanently shut down and that any restart or operation of the units shall require new Permits to Construct and be subject to all requirements of non-attainment new source review and the prevention of significant deterioration program.~~

~~AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of HB Boilers 1 and 2 and RB Boilers 6 and 8, or advise SCAQMD as soon practicable should AES undertake permanent shutdown prior to December 31, 2018.~~

~~AES shall cease operation of RB Boilers 6 and 8 within 90 calendar days of the first fire of Units 1A, 1B, or 1C, and AES shall cease operation of HB Boilers 1 and 2 within 90 calendar days of the first fire of Units 2A, 2B, or 2C.~~

~~Rule 1304 – Modeling and Offset Exemption]~~

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

~~**AQ-3**~~ ~~This facility is subject to the applicable requirements of the following rules or regulations:~~

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

~~The total CO2e emissions from all circuit breakers shall not exceed 6.8 tons per calendar year.~~

~~[Rule 1714]~~

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

~~**EACH GAS TURBINE**~~

~~**AQ-4**~~ ~~The project owner shall limit emission from this equipment as follows:~~

~~**CONTAMINANT**~~	~~**EMISSION LIMIT**~~
~~PM10~~	~~4,278.0 LBS IN ANY ONE MONTH~~
~~CO~~	~~12,776.2 LBS IN ANY ONE MONTH~~
~~VOC~~	~~7,487.2 LBS IN ANY ONE MONTH~~

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

~~The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 2.94 lbs/mmcf, PM10: 3.36 lbs/mmcf with no duct burner firing, 5.22 lbs/mmcf with duct burner firing.~~

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

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

~~The project owner shall limit the annual firing hours for each turbine to 6370 hours including no more than 470 hours with duct firing (this does not include start up and shutdown hours)~~

~~[Rule 1303 – Offsets]~~

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

~~**AQ-5** The project owner shall limit emission from this equipment as follows:~~

~~**CONTAMINANT**~~	~~**EMISSION LIMIT**~~
~~PM10~~	~~2,930 LBS IN ANY ONE MONTH~~
~~CO~~	~~112,882 LBS IN ANY ONE MONTH~~
~~VOC~~	~~14,121 LBS IN ANY ONE MONTH~~

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

~~The project owner shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 21.74 lbs/mmcf, PM10: 4.51 lbs/mmcf, and CO: 173.80 lbs/mmcf.~~

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

~~**AQ-6** The 12.75 LBS/MMCF NOx emission limits shall only apply during turbine operation prior to CEMS certification for reporting NOx emissions.~~

~~[Rule 2012]~~

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

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

~~[Rule 1703-PSD, Rule 2005]~~

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

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

~~[Rule 1703-PSD]~~

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

~~**AQ-9** The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O_2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.~~

~~[Rule 1303(a) – BACT, Rule 1303(b)(1) – Modeling, Rule 1303(b)(2) - Offsets]~~

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

~~**AQ-10** The 1100 lbs/net MWH CO2 limit is averaged over 12 rolling months. This limit only applies if the capacity factor of the unit is equal to or exceeds 60% on an annual basis.~~

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

~~**AQ-11** For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.~~

~~[Rule 475]~~

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

~~**AQ-12** The project owner shall not use natural gas containing the following specified compounds:~~

~~**Compound**~~	~~**Grains per 100 scf**~~
~~H_2S~~	~~Greater than 0.25~~

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

~~[Rule 1303(b) – Offset]~~

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

~~**AQ-13** The project owner shall limit the number of startups to no more than 90 in any one calendar month.~~

~~The number of cold start ups shall not exceed 5 per month, the number of warm start ups shall not exceed 25 per month, and the number of hot start ups shall not exceed 60 per month.~~

~~For the purposes of this condition:~~

~~A cold start up is defined as a startup which occurs after the steam turbine has been shut down for 49 hours or more. A cold start up shall not exceed 90 minutes. Emissions from a cold start up shall not exceed the following: NOx - 29 lbs., CO – 116 lbs., VOC – 28 lbs.~~

~~A warm start up is defined as a startup which occurs after the steam turbine has been shut down for 9 – 49 hours. A warm start up shall not exceed 32.5 minutes. Emissions from a warm start up shall not exceed the following: NOx - 17 lbs., CO – 46 lbs., VOC – 21 lbs.~~

~~A hot start up is defined as a startup which occurs after the steam turbine has been shut down for less than 9 hours. A hot start up shall not exceed 32.5 minutes. Emissions from a hot start up shall not exceed the following: NOx - 17 lbs., CO – 34 lbs., VOC – 21 lbs.~~

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

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

~~[Rule 2005]~~

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

~~**AQ-14**~~ ~~The project owner shall limit the number of shutdowns to no more than 90 in any one calendar month.~~

~~Shutdown time shall not exceed 10 minutes per shutdown. Emissions from a shutdown shall not exceed the following: NOx - 9 lbs., CO – 46 lbs., VOC – 31 lbs.~~

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

~~[Rule 2005]~~

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

~~**AQ-15**~~ ~~The project owner shall limit the power output of the plant to no more than 939 MWs. The 939 MW limit is based on the net power output.~~

~~The net electrical output shall be measured at the breaker of the transmission system interconnection point in the generation switchyard. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/-0.2 percent.~~

~~The net electrical output from each meter shall be recorded at the CEMS data acquisition system.~~

~~The project owner shall maintain records, for a minimum of five years, in a manner approved by the SCAQMD to demonstrate compliance with this condition.~~

~~[Rule 1304 - Modeling and Offset Exemption]~~

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

~~**AQ-16**~~ ~~The project owner shall limit the power output of the plant to no more than 972 MW gross.~~

~~The 972 MW limit is based on the gross power output.~~

~~The gross electrical output shall be measured at the each of the 8 generators.~~

~~The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/-0.2 percent.~~

~~The gross electrical output from generators shall be recorded at the CEMS data acquisition system.~~

~~The project owner shall maintain records, for a minimum of five years, in a manner approved by the SCAQMD to demonstrate compliance with this condition.~~

~~[Rule 1304 - Modeling and Offset Exemption]~~

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

AQ-17 ~~The project owner shall conduct source test(s) for the pollutant(s) identified below.~~

~~**Pollutant to be tested**~~	~~**Required Test Method(s)**~~	~~**Averaging Time**~~	~~**Test Location**~~
~~NOX emissions~~	~~District Method 100.1~~	~~1 hour~~	~~Outlet of the SCR~~
~~CO emissions~~	~~District Method 100.1~~	~~1 hour~~	~~Outlet of the SCR~~
~~SOX emissions~~	~~Approved District method~~	~~District approved averaging time~~	~~Fuel Sample~~
~~VOC emissions~~	~~Approved District method~~	~~1 hour~~	~~Outlet of the SCR~~
~~PM10 emissions~~	~~Approved District method~~	~~District approved averaging time~~	~~Outlet of the SCR~~
~~PM2.5~~	~~Approved District method~~	~~District approved averaging time~~	~~Outlet of the SCR~~
~~NH3 emissions~~	~~District method~~ ~~207.1 and 5.3 or EPA method 17~~	~~1 hour~~	~~Outlet of the SCR~~

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

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

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

~~The test shall be conducted when this equipment is operating at loads of 100 and 70 percent without duct firing, and 100 percent with duct firing.~~

~~For natural gas fired turbines only, volatile organic compound (VOC) compliance shall be demonstrated as follows: a) stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F. The use of this alternative method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The results shall be reported with two significant digits.~~

~~[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703-PSD, Rule 2005]~~

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

~~**AQ-18**~~ ~~The project owner shall conduct source test(s) for the pollutant(s) identified below.~~

~~**Pollutant to be tested**~~	~~**Required Test Method(s)**~~	~~**Aver aging Time**~~	~~**Test Location**~~
~~NH_3 emissions~~	~~District method 207.1 and 5.3 or EPA method 17~~	~~1 hour~~	~~Outlet of the SCR~~

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

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

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

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-19** The project owner shall conduct source test(s) for the pollutant(s) identified below.~~

~~**Pollutant to be tested**~~	~~**Required Test Method(s)**~~	~~**Averaging Time**~~	~~**Test Location**~~
~~SOX emissions~~	~~Approved District method~~	~~District approved averaging time~~	~~Fuel Sample~~
~~VOC emissions~~	~~Approved District method~~	~~1 hour~~	~~Outlet of the SCR~~
~~PM10 emissions~~	~~Approved District method~~	~~District approved averaging time~~	~~Outlet of the SCR~~

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

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

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

~~For natural gas fired turbines only, volatile organic compound (VOC) compliance shall be demonstrated as follows: a) stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.~~

~~The use of this alternative method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The results shall be reported with two significant digits.~~

~~The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emission limit.~~

~~[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 475]~~

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

~~**AQ-20** The project owner shall install and maintain a continuous emissions monitoring system (CEMS) to measure the following parameters:~~

~~CO concentration in ppmv~~

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

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

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

~~CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9%-%O_2 d)][(Qg*HHV)/10E6], where~~

~~K = 7.267*10^{-8} (lbs/scf)/ppm~~

~~Cco = Average of 4 consecutive 15 min. average CO concentrations, ppm~~

~~Fd = 8710 dscf/MMBTU natural gas~~

~~%O_2, d= Hourly average % by volume O_2 dry, corresponding to Cco~~

~~Qg = Fuel gas usage during the hour, scf/hr~~

~~HHV = Gross high heating value of the fuel gas, BTU/scf~~

~~[Rule 1303 – BACT, Rule 1703-PSD]~~

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

~~**AQ-21** The project owner shall install and maintain a CEMS to measure the following parameters:~~

~~NOx concentration in ppmv~~

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

~~Rule 2012 provisional relative accuracy test audit (RATA) testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start up and the provisional certification date of the CEMS, the project owner shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).~~

~~[Rule 1703 – PSD, Rule 2005, Rule 2012]~~

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

~~**AQ-22**~~ ~~The project owner shall install this equipment according to the following requirements:~~

~~Construction shall commence within 12 months of the date of the permit to construct unless the permit is extended, but in no case should the start of construction exceed 18 months from the date of the permit to construct. Construction shall not be discontinued for a period of 18 months or more.~~

~~[Rule 205, 40 CFR Part 52]~~

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

~~**AQ-23**~~ ~~The project owner shall upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02 project.~~

~~[CEQA]~~

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

~~**AQ-24**~~ ~~The project owner shall install this equipment according to the following requirements:~~

~~Total commissioning hours shall not exceed 491 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 47 hours of operation for each turbine. Only one turbine shall undergo steam blows at any one time and at a load of no more than 50%. During steam blows, the other two turbines in the block shall not be fired. During all other commissioning activities outside of steam blows, a maximum of 2 turbines may be operated at any one time.~~

~~The project owner shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning.~~

~~The project owner shall provide SCAQMD with written notification of the initial startup date. Written records of commissioning start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.~~

~~[Rule 1303 – BACT, Rule 1303 – Offsets, Rule 1703 – PSD, Rule 2005]~~

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

~~**AQ-25**~~ ~~The project owner shall, upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~The project owner shall record the total net power generated in a calendar month in megawatt-hours.~~

~~The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:~~

~~GHG = 60.08 * FF~~

~~Where, GHG is the greenhouse gas emissions in tons of CO2 and FF is the monthly fuel usage in millions standard cubic feet.~~

~~The project owner shall calculate and record the GHG emissions in pounds per net megawatt-hour on a 12-month rolling average. The GHG emissions from this equipment shall not exceed 652,827 tons per year on a 12-month rolling average basis. The calendar annual average GHG emissions shall not exceed 1,053.7 lbs per net megawatt-hour (1,138.0 lbs per net megawatt hour inclusive of equipment degradation).~~

~~The project owner shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.~~

~~[Rule 1714]~~

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

~~**AQ-26** The project owner shall, upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~The project owner shall record the total gross power generated in a calendar month in megawatt-hours.~~

~~The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:~~

~~GHG = 60.08 * FF~~

~~Where, GHG is the greenhouse gas emissions in tons of CO2 and FF is the monthly fuel usage in millions standard cubic feet.~~

~~The project owner shall calculate and record the GHG emissions in pounds per gross megawatt-hours on a 12-month rolling average. The calendar annual average GHG emissions shall not exceed 1,000 lbs per gross megawatt-hour, or the applicable limit which is published in the final EPA rule.~~

~~The project owner shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.~~

~~[40 CFR60 Subpart KKKK]~~

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

~~**AQ-27** This equipment shall not be operated unless the facility holds 39,854 pounds of NOx RECLAIM Trading Credits (RTCs) in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 62,507 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.~~

~~[Rule 2005]~~

~~**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-28** This equipment shall not be operated unless the facility holds 2,694 pounds of SOx RECLAIM Trading Credits (RTCs) in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 3,798 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.~~

~~[Rule 2005]~~

~~**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-29** The project owner shall provide to the District a source test report in accordance with the following specifications:~~

- ~~Source test results shall be submitted to the District no later than 60 days after the source tests required under conditions **AQ-17**, **AQ-18**, and **AQ-19** are conducted.~~
- ~~Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid particulate matter (PM) emissions, if required to be tested, shall also be reported in terms of grains/dry standard cubic feet.~~
- ~~All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.~~

~~Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (cubic feet per hour), the flue gas temperature, and the generator power output (MW) under which the test was conducted.~~

~~[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]~~

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

~~**AQ-30** The project owner shall keep records in a manner approved by the District, for the following parameter(s) or item(s):~~

~~Commissioning hours and type of control and fuel use~~

~~Date, time, and duration of each start-up and shutdown, and the type of startup (cold, warm, or hot).~~

~~In addition to the requirements of a certified continuous emissions monitoring system (CEMS), natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification~~

~~Minute by minute data (NO_2 and O_2 concentration and fuel flow rate at a minimum) for each turbine start up~~

~~Monthly number of hours each turbine is operated with duct firing~~

~~Total annual power output in MWh~~

~~[Rule 1303(b)(2) - Offsets]~~

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

~~**DUCT BURNER**~~

~~**AQ-31** This equipment shall not be operated unless the facility holds 13,488 pounds of NOx RECLAIM Trading Credits (RTCs) in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 21,155 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.~~

~~[Rule 2005]~~

~~**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~**AQ-32** This equipment shall not be operated unless the facility holds 912 pounds of SOx RECLAIM Trading Credits (RTCs) in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 1,286 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.~~

~~[Rule 2005]~~

~~**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District as part of Quarterly Operation Reports (**AQ-SC8**).~~

~~**SCR**~~

~~**AQ-33** The 5 ppmv NH_3 emission limit is averaged over 60 minutes at 15% O_2, dry basis. The project owner shall calculate and continuously record the NH_3 slip concentration using the following:~~

~~NH_3 (ppmv) = [a-b*(c*1.2)/1E+06]*1E+06/b where,~~

~~a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)~~

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

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

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

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

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

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-34** The project owner shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.~~

~~The project owner shall also install and maintain a device to continuously record the parameter being measured.~~

~~The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.~~

~~The injected ammonia rate shall be maintained within 11.8 gal/min and 33 gal/min except during start ups and shutdowns~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~The project owner shall also install and maintain a device to continuously record the parameter being measured.~~

~~The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.~~

~~The exhaust temperature at the inlet of the selective catalytic reduction shall be maintained between 400-700 deg F except during start up and shutdowns~~

~~[Rule 1303(a)(1) – BACT]~~

~~**<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 install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the selective catalytic reduction catalyst bed in inches of water column.~~

~~The project owner shall also install and maintain a device to continuously record the parameter being measured.~~

~~The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.~~

~~The differential pressure shall be maintained between 1.5 " WC and 3.5 " WC.~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-37**~~ ~~For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.~~

~~Condition Number **AQ-34**~~

~~Condition Number **AQ-35**~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-38**~~ ~~For the purpose of the following condition numbers, continuous monitoring shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.~~

~~Condition Number: **AQ-36**~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~**AQ-39**~~ ~~The project owner shall upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-2 project.~~

~~[CEQA]~~

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

~~CO CATALYST~~

~~**AQ-40** The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the CO Catalyst.~~

~~The project owner shall also install and maintain a device to continuously record the parameter being measured.~~

~~The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.~~

~~[Rule 1303(a)(1) – BACT]~~

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

~~AMMONIA STORAGE TANK~~

~~**AQ-41** The project owner shall vent this equipment, during filling, only to the vessel from which it is being filled.~~

~~[Rule 1303(a)(1)-BACT]~~

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

~~**AQ-42** The project owner shall install and maintain a pressure relief valve set at 50 pounds per square inch gage (psig).~~

~~[Rule 1303(a)(1)-BACT]~~

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

~~**AQ-43** The project owner shall upon completion of the construction, operate and maintain this equipment according to the following specifications:~~

~~In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-2 project.~~

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

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ACRONYMS

AAQS	Ambient Air Quality Standard
AERMOD	AMS/EPA Regulatory Model
AFC	Application for Certification
APCO	Air Pollution Control Officer
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMD	Air Quality Management District
AQMP	Air Quality Management Plan
ARB	California Air Resources Board
BACT	Best Available Control Technology
Btu	British Thermal Unit
CAAQS	California Ambient Air Quality Standards
CCR	California Code of Regulations
CEC	California Energy Commission (or Energy Commission)
CEMS	Continuous Emission Monitoring System
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPM	(CEC) Compliance Project Manager
Degrees F	Degrees Fahrenheit
DSCFM	Dry Standard Cubic Feet per Minute
ERC	Emission Reduction Credit
FDOC	Final Determination of Compliance
FSA	Final Staff Assessment
GHG	Greenhouse Gas
gr/scf	Grains per Standard Cubic Foot (7,000 grains = 1 pound)
H_2S	Hydrogen Sulfide
HSC	Health and Safety Code
lb/mmscf	Pounds per Million Standard Cubic Feet
lbs	Pounds
LLC	Limited Liability Company
LORS	Laws, Ordinances, Regulations and Standards
MCR	Monthly Compliance Report
$\mu g/m^3$	microgram per cubic meter

mg/m^3	milligrams per cubic meter
MMBtu/hr	Million British Thermal Units per Hour
MW	Megawatts (1,000,000 Watts)
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen or Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
PDOC	Preliminary Determination of Compliance
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSA	Preliminary Staff Assessment
PSD	Prevention of Significant Deterioration
PTA	Petition to Amend
PTC	Permit to Construct
PTE	Potential to Emit
PTO	Permit to Operate
PVMRM	Plume Volume Molar Ratio Method
RECLAIM	Regional Clean Air Incentives Market
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
scf	standard cubic feet
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_4	Sulfate
SOx	Oxides of Sulfur
SCAB	South Coast Air Basin
SWPPP	Storm Water Pollution Prevention Plan
tpy	tons per year

U.S. EPA	United States Environmental Protection Agency
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compounds

AIR QUALITY APPENDIX AIR-1
GREENHOUSE GAS EMISSIONS

Testimony of Wenjun Qian, Ph.D., P.E and David Vidaver

SUMMARY AND CONCLUSIONS

The Amended Huntington Beach Energy Project (Amended HBEP) project is a proposed addition to the state's electricity system. It would be an efficient, new, dispatchable natural gas-fired combined-cycle and simple-cycle power plant that would provide fast start capabilities but would produce greenhouse gas (GHG) emissions while generating electricity for California consumers. Its addition to the system would displace other less efficient, higher GHG-emitting generation and facilitate the integration of renewable resources. Because the project would improve the efficiency of existing system resources, the addition of Amended HBEP would contribute to a reduction of the California GHG emissions and GHG emission rate average. The relative efficiency of the Amended HBEP project and the system build-out of renewable resources in California would result in a net cumulative reduction of GHG emissions from new and existing fossil sources of electricity.

Electricity is produced by operation of an inter-connected system of generation sources. Operation of one power plant, like the Amended HBEP, affects all other power plants in the interconnected system. While the Amended HBEP burns natural gas for fuel and thus produces GHG emissions that contribute cumulatively to climate change, it would have a beneficial impact on system operation and facilitate a reduction in GHG emissions in several ways:

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

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[1] The entity responsible for balancing a region's electrical load and generation will "dispatch" or call on the operation of generation facilities. The "dispatch order" is generally dictated by the facility's electricity production cost, efficiency, location or contractual obligations.

[2] Fuel-use closely correlates to the efficiency of and carbon dioxide (CO_2) emissions from natural gas-fired power plants. And since CO_2 emissions from fuel combustion dominate greenhouse gas (GHG) emissions from power plants, the terms CO_2 and GHG are used interchangeably in this section.

- The Amended HBEP would replace capacity and generation mostly provided by aging, high GHG emitting power plants, some of which that are likely to retire in order to comply with the State Water Resource Control Board's (SWRCB) policy on the use of once through cooling (OTC).
- The Amended HBEP would replace less efficient generation in the South Coast local reliability area required to meet local reliability needs, reducing the GHG emissions associated with providing local reliability services and facilitating the retirement of aging, high GHG-emitting resources in the area.
- The combined-cycle portion of the Amended HBEP would have a higher thermal efficiency than the approved combined-cycle turbines of the licensed HBEP. The simple-cycle turbines proposed for the Amended HBEP would be less efficient than the approved combined-cycle turbines, but they can provide additional flexibility to support the intermittent/variable renewable generation[3].

Staff notes that mandatory reporting of GHG emissions per federal government and Air Resources Board greenhouse gas regulations would occur, and these reports would enable these agencies to gather the information needed to regulate the Amended HBEP in trading markets, such as those that are expected to be required by regulations implementing the California Global Warming Solutions Act of 2006 (AB 32). The Amended HBEP may be subject to additional reporting requirements and GHG reduction and trading requirements as these regulations are more fully developed and implemented.

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

The Amended HBEP is subject to the Greenhouse Gases Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.). The Amended HBEP would meet the standard of 0.5 metric tonnes CO_2 per megawatt-hour ($MTCO_2$/MWh) with a rating of 0.381 $MTCO_2$/MWh, which would be less than the rating of 0.479 $MTCO_2$/MWh for the licensed HBEP (CEC 2014bb).

[3] Variable and intermittent are often used interchangeably, but variable more accurately reflects the integration issues of renewables into the California grid. Winds can slow across a wind farm or cloud cover can shade portions of a solar field, temporarily reducing unit or facility output, but not shut down the unit or facility.

The GE 7FA.05 combined-cycle turbines are also expected to comply with the federal Standards of Performance for Greenhouse Gas Emissions (or Clean Air Act section 111[b]) of 1,000 pounds of carbon dioxide per gross megawatt hour (lb CO_2/MWh, gross) or (1,030 lb CO_2/ MWh, net) for base load natural gas fueled turbines. The GE LMS-100PB simple-cycle turbines are expected to comply with the limit of 120 lb CO_2 per million Btus (MMBtu) of natural gas heat input for non-base load natural gas fueled turbines. Should the combined-cycle turbines operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. Conditions of Certification **AQ-15** and **AQ-61** would ensure compliance with the new standards.

Staff has reached the following conclusions about the Amended HBEP based on CEQA guidelines:

- The Amended HBEP would have less than significant GHG emissions impacts because:
  - The combined-cycle portion of the Amended HBEP would have lower heat rate and lower GHG emissions than the units utilizing OTC that currently provide a share of the local reliability needs for the local capacity area (LCA). It would also be dispatched in lieu of less efficient, higher-emitting combined cycles when providing local reliability services.
  - The proposed simple-cycle turbines of the Amended HBEP would have lower heat rates and lower GHG emissions than those of the existing peaking facilities in the LCA.
  - The Amended HBEP would facilitate the integration of renewable energy resources that would lower the state-wide GHG emissions from the electricity sector.
- The Amended HBEP would have less than significant impacts by complying with applicable regulations and plans related to the reduction of GHG emissions as follows:
  - The Amended HBEP would be subject to compliance with the AB 32 Cap and Trade regulation that implements the state’s regulatory plan for reducing GHG emissions from the electricity sector;
  - The construction emissions mitigation measures that staff recommends to address criteria pollutant emissions would further minimize GHG emissions. The use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of future ARB regulations to reduce GHG from construction vehicles and equipment; and

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

AIR QUALITY GHG ANALYSIS

Testimony of Wenjun Qian, Ph.D., P.E.

INTRODUCTION

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

Federal rules that became effective December 29, 2009 (40 CFR 98) require federal reporting of GHGs. As federal rulemaking evolves, staff at this time focuses on analyzing the ability of the project to comply with existing federal- and state-level policies and programs for GHGs. The state has demonstrated a clear willingness to address global climate change though research, adaptation,[4] and GHG inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

Generation of electricity using any fossil fuel, including natural gas, can produce greenhouse gases along with the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts (CAA). For fossil fuel-fired power plants, the GHG emissions include primarily CO_2, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2 which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment, and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused or recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials[5].

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

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

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[4] 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).

[5] Global warming potential is a relative measure, compared to carbon dioxide, of a compound's residence time in the atmosphere and ability to warm the planet. Mass emissions of GHGs are converted into carbon dioxide equivalent (CO_2E) for ease of comparison.

After the approval of the HBEP, U.S. EPA published new source performance standards (NSPS) for greenhouse gas emissions for new, modified, and reconstructed fossil fuel-fired electric utility generating units on October 23, 2015. The Amended HBEP turbines would be subject to these new requirements.

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

Applicable LORS	Description	Complies?	Basis of Compliance
Federal			
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule "tailors" GHG emissions to PSD and Title V permitting applicability criteria. However, see discussions below.	Yes	See more discussions below.
40 Code of Federal Regulations (CFR) Parts 51 and 52	A new stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) is also considered to be a major stationary source subject to PSD requirements. As of June 23, 2014 the US Supreme Court has invalidated this requirement as a sole PSD permitting trigger. However, for permits issued on or after July 1, 2011 PSD applies to GHGs if the source is otherwise subject to PSD (for another regulated NSR pollutant) and the source has a GHG potential to emit (PTE) equal to or greater than 75,000 TPY CO_2E. The Amended HBEP is subject to the GHG PSD analysis.	Yes	See more discussions in the compliance with SCAQMD Rule 1714 below.
40 Code of Federal Regulations (CFR) Parts 60, 70, 71 and 98	On October 23, 2015, U.S. EPA published new source performance standards (NSPS) for greenhouse gas emissions for new, modified, and reconstructed fossil fuel-fired electric utility generating units. The Amended HBEP turbines would be subject to these requirements.	Yes	See more details in the **COMPLIANCE WITH GHG LORS** section below.
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.	Yes	See more details in the **COMPLIANCE WITH GHG LORS** section below.
State			
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards to reduce GHG emission to 1990 levels by 2020. Electricity production facilities are included. A cap-and-trade program became active in January 2012, with enforcement beginning in January 2013. Cap-and-trade is expected to achieve approximately 20 percent of the GHG reductions expected under AB 32 by 2020.	Yes	See more details in the **COMPLIANCE WITH GHG LORS** section below.

Applicable LORS	Description	Complies?	Basis of Compliance
SB 32 (Health and Safety Code Section 38566)	This legislation requires California to reduce GHG emissions to 40 percent below the statewide greenhouse gas emissions limit by the end of 2030.	Yes	See more details in the **COMPLIANCE WITH GHG LORS** section below.
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.)	Yes	See more details in the **COMPLIANCE WITH GHG LORS** section below.
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).	Yes	See more details in the **COMPLIANCE WITH GHG LORS** section below.
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.	Yes	See more details in the **COMPLIANCE WITH GHG LORS** section below.

COMPLIANCE WITH GHG LORS

Federal

The FDOC (SCAQMD 2016g) shows that the proposed combined-cycle turbines and simple-cycle turbines of the Amended HBEP would comply with the new NSPS for greenhouse gas emissions for new fossil fuel-fired electric utility generating units. The FDOC shows that the emission rate of the proposed combined-cycle unit would be 967.6 lbs CO_2 per MWh (net), assuming 8 percent performance degradation, which is less than the allowable 1,030 lbs CO_2/MWh (net). The GE LMS-100PB simple-cycle turbines are expected to have capacity factors less than their lower heating value efficiency and thus would be required to emit no more than 120 lb CO_2 per million Btus of heat input. Each GE LMS-100PB turbine is estimated to emit 117 lb CO_2 per MMBtu, which rounds to 120 lb CO_2 per MMBtu at two digits of precision. Should the combined-cycle turbines operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. Conditions of Certification **AQ-15** and **AQ-61** would ensure compliance with the new standards. See more details in the section below.

The Amended HBEP would be subject to federal mandatory reporting of GHG emissions.

State

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

On September 8, 2016, Senate Bill 32 (SB 32) was adopted. It extends California's commitment to reduce GHG emissions by requiring the state to reduce GHG emissions to 40 percent below the statewide greenhouse gas emissions limit by the end of 2030. H&SC §38550 defines the statewide GHG emission limit to be equivalent to 1990 emissions.

The Amended HBEP would emit at 0.381 $MTCO_2$/MWh, which complies with California's SB1368 Emissions Performance Standard (EPS) limit of 1,100 lb CO_2/MWh (0.5 MT/MWh).

Local

SCAQMD Rule 1714 establishes preconstruction review requirements for GHGs and the Amended HBEP is evaluated for these requirements in the FDOC. The Amended HBEP would be a major PSD source. The SCAQMD performed a PSD BACT analysis for GHGs and concluded thermal efficiency is the only technically and economically feasible alternative for CO_2/GHG emissions control for the Amended HBEP. The current design proposed for the Amended HBEP meets the BACT requirement for GHG emission reductions. The FDOC states that modeling analysis, monitoring for GHGs, and impact analysis from GHGs in the nearby Class I areas are not required for GHG PSD analysis.

GHG ANALYSIS

California is actively pursuing policies to reduce GHG emissions that include adding low-GHG emitting renewable electricity generation resources to the system. GHG emissions are not included in the class of pollutants traditionally called “criteria pollutants.” Since the impact of the GHG emissions from a power plant’s operation has global rather than local effects, those impacts should be assessed not only by analysis of the plant’s emissions, but also in the context of the operation of the entire electricity system of which the plant is an integrated part. Furthermore, the impact of the GHG emissions from a power plant’s operation should be analyzed in the context of applicable GHG laws and policies, especially Assembly Bill (AB) 32, California’s Global Warming Solutions Act of 2006.

GLOBAL CLIMATE CHANGE AND CALIFORNIA

Each of the first six months of 2016 set a record as the warmest respective month globally in the modern temperature record, which dates to 1880, according to scientists at NASA's Goddard Institute for Space Studies (GISS) in New York. The six-month period from January to June was also the planet's warmest half-year on record, with an average temperature 1.3 degrees Celsius (2.4 degrees Fahrenheit) warmer than the late nineteenth century (NASA/Goddard 2016). October 2016 was the second warmest October in 136 years of modern record-keeping, according to a monthly analysis of global temperatures by scientists at NASA's Goddard Institute for Space Studies (GISS) in New York[6]. According to “The Future Is Now: An Update on Climate Change Science Impacts and Response Options for California,” an Energy Commission document, the American West is heating up faster than other regions of the United States (CEC 2009c). The California Climate Change Center (CCCC) reports that, by the end of this century, average global surface temperatures could rise by 4.7°F to 10.5°F due to increased GHG emissions.

The accumulation of GHGs in the atmosphere regulates the earth’s temperature. Without these natural GHGs, the earth’s surface would be approximately 61°F (34°C) cooler (CalEPA 2006); however, emissions from fossil fuel combustion for activities such as electricity production and vehicular transportation have elevated the concentration of GHGs in the atmosphere above natural levels. ARB estimated that the mobile source sector accounted for approximately 37 percent of the GHG emissions generated in California from 2009 through 2012, while the electricity generating sector accounted for approximately 20 to 22 percent of the 2009 to 2012 California GHG emissions inventory, with just more than half of that on average from in-state generation sources (ARB 2014).

[6] http://data.giss.nasa.gov/gistemp/news/20161115/

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

Recent data collected at Mauna Loa, Hawaii indicate that atmospheric CO_2 concentration now exceed 400 ppm all year, and new research suggests that values will remain above this level (Betts et al 2016). According to the latest information available from the Intergovernmental Panel on Climate Change in their document "Climate Change 2014" (IPCC 2014), atmospheric CO_2 concentrations of 430 to 480 ppm would be expected to cause an approximate 2.7 degree Fahrenheit (F) temperature increase and CO_2 concentrations ranging from 580 ppm to 650 ppm are expected to cause an approximate 3.6 F temperature increase.

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).

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

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

On October 23, 2015, the U.S. EPA published a final rule (U.S. EPA 2015) under Clean Air Act section 111(b) that would limit greenhouse gas emissions (specifically, CO_2) from new, base load natural gas fueled turbines built after January 8, 2014 (for facilities with new turbines) and June 18, 2014 (for facilities with reconstructed turbines) to 1,000 lb CO_2 per MWh, gross (or 1,030 lb CO_2 per MWh, net), expressed at three digits of precision. The rule would also apply to non-base load natural gas-fueled turbines by limiting CO_2 emissions to 120 lb CO_2 per million Btus of natural gas heat input, expressed at two digits of precision.

According to the U.S. EPA final rule (U.S. EPA 2015), a "base load" natural gas-fired turbine is defined as one that has a capacity factor in percentage above the lower heating value efficiency of the turbine, expressed as a percentage. Correspondingly, a "non-base load" natural gas-fired turbine is one that has a capacity factor less than or equal to the lower heating value efficiency of the turbine, expressed as a percentage, with the value capped at 50 percent. Compliance is determined over a 12-month rolling average using a continuous emissions monitoring system or by measuring actual fuel use, including start-up, shut-down and periods of malfunction.

Also on October 23, 2015, the U.S. EPA published a final rule under Clean Air Act section 111(d) that principally applies to existing electricity generators but may also apply to new natural gas-fired turbines. This requirement may be triggered if the state chooses to meet the 111(d) requirements under a mass-based option and chooses to include both existing and new units in its plan, rather than implementing a rate-based option. States have until 2016 (with optional extensions to 2018) to choose which option to use for section 111(d), so the applicability of this requirement cannot be determined for the Amended HBEP at this time. However, the Amended HBEP would be required to participate in the AB 32 cap-and-trade program, which imposes compliance obligations for its greenhouse gas emissions, and would likely help to ensure that the facility complies with potentially applicable section 111(d) requirements. On February 9, 2016, the Supreme Court stayed implementation of the so-called "Clean Power Plan" pending judicial review.

The state has demonstrated a clear willingness to address global climate change (GCC) through research, adaptation, and GHG emission reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation (see the section **The Impact of the Amended HBEP on GHG Emissions from the State's Electricity Sector** below), and describes the applicable GHG policies and programs.

It is likely that GHG reductions mandated by AB 32, the Global Warming Solutions Act of 2006, which is being implemented 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). It is possible that percentage reductions in GHG emissions from the electricity sector will be higher than those from other sectors of the state's economy as decarbonizing the electricity sector may prove to be among the least-cost pathways to overall reductions. The Draft 2030 Target Scoping Plan calls for the electricity sector to reduce GHG emissions by 67 to 73 percent from 1990 levels by 2030 (ARB 2016).

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

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

On May 22, 2014, the ARB released its first update to their AB 32 Scoping Plan. On April 29, 2015, Governor Brown issued Executive Order B-30-15, directing state agencies to implement measures to reduce GHG emissions 40 percent below their 1990 levels by 2030 and to achieve the previously-stated goal of an 80 percent GHG reduction by 2050. In response, ARB is again updating the AB 32 Scoping Plan. If this project is built after 2020, the GHG regulatory landscape could be different than today.

On June 17, 2016, ARB released a concept paper addressing four options for updating the Scoping Plan that focus on extending AB 32 requirements beyond the year 2020. There are four alternatives listed in the concept paper, described as Concepts 1 to 4. These are summarized as follows:

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[7] Public Utilities Code § 8340 et seq.

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

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

1. Extending cap-and-trade and other complementary programs,
2. Expand complementary programs without extending cap-and-trade,
3. Aggressively expand transportation-related programs and other complementary programs without extending cap and trade, and
4. Replace cap-and-trade with a carbon tax and expanded complementary programs.

Staff's GHG analysis assumes the cap-and-trade provisions of AB 32 would continue as envisioned in Concept 1. If a carbon tax replaces cap-and-trade as envisioned in Concept 4, the effect on the Amended HBEP is expected to be approximately the same, depending on how the carbon tax is levied. However, if the cap-and-trade approach is abandoned as in Concepts 2 and 3, the only programmatic approach currently in place would apply to reducing GHG emissions from power plants would be the federal New Source Performance Standard requirements being developed by the U.S. EPA. As currently proposed, the Amended HBEP would comply with these federal GHG requirements. ARB has initiated a process to obtain public input on which of these options to pursue. ARB has held multiple public workshops on the Scoping Plan and the latest public workshop was held on November 7, 2016. They plan to present the final Scoping Plan to the Board in spring 2017.

SB 32 codifies H&SC §38566. This legislation was approved by the California Legislature on August 24, 2016 and signed by Governor Brown on September 8, 2016. The legislation requires California to reduce GHG emissions to 40 percent below the statewide greenhouse gas emissions limit by the end of 2030. H&SC §38550 defines the statewide GHG emission limit to be equivalent to 1990 emissions.

The FDOC shows that the emission rate of the proposed combined-cycle unit would be 967.6 lbs CO_2 per MWh (net), assuming 8 percent performance degradation (SCAQMD 2016g), which is less than the allowable 1,030 lbs CO_2/MWh (net). The GE LMS-100PB simple-cycle turbines are expected to have capacity factors less than their lower heating value efficiency and thus would be required to emit no more than 120 lb CO_2 per million Btus of heat input. Each GE LMS-100PB turbine is estimated to emit 117 lb CO_2 per MMBtu, which rounds to 120 lb CO_2 per MMBtu at two digits of precision. Should the combined-cycle turbines operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. Conditions of Certification **AQ-15** and **AQ-61** would ensure compliance with the new standards.

ELECTRICITY AND GREENHOUSE GAS EMISSIONS

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

GHG EMISSIONS FROM AMENDED HBEP

Construction of the Amended HBEP

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in temporary, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. Construction of the Amended HBEP project would involve 120 months of activity. The project owner provided annual GHG emission estimate for the construction phase. The GHG emissions estimate is presented below in **Greenhouse Gas Table 2**. The term CO_2E represents the total GHG emissions after weighting by the appropriate global warming potential.

Greenhouse Gas Table 2 also shows the maximum annual construction GHG emissions approved for the licensed HBEP. Except for the CH_4 emissions, the maximum annual construction GHG emissions estimated for the Amended HBEP would be higher than those approved for the licensed HBEP because of higher offsite emissions estimated from offsite delivery and material hauling trucks.

Greenhouse Gas Table 2
Estimated Maximum Annual Construction Greenhouse Gas Emissions

Source	CO_2	CH_4	N_2O	CO_2E
Amended HBEP				
Construction Total (Metric Tons/year)	8,289	0.13	0.063	8,311
Licensed HBEP				
Construction Total (Metric Tons/year)	2,938	0.14	0.06	2,960

Source: HBEP 2015a, CEC 2014bb

[10] See CEC 2009d, page 95.

Operations of the Amended HBEP

The primary sources of GHG during operation of the Amended HBEP would be the natural gas fired combustion turbines and the auxiliary boiler. The employee and delivery traffic GHG emissions from off-site activities are negligible in comparison with the gas turbine GHG emissions.

Greenhouse Gas Table 3 shows estimated GHG emissions for the Amended HBEP on an annual basis assuming the facility would operate at maximum permitted emissions levels. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials.

The project owner expects the gross plant capacity factor of the Amended HBEP (including the combined-cycle and simple-cycle turbines) to be above 60 percent (HBEP 2015a). Therefore, the Amended HBEP would be subject to SB 1368 Greenhouse Gas Emission Performance Standard of 0.500 $MTCO_2$/MWh. The estimated annual GHG performance would be approximately 0.381 $MTCO_2$/MWh, which would meet the Emission Performance Standard of 0.500 $MTCO_2$/MWh, averaged over all the turbines.

Greenhouse Gas Table 3 also shows the approved GHG emissions for the licensed HBEP for comparison purposes. The Amended HBEP would produce more energy with less GHG emissions compared to the licensed HBEP. The estimated annual GHG performance (0.381 $MTCO_2$/MWh) of the Amended HBEP would be better (lower $MTCO_2$/MWh) than that estimated for the licensed HBEP (0.479 $MTCO_2$/MWh).

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

Emissions Source	Operational GHG Emissions ($MTCO_2E$/yr)[a]
Amended HBEP	
Carbon Dioxide (CO_2)	1,782,131
Methane (CH_4)	840
Nitrous Oxide (N_2O)	1,001
Sulfur Hexafluoride (SF_6) Leakage	65.2
Total Project GHG Emissions ($MTCO_2E$/yr)	**1,784,036**
Estimated Annual Energy Output (MWh/yr)[b]	4,676,327
Estimated Annualized GHG Performance ($MTCO_2$/MWh)	**0.381**
Licensed HBEP	
Total Project GHG Emissions ($MTCO_2$/yr)	1,997,634
Estimated Annual Energy Output (MWh/yr)	4,170,821
Estimated Annualized GHG Performance ($MTCO_2$/MWh)	0.479

Source: CEC 2014bb, HBEP 2016n, SCAQMD 2016g, and independent staff analysis
Notes: [a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] Annualized basis uses the project owner's assumed maximum permitted operating basis.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

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

METHOD AND THRESHOLDS FOR DETERMINING SIGNIFICANCE

The CEQA guidelines provide three factors for lead agencies to consider when assessing the significance of impacts for the analysis of GHG emissions impacts (CEQA Guidelines, tit. 14, §15064.4).

- *The extent to which the project may increase or reduce greenhouse gas emissions as compared to the existing environmental setting;*
- *Whether the project emissions exceed a threshold of significance that the lead agency determines applies to the project; and*
- *The extent to which the project complies with regulations or requirements adopted to implement a statewide, regional, or local plan for the reduction or mitigation of greenhouse gas emissions. Such requirements must be adopted by the relevant public agency through a public review process and must reduce or mitigate the project's incremental contribution of greenhouse gas emissions. If there is substantial evidence that the possible effects of a particular project are still cumulatively considerable notwithstanding compliance with the adopted regulations or requirements, an EIR must be prepared for the project.*

Staff evaluates the emissions of the project in the context of the electricity sector as a whole and the AB 32 Scoping Plan implementation efforts for the sector, including the cap and trade regulation that constitutes the state's primary mechanism for reducing GHG emissions from the electricity sector. The Energy Commission's assessment approach does not include a specific numeric threshold of significance for GHG emissions; rather the assessment is completed in the context of how the project will affect the electricity sector's emissions based on its proposed role and its compliance with applicable regulations and policies.

Included in this sector-wide GHG emission analysis method is the determination of whether a project is consistent with the Avenal precedent decision, which requires a finding as a conclusion of law that any new natural gas-fired power plant certified by the Energy Commission "must:

- not increase the overall system heat rate for natural gas plants;
- not interfere with generation from existing renewables or with the integration of new renewable generation; and

- taking into account the two preceding factors, reduce system-wide GHG emissions."[11]

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

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts" (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.

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

PROPOSED CONDITIONS OF CERTIFICATION

Conditions of Certification **AQ-3**, **AQ-15**, **AQ-56**, **AQ-58**, and **AQ-61** in the Air Quality section relate to the greenhouse gas emissions from project operation are proposed. The facility owner would participate in California's GHG cap-and-trade program, and is required to report GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions, by purchasing allowances from the capped market and offsets from outside the AB 32 program. Similarly, the Amended HBEP would be subject to federal mandatory reporting of GHG emissions. The facility owner may have to provide additional reports and GHG reductions, depending on the future regulations formulated by the U.S. EPA or the ARB.

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

Testimony of David Vidaver

SUMMARY

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

STAFF'S FINDINGS REGARDING THE IMPACT OF THE HBEP ON GHG EMISSIONS

The Energy Commission previously found that the HBEP would unambiguously reduce GHG emissions from the state's electricity sector (CEC 2014bb). The GHG emissions produced by a new natural gas-fired generator are not incremental to the system, but are offset by reduced emissions from generators whose output is displaced by that of the new generator. New gas-fired generators do not displace hydroelectric or nuclear generation, technologies whose variable operating costs are lower. Nor do they displace output from renewable generators, who have not only lower variable operating costs, but often have must-take contracts for their output as well, and whose energy, in aggregate, must be procured in quantities sufficient to meet the state's Renewable Portfolio Standard. The output from new natural gas-fired generators instead displaces that from less-efficient existing natural gas-fired generators, whose variable costs are higher because they combust more natural gas per unit of electricity generated, and thus produce more GHG emissions. Under some circumstances the displaced output will be that from coal-fired generators, whose GHG emissions are even higher per MWh than those from natural gas-fired generators, as they are less thermally efficient and use a fuel with a higher carbon content per Btu.

IMPACT OF THE PROPOSED AMENDMENT TO THE HBEP ON GHG EMISSIONS

It follows from the previous section that development of the Amended HBEP would reduce GHG emissions from the electricity sector compared to the alternative of developing neither the project as previously approved or as now proposed.

It is not possible to determine – with any accuracy – the GHG emissions that would be expected from an electricity system that includes the licensed HBEP with one that includes the Amended HBEP. While the maximum amount of natural gas that can be combusted annually under the projects' air quality and other permits provides a ceiling for the plants' CO_2-equivalent emissions, permitted levels of operation and expected operation, while related, are very different metrics.[12] More importantly, the ceiling is for GHG emissions *from the plant itself*; its consideration ignores the quantity of GHG emissions from the generators that are displaced.

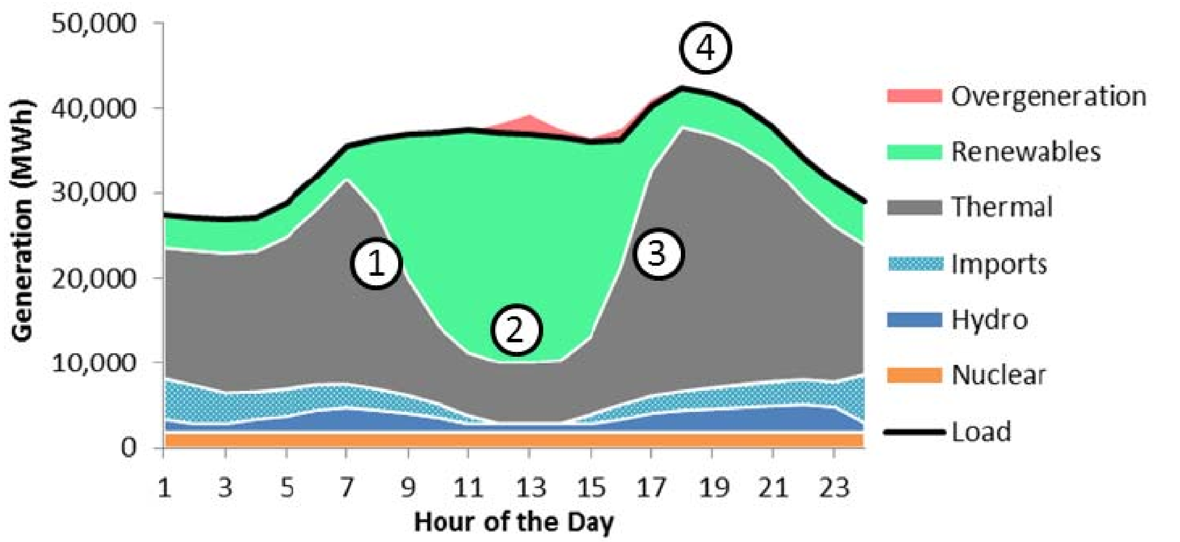
Similarly, a comparison of the thermal efficiencies of the two projects (e.g., at full load) does not provide any information regarding their expected GHG emissions or the system-wide emissions that would result from their development. While the combined-cycle portion of the proposed project has a higher thermal efficiency than the approved project at most levels of output, the differences in the efficiency and operating flexibility of the two projects mean that they would be operated differently. As such, they would displace different existing generation resources, whose thermal efficiencies, and thus GHG emissions, cannot be known a priori. As a result, their relative impact on system GHG emissions cannot be known with certainty. Similarly, while the LMS 100s now proposed are less efficient than the approved combined cycles, they are also more flexible, able to start up faster, cycle on and off multiple times per day, turn down to lower levels of output, etc. Again, they would be dispatched differently than a combined cycle, and thus displace different existing gas-fired resources.

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

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

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

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



Source: CA ISO 2014

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

A long-term solution for over-generation is expected to be the development of cost-effective, multi-hour storage, allowing the surplus to be stored until it can be used in evening hours. In the interim, however, over-generation can only be dealt with by curtailing renewable generation or reducing the amount of gas-fired generation that is needed during midday and early afternoon hours. The latter is facilitated by developing gas-fired resources that operate at low levels of output or cycle off during mid-day hours.[13]

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

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ACRONYMS

AB	Assembly Bill
ARB	California Air Resources Board
CAA	Clean Air Act
CalEPA	California Environmental Protection Agency
CA ISO	California Independent System Operator
CCCC	California Climate Change Center
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2E	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
EIR	Environmental Impact Report
EPS	Emission Performance Standard
FDOC	Final Determination of Compliance
FSA	Final Staff Assessment
GCC	Global Climate Change
GHG	Greenhouse Gas
GWh	Gigawatt-hour
GWP	Global Warming Potential
HBEP	Huntington Beach Energy Project
HFC	Hydrofluorocarbons
HSC	Health and Safety Code
IEPR	Integrated Energy Policy Report
IPCC	Intergovernmental Panel on Climate Change
LCA	Local Capacity Area
LTPP	Long-term Procurement Planning
MT	Metric tones
$MTCO_2E$	Metric Tons of CO_2-Equivalent
MW	Megawatts
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide

NOx	Oxides of Nitrogen or Nitrogen Oxides
NSPS	New Source Performance Standard
OTC	Once-Through Cooling
PFC	Perfluorocarbons
PSA	Preliminary Staff Assessment
PSD	Prevention of Significant Deterioration
RPS	Renewables Portfolio Standard
SB	Senate Bill
SF_6	Sulfur hexafluoride
SWRCB	State Water Resource Control Board
U.S. EPA	United States Environmental Protection Agency
WCI	Western Climate Initiative

PUBLIC HEALTH

Testimony of 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 as proposed in the petition to amend (PTA) the Final Decision for Huntington Beach Energy Project (HBEP, 12-AFC-02). Staff concludes that there would be no significant health impacts from the HBEP's potential toxic air contaminant (TAC) emissions. Staff also concludes that the proposed modification would not affect the HBEP's ability to comply with applicable health laws, ordinances, regulations, and standards (LORS).

The proposed modifications include changing the turbine technology in one combined-cycle power block from three Mitsubishi Heavy Industries 501DA turbines in a three-on-one configuration with a nominal capacity of 469 megawatts (MW) to two GE 7FA.05 turbines in a two-on-one configuration with a nominal capacity of 644 MW net with an auxiliary boiler. The other power block would be changed from three Mitsubishi Heavy Industries 501DA turbines in a combined-cycle configuration, with a nominal capacity of 469 MW to two GE LMS-100PB simple-cycle turbines with a nominal combined capacity of 200 MW.

In accordance with the California Environmental Quality Act (CEQA) Guidelines section 15162 (Cal. Code Regs., tit. 14, § 15162), staff concludes that no supplementation to the Energy Commission Final Decision is necessary for Public Health. The proposed project modifications constitute a considerable change in facts and circumstances from the 2014 Decision and it was necessary to evaluate the proposed project's incremental impacts on Public Health. There are no new significant environmental effects, nor is there a substantial increase in the severity of previously identified significant effects regarding public health impacts.

INTRODUCTION

On June 27, 2012, AES Southland, LLC, submitted an Application for Certification (AFC) for the HBEP. On October 29, 2014, the Energy Commission approved the AFC for HBEP with a Final Decision. On September 14, 2015, AES Southland, LLC, submitted to the Energy Commission a PTA the Final Decision for HBEP (12-AFC-02).

The project modifications proposed by this PTA related to Public Health include (HBEP 2015a, Section 1.2 and Section 2.0, HBEP 2016n, Section 5.1.1):

- The Amended HBEP would be constructed on 30 acres entirely within the site of the existing Huntington Beach Generating Station (HBGS) in Huntington Beach, California.

- The combustion turbine combined-cycle (CTCC) power block (Block 1) would include two General Electric (GE) Frame 7FA.05 combustion turbine generators (CTG) with unfired heat recovery steam generators (HRSGs), one steam turbine generator, an air-cooled condenser, a natural-gas-fired auxiliary boiler, and related ancillary equipment, with nominal summer capacity of 644 megawatts (MWs) net.
- The simple-cycle power block (Block 2) would include two GE LMS-100 simple-cycle combustion turbine generators, with a nominal capacity of 200 MWs net.
- Construction of the Amended HBEP CTCC units (Block 1) would require the demolition of the existing Huntington Beach Generating Station HBGS Unit 5, two former fuel oil tanks and associated fuel oil pipelines and containment berms. Demolition of Unit 5 is scheduled to occur in 2016 under the already approved Final Decision. Construction of Block 1 is expected to take approximately 35 months (including commissioning), with construction scheduled to occur from the second quarter of 2017 through the second quarter of 2020.
- Construction of the Amended HBEP simple-cycle CTG units (Block 2) would require the retirement and demolition of existing HBGS Units 3 and 4. Demolition of existing HBGS Units 3 and 4 is not part of the Amended HBEP project description.
- In addition to the construction of the new generating units, upon the commercial operation of the Amended HBEP simple-cycle power block, existing HBGS Units 1 and 2 would be decommissioned and demolished to their turbine deck. HBGS Unit 1 would be retired in the fourth quarter of 2019 to provide interconnection capacity for the new CTCC units. HBGS Unit 2 would be retired either after commercial operation of the HBEP simple-cycle CTG or at the final compliance deadline for once-through-cooling intake structures.

The purpose of this Final Staff Assessment (FSA) is to determine if emissions of TACs from the Amended HBEP would have the potential to cause significant adverse public health impacts or to violate standards for the protection of public health. If potentially significant health impacts are identified, staff would identify and recommend mitigation measures necessary to reduce such impacts to insignificant levels.

In addition to the analysis contained in this Public Health section that focuses on potential effects to the public from emissions of TACs, Energy Commission staff address the potential impacts of regulated, or criteria, air pollutants in the Air Quality section of this FSA, and assess the health impacts on public and workers from accidental releases of hazardous materials in the Hazardous Materials Management and Worker Safety and Fire Protection sections. The health and nuisance effects from electric and magnetic fields are discussed in the Transmission Line Safety and Nuisance section. Pollutants released from the project's wastewater streams are discussed in the Soil and Surface Water and Water Supply sections. Releases in the form of hazardous and nonhazardous wastes are described in the Waste Management section.

SUMMARY OF THE DECISION

The Energy Commission made the following findings for HBEP (CEC 2014bb):

1. Demolition, construction, and operation of the project will result in the routine release of criteria and noncriteria pollutants that have the potential to adversely impact public health.

2. Emissions of criteria pollutants, as discussed in the Air Quality section of the Decision, will be mitigated to levels consistent with applicable state and federal standards.

3. Emissions of noncriteria pollutants, or toxic air contaminants, are assessed according to procedures developed by state and federal regulatory agencies to evaluate potential health effects to protect the most sensitive individuals in the population.

4. The accepted method used by state and federal regulatory agencies in assessing the significance for both acute and chronic non-carcinogenic public health effects of noncriteria pollutants is known as the hazard index method. A similar method is used for assessing the significance of potential carcinogenic effects based on incremental exposure levels.

5. The evidence contains a screening level health risk assessment of the project's potential health effects due to emissions of TACs.

6. The health risk assessment is based on worst case assumptions using the highest emission factors, assuming the worst weather conditions, and calculating effects at the point of maximum impact, so that actual risks are expected to be much lower at any other location.

7. Exposure to diesel particulate emissions from construction equipment will not result in long-term carcinogenic or non-carcinogenic health effects with the implementation of the conditions of certification set forth in the Air Quality section of the Decision.

8. Exposure to demolition and construction-related diesel particulates will be mitigated to the extent feasible by implementing measures to reduce equipment emissions.

9. Exposure to particulates in fugitive dust due to demolition, excavation, and construction activities will be mitigated to insignificant levels by implementing measures to reduce dust production and dispersal.

10. The health risk assessment for exposure to TAC emissions during project operations confirmed that acute and chronic calculated risks fall below the significance level of 1.0, and that the cancer risk is below the significance level of 10 in one million.

11. Cumulative impacts from noncriteria pollutants were analyzed in accordance with CEQA requirements and are not expected to be significant.

12. Since the project's contributions to health risks are well below the significance level, the project is not expected to contribute significantly to a cumulative health impact.

13. Members of the public potentially exposed to toxic air contaminant emissions of this project—including sensitive receptors such as the elderly, infants, and people with pre-existing medical conditions—will not experience any acute or chronic significant health risk or any significant cancer risk as a result of that exposure.

14. Environmental justice populations will not be adversely affected by the construction and operation of the project.

The Commission made the following conclusions, and proposed no conditions of certification:

1. Emissions of noncriteria pollutants from the construction and operation of the HBEP do not pose a significant direct, indirect, or cumulative adverse public health risk.

2. The project will comply with the applicable LORS specified herein.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

No LORS applicable to the project have changed since the Commission Decision was published in October 2014. This section evaluates compliance with these requirements and summarizes the applicable LORS.

Public Health Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Federal	
Clean Air Act section 112 (Title 42, U.S. Code section 7412)	Section 112 of the Clean Air Act addresses emissions of hazardous air pollutants (HAPs). This act requires new sources that emit more than 10 tons per year of any specified HAP or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology (MACT).
40 Code of Federal Regulations (CFR) Part 63 Subpart YYYY (National Emission Standard for Hazardous Air Pollutants for Stationary Combustion Turbines)	This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility with emissions of 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit.
40 Code of Federal Regulations (CFR) Part 68 (Risk Management Plan)	This rule requires facilities storing or handling significant amounts of acutely hazardous materials to prepare and submit Risk Management Plans.
State	
California Health and Safety Code section 25249.5 et seq. (Proposition 65)	These sections establish thresholds of exposure to carcinogenic substances above which Proposition 65 exposure warnings are required.
California Health and Safety Code, Article 2, Chapter 6.95, Sections 25531 to 25541; California Code of Regulations (CCR) Title 19 (Public Safety), Division 2 (Office of Emergency Services), Chapter 4.5 (California Accidental Release Prevention Program)	These regulations require facilities storing or handling significant amounts of acutely hazardous materials to prepare and submit Risk Management Plans.

Applicable LORS	Description
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 the California Air Resources Board (ARB) / OEHHA (Office of Environmental Health Hazard Assessment) guidelines, toxic contaminants do not exceed acceptable levels.
California Public Resource Code section 25523(a); Title 20 California Code of Regulations (CCR) section 1752.5, 2300–2309 and Division 2 Chapter 5, Article 1, Appendix B, Part (1); California Clean Air Act, Health and Safety Code section 39650, et seq.	These laws and regulations require a quantitative health risk assessment for new or modified sources, including power plants that emit one or more TACs.
Local	
South Coast Air Quality Management District (SCAQMD) Rule 1401 (New Source Review of Toxic Air Contaminants)	This rule specifies limits for maximum individual cancer risk (MICR), cancer burden, and noncancer acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permit units which emit TACs.
SCAQMD Rule 1403 (Asbestos Emissions from Demolition/Renovation Activities)	This rule specifies work practice requirements to limit asbestos emissions from building demolition and renovation activities, including the removal and associated disturbance of asbestos-containing materials.
SCAQMD Rule 212(c)(3) (Permits – Public Notice)	This rule requires public notification if the MICR, based on Rule 1401, exceeds one in 1 million (1×10^{-6}), due to a project's proposed construction, modification, or relocation for facilities with more than one permitted source unless the applicant can show the total facility-wide MICR is below 10 in 1 million (10×10^{-6}).

ENVIRONMENTAL IMPACT ANALYSIS

Characteristics of the natural environment, such as meteorology and terrain, affect the project's potential for impacts on public health. An emission plume from a facility would affect elevated areas before lower terrain areas because of reduced opportunity for atmospheric mixing. Consequently, areas of elevated terrain located near a project site can often be subjected to increased pollutant impacts compared to lower-level areas. Also, the land use around a project site can influence impacts due to population distribution and density, which, in turn, can affect public exposure to project emissions. Additional factors affecting potential public health impacts include existing air quality and environmental site contamination.

SETTING

The Amended HBEP site is located in the city of Huntington Beach at 21730 Newland Street, just north of the intersection of the Pacific Coast Highway (Highway 1) and Newland Street, within the SCAQMD. Huntington Beach is a seaside city in Orange County in Southern California. The project is proposed to be located on the site of the existing Huntington Beach Generating Station HBGS, an operating power plant. The HBEP site is bounded on the west by a manufactured home/recreational vehicle park, on the north by a tank farm, on the north and east by the Huntington Beach Channel and residential areas, on the southeast by the Huntington Beach Wetland Preserve/Magnolia Marsh wetlands, and to the south and southwest by the Huntington Beach State Park and the Pacific Ocean. The site is located on a gently sloping coastal plain (HBEP 2012a, section 5.9). The setting has not changed from the setting of the previously approved project.

The licensed HBEP was proposed as a 939-MW power plant consisting of two independently operating, three-on-one combined-cycle combustion turbine power blocks. Each power block would have consisted of three natural gas-fired CTGs, three supplemental-fired HRSGs, one steam turbine generator (STG), an air-cooled condenser, and related ancillary equipment (HBEP 2015a, Section 1.1). The Amended HBEP differs from the Licensed HBEP in key ways. The Amended HBEP is proposed as an 844-MW (net), natural gas fired power plant with a combined-cycle unit with an air-cooled condenser and two simple-cycle units, to be located on the site of the existing Huntington Beach Generating Station in Huntington Beach, California.

Sensitive receptors, such as infants, the aged, and people with specific illnesses or diseases, are the subpopulations which are more sensitive to the effects of toxic substance exposure. According to the PTA, approximately 353,173 residents live within a 6-mile radius of the site proposed for HBEP, and the sensitive receptors within a 6-mile radius of the project site include (HBEP 2015a, section 5.9.2):

- 275 preschool/daycare centers
- 12 nursing homes
- 81 schools
- 579 hospitals, clinics, and/or pharmacies
- 7 colleges

The nearest sensitive receptor is a daycare facility located 0.3 mile east of the project site. The nearest school is Edison High School, located approximately 0.5 mile to the northeast of the project site. The nearest residence is located approximately 250 feet west-northwest of the facility along Newland Street. The nearest businesses are located along Edison Drive, just north of the project site (HBEP 2015a, section 5.9.2). As discussed above, the changes in source-receptor relationship due to the changed facility design requires a new analysis which is presented in a later portion of this section.

METEOROLOGY AND CLIMATE

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into the air and the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants along with the associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced, and localized exposures may be increased.

Atmospheric stability is one characteristic related to turbulence, or the ability of the atmosphere to disperse pollutants from convective air movement. Mixing heights (the height marking the region within which the air is well mixed below the height) are lower during mornings because of temperature inversions. These heights increase during warm afternoons. Staff's Air Quality section presents a more detailed description of meteorological data for the area.

The climate of the South Coast Air Basin is mild, tempered by cool sea breezes. The area's climatic conditions are strongly influenced by its terrain and geographical location. The basin is a coastal plain with connecting broad valleys and low hills, bounded by the Pacific Ocean in the southwest quadrant with high mountains forming the remainder of the perimeter. The general region lies in the semi-permanent high pressure zone of the eastern Pacific. This usually mild climatological pattern is interrupted infrequently by periods of extremely hot weather, winter storms, or Santa Ana winds (HBEP 2012a, section 5.1.3.2).

The annual and quarterly wind rose plots (from 2010 to 2014) for the National Weather Service John Wayne Airport meteorological station[1] show that the prevailing winds that blow to the Amended HBEP site were mostly from the southwest. Only a small percent of prevailing winds blowing to the Amended HBEP site were from other directions (HBEP 2015a, Section 5.1.5.2 and Appendix 5.1C). The metrological data used for this analysis covered the years from 2010 to 2014 while the Licensed HBEP used observations made during earlier years (from 2008 to 2012). Please refer to the **Air Quality** section for more details.

[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.

EXISTING PUBLIC HEALTH CONCERNS

By examining average toxic concentration levels from representative air monitoring sites, together with cancer risk factors specific to each carcinogenic contaminant, a lifetime cancer risk can be calculated to provide a background risk level for inhalation of ambient air.

This analysis is prepared in order to identify the most current status of respiratory diseases (including asthma), cancer, and childhood mortality rates in the population located within the same county or air basin of the amended project site. Such assessment of existing health concerns provides staff with a basis on which to evaluate the significance of any additional health impacts from the Amended HBEP and assess the need for further mitigation. The public health information below is the most current available and is updated from the previous analysis.

Cancer

When examining such risk estimates, staff considers it important to note that the overall lifetime risk of developing cancer for the average male in the United States is about 1 in 2, or 500,000 in 1 million and about 1 in 3, or 333,333 in 1 million for the average female (American Cancer Society 2014).

From 2008 to 2012, the cancer incidence rates in California were 48.56 in 1 million for males and 39.48 for females. Also, from 2008 to 2012, the cancer death rates for California are 18.34 in 1 million for males and 13.53 in 1 million for females (American Cancer Society, Cancer Facts & Figures 2016, Table 4 and Table 5). The trend is toward lower values compared to earlier results for the 2007 to 2011 period.

By examining the State Cancer Profiles presented by the National Cancer Institute, staff found that cancer death rates in Orange County have been falling between 2008 and 2012. These rates (of 14.63 per 1,000,000, combined male/female) were somewhat lower than the statewide average of 15.51 per 1,000,000 (National Cancer Institute 2013).

According to the County Health Status Profiles 2015, the death rate due to all cancers, from 2011-2013, is 14.51 in 1 million for Orange County, slightly lower than the cancer death rate (15.09 in 1 million) for California (CDPH 2015).

Lung Cancer

As for lung and bronchus cancers, from 2008 to 2012 the cancer incidence rates in California were 5.58 in 1 million for males and 4.21 in 1 million for females. Also, from 2008 to 2012 the cancer death rates for California were 4.37 in 1 million for males and 3.05 in 1 million for females (American Cancer Society, Cancer Facts & Figures 2016, Table 4 and Table 5). The trend is toward lower values compared to earlier results for the 2007 to 2011 period.

According to the County Health Status Profiles 2015, the death rate due to lung cancers (not including bronchus cancer), from 2011-2013, is 3.16 in 1 million for Orange County, slightly lower than the cancer death rate (3.36 in 1 million) for California (CDPH 2015).

Asthma

The asthma diagnosis rates in Orange County are lower than the average rates in California for both adults (age 18 and over) and children (ages 1-17). The percentage of adults in Orange County diagnosed with asthma was reported as 6.0 percent in 2005-2007, compared to 7.7 percent for the general California population. Rates for children for the same 2005-2007 period were reported as 9.5 percent in Orange County compared to 10.1 percent for the state in general (Wolstein et al., 2010).

Air Toxics Emission Estimates

As a follow-up to the Multiple Air Toxics Exposure Study II and III (MATES II and III), SCAQMD commenced a fourth MATES study (MATES IV) in 2012. After the approval of the previous project, the final report of MATES IV was published in May 1, 2015. The results of MATES IV study show a continuing downward trend in TACs. The comparison of county-wide population-weighted risk in Table 4-5 in the final report of MATES IV shows TAC reductions that occurred in Orange County, with values decreasing from 781 parts per million in 2005 to 315 per million in 2012. South Coast Air Basin (SCAB) data follow the same trend, with corresponding TACs decreasing from 853 per million in 2005 to 367 per million in 2012 (MATES IV, 2015).

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff conducts its public health analysis by evaluating the information and data provided in the PTA by the project owner. Staff also relies upon the expertise and guidelines of the California Environmental Protection Agency (Cal/EPA) Office of Environmental Health Hazard Assessment (OEHHA) in order to identify: (1) contaminants that cause cancer or other noncancer health effects, and (2) the toxicity, cancer potency factors and non-cancer RELs of these contaminants. Staff relies upon the expertise of the ARB and the local air districts to conduct ambient air monitoring of TACs and on the California Department of Public Health to evaluate pollutant impacts in specific communities. It is not within the purview or the expertise of the Energy Commission staff to duplicate the expertise and statutory responsibility of these agencies. The HRA process addresses three categories of health impacts: (1) acute (short-term) health effects, (2) chronic (long-term) noncancer effects, and (3) cancer risk (also long-term). This approach is consistent with the previous analysis. However, OEHHA's Air Toxics Hot Spots Program Guidance Manual for the Preparation of Risk Assessments (Guidance Manual) was updated March 6th, 2015 (OEHHA 2015). Also, a newer computer program, the Hot Spots Analysis and Reporting Program 2 (HARP2), has been developed by ARB as a tool to implement the risk assessments as outlined in this guidance manual (ARB 2016a).

Acute Noncancer Health Effects

Acute health effects are those that result from short-term (one-hour) exposure to relatively high concentrations of pollutants. Such effects are temporary in nature and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic Noncancer Health Effects

Chronic noncancer health effects are those that result from long-term exposure to lower concentrations of pollutants. Long-term exposure has been defined as more than 12 percent of a lifetime, or about 8 years (OEHHA 2003, p. 6-5). Chronic noncancer health effects include diseases such as reduced lung function and heart disease.

Reference Exposure Levels (RELs)

The analysis for both acute and chronic noncancer health effects compares the maximum project contaminant levels to safe levels known as Reference Exposure Levels, or RELs. These are amounts of toxic substances to which even sensitive individuals could be exposed without suffering any adverse health effects (OEHHA 2003, p. 6-2). These exposure levels are specifically designed to protect the most sensitive individuals in the population, such as infants, the aged, and people with specific illnesses or diseases which make them more sensitive to the effects of toxic substance exposure. The RELs are based on the most sensitive adverse health effect reported in the medical and toxicological literature and include specific margins of safety. The margins of safety account for uncertainties associated with inconclusive scientific and technical information available at the time of setting the REL. They are therefore meant to provide a reasonable degree of protection against hazards that research has not yet identified.

Concurrent exposure to multiple toxic substances would result in health effects that are equal to, less than, or greater than effects resulting from exposure to the individual chemicals. Only a small fraction of the thousands of potential combinations of chemicals have been tested for the health effects of combined exposures. In conformity with California Air Pollution Control Officers Association guidelines, the HRA assumes that the effects of each substance are additive for a given organ system (OEHHA 2003, pp. 1-5, 8-12). Other possible mechanisms due to multiple exposures include those cases where the actions would be synergistic or antagonistic (where the effects are greater or less than the sum, respectively). For these types of exposures, the health risk assessment could underestimate or overestimate the risks.

Cancer Risks

For carcinogenic substances, the health assessment considers the risk of developing cancer and assumes that continuous exposure to the carcinogen would occur over a 70-year lifetime[2]. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound estimate based on the worst-case assumptions.

[2] In 2015 Guidance, OEHHA recommends that an exposure duration (residency time) of 30 years be used to estimate individual cancer risk for the maximally exposed individual resident (MEIR). In addition, for the maximally exposed individual worker (MEIW), OEHHA now recommends using an exposure duration of 25 years to estimate individual cancer risk for off-site workers (OEHHA 2015, Table 8.5).

Cancer Potency Factors

Cancer risk is expressed in terms of the number of chances per million of developing cancer. It is a function of the maximum expected pollutant concentration, the probability that a particular pollutant would cause cancer (called a potency factor), and the length of the exposure period. Cancer risks for individual carcinogens are added together to yield a total cancer risk for each potential source. The conservative nature of the screening assumptions used means that the actual cancer risks from project emissions would be considerably lower than estimated.

As previously noted, the screening analysis is performed to assess the worst-case risks to public health associated with the amended project. If the screening analysis were to predict a risk below significance levels, no further analysis would be necessary and the source would be considered acceptable with regard to carcinogenic effects. If however, the risk were to be above the significance level, then further analysis using more realistic site-specific assumptions would be performed to obtain a more accurate estimate.

Significance Criteria

Energy Commission staff assesses the maximum cancer impacts from specific carcinogenic exposures by first estimating the potential impacts on the maximally exposed individual. This is a person hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using the worst-case assumptions. Since the individual’s exposure would produce the maximum impacts possible around the source, staff uses this risk estimate as a marker for acceptability of the project’s carcinogenic impacts. This approach is consistent with the previous analysis.

Acute and Chronic Noncancer Health Risks

Non-criteria pollutants are evaluated for short-term (acute) and long-term (chronic) non-cancer health effects, and the noted cancer impacts from long-term exposures. The significance of project-related impacts is determined separately for each of the three health effects categories. Staff assesses the noncancer health effects by calculating a hazard index. A hazard index is a ratio obtained by comparing exposure from facility emissions to the safe exposure level (i.e. REL) for that pollutant. A ratio of less than 1.0 suggests that the worst-case exposure would be below the limit for safe levels and would thus be insignificant with regard to health effects. The hazard indices for all toxic substances with the same type of health effect are added together to yield a Total Hazard Index for the source. The Total Hazard Index is calculated separately for acute effects and chronic effects. A Total Hazard Index of less than 1.0 would indicate that cumulative worst-case exposures would not lead to significant noncancer health effects. In such cases, noncancer health impacts from project emissions would be considered unlikely even for sensitive members of the population. Staff would therefore conclude that there would be no significant noncancer project-related public health impacts. This assessment approach is consistent with risk management guidelines of both the California OEHHA and the U.S. Environmental Protection Agency (EPA).

Cancer Risk

Staff relies upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986, (Health & Safety Code, §§25249.5 et seq.) for guidance in establishing significance levels for carcinogenic exposures. Title 22, California Code of Regulations section 12703(b) states that “the risk level which represents no significant risk shall be one which is calculated to result in one or less excess cancer cases within an exposed population of 100,000, assuming lifetime exposure.” This risk level is equivalent to a cancer risk of 10 in 1 million, which is also written as 10×10^{-6}. In other words, under state regulations, an incremental cancer risk greater than 10 in 1 million from a project should be regarded as suggesting a potentially significant carcinogenic impact on public health. The 10 in 1million risk level is also used by the Air Toxics “Hot Spots” (AB 2588) program as the public notification threshold for air toxic emissions from existing sources.

An important distinction between staff’s approach and the Proposition 65 risk characterization approach is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the total risk from all the cancer-causing pollutants to which the individual might be exposed in the given case. Thus, the manner in which the significance level is applied by staff is more conservative (health-protective) than the manner applied by Proposition 65. The significant risk level of 10 in 1 million is also consistent with the level of significance adopted by many California air districts. In general, these air districts would not approve a project with a cancer risk estimate more than 10 in 1 million.

As noted earlier, the initial risk analysis for a project is typically performed at a screening level, which is designed to overstate actual risks, so that health protection could be ensured. Staff’s analysis also addresses potential impacts on all segments of the population, including the young, the elderly, and people with existing medical conditions, that would render them more sensitive to the adverse effects of toxic air contaminants and any minority or low-income populations that are likely to be disproportionately affected by impacts. To accomplish this goal, staff uses the most current acceptable public health exposure levels (both acute and chronic) set to protect the public from the effects of air toxics being analyzed. When a screening analysis shows the cancer risks to be above the significance level, refined assumptions would be applied for likely a lower, more realistic risk estimate. If, after using refined assumptions, the project’s risk is still found to exceed the significance level of 10 in 1 million, staff would require appropriate measures to reduce the risk to less than significant levels. If, after all feasible risk reduction measures have been considered and a refined analysis still identifies a cancer risk of greater than 10 in 1 million, staff would deem such a risk to be significant and would not recommend project approval.

AMENDED PROJECT’S CONSTRUCTION/DEMOLITION IMPACTS AND MITIGATION MEASURES

The construction and demolition period for Amended HBEP would be approximately 10 years or 120 months (HBEP 2015a, Table 2.2-1), longer than the licensed HBEP (7.5 years). The potential construction/demolition risks are normally associated with exposure to asbestos, fugitive dust, and combustion emissions (i.e. diesel exhaust).

Asbestos

The demolition of buildings containing asbestos could cause the emission of asbestos particles. The mitigation measures needed to reduce the impacts of asbestos, asbestos containing materials (ACM), and other hazardous wastes, from the construction or demolition phases of the project are covered in the Waste Management section. As for asbestos, Condition of Certification **WASTE-2** requires that the project owner to submit the SCAQMD Asbestos Notification Form to SCAQMD and the Energy Commission for review and approval prior to removal and disposal of asbestos. This program ensures there will be no release of asbestos that could impact public health and safety. Please refer to staff's **Waste Management** section for detailed mitigation measures regarding the construction/demolition of asbestos and ACM, and information on the safe handling and disposal of these and all project-related wastes.

Fugitive Dust

Fugitive dust is defined as dust particles that are introduced into the air through certain activities such as soil cultivation, vehicles operating on open fields, or dirt roadways. Fugitive dust emissions during construction of the amended project could occur from:

- Dust entrained during site preparation and grading/excavation at the construction and demolition sites;
- Dust entrained during onsite movement of construction vehicles on unpaved surfaces; and
- Wind erosion of areas disturbed during construction activities.

The effects of fugitive dust on public health are covered in the Air Quality section, which includes staff's recommended mitigation measures, including **AQ-SC3** (Construction Fugitive Dust Control) and **AQ-SC4** (Dust Plume Response Requirement) to prevent fugitive dust plumes from leaving the project boundary. As long as the dust plumes are kept from leaving the project site, there will be no significant concern of fugitive dust adversely affecting public health.

Diesel Exhaust

Emissions of combustion byproducts during construction would result from:

- Exhaust from diesel construction equipment used for site preparation, grading, excavation, trenching, and construction of onsite and offsite (transmission- and gas pipeline-related) structures and from demolition activities;
- Exhaust from water trucks used to control construction/demolition dust emissions;
- Exhaust from portable welding machines, small generators, and compressors;
- Exhaust from diesel trucks used to transport workers and deliver concrete, fuel, and construction supplies to construction/demolition areas; and
- Exhaust from vehicles used by construction/demolition workers to commute to and from the project areas.

Construction Health Risk Assessment (HRA) for Diesel Exhaust

The primary air toxic pollutant of concern from construction/demolition activities is diesel particulate matter (DPM). A screening construction HRA for DPM was conducted by the project owner to assess the potential impacts associated with diesel emissions during the construction and demolition activities at HBEP. The construction HRA was performed for a shorter exposure duration and different receptor locations. The total DPM exhaust emissions were averaged over the demolition and construction period (i.e. 120 months) and spatially distributed in: (1) the site's eastern area, which is associated with the demolition of HBGS Unit 5, preparation of the former Plains All American tank farm area, and construction of the combined-cycle power block; (2) the site's western area, which is associated with construction of the simple-cycle power block; and (3) the site's southern area, which is associated with demolition of HBGS Units 1 and 2 (HBEP 2015a, Section 5.9.3.1).

The project owner did not run the HARP2 model to evaluate construction-related public health impacts, but rather took the maximum locations from DPM modeling and hand calculated the results. The maximum modeled annual average concentration of diesel particulate matter calculated by the project owner was 0.01027μg/m^3 (HBEP 2015a, Appendix 5.9B, Table 5.9B.3).

The demolition/construction HRA estimated the rolling cancer risks for each 10-year period during a 30-year exposure duration (starting with exposure during the third trimester of pregnancy) for residential exposure and a 10-year exposure duration (from age 16 to 25) for worker exposure, aligned with the expected construction duration, at the Point of Maximum Impact (PMI), Maximum Exposed Individual Resident (MEIR), Maximum Exposed Individual Worker (MEIW), and maximum exposed sensitive receptor. The excess cancer risks were estimated using the following (HBEP 2016n, Section 5.9.3.2):

- Equations 5.4.1.1 and 8.2.4A from the *Air Toxic Hot Spots Guidance Manual for Preparation of Health Risk Assessments* (OEHHA, 2015) for residential exposure.
- Equations 5.4.1.2A, 5.4.1.2B, and 8.2.4B from the *Air Toxic Hot Spots Guidance Manual for Preparation of Health Risk Assessments* (OEHHA, 2015) for worker exposure. Staff only evaluates the health impact on off-site workers because on-site workers are protected by Cal OSHA and are not required to be evaluated under the Hot Spots Program, unless the worker also lives on the facility site or property (OEHHA 2003, Chapter 8, pp. 8-5 and 8-6).
- The maximum annual ground-level concentrations used to estimate risk were determined through dispersion modeling with AERMOD.
- The AERMOD modeling approach for the HRA was consistent with that used for the criteria pollutant modeling analysis, except that the receptor grid for the HRA included census and sensitive receptors and excluded receptors located within the AES-controlled property.
- The demolition/construction emission estimates modeled are presented in Table 5.9-1 of PTA.

Chronic risks were also estimated for the PMI, MEIR, MEIW, and maximum exposed sensitive receptor, based on the same emission rates and ground-level concentrations described above. To calculate chronic risk, as characterized by a health index, the maximum annual ground-level concentration was divided by the DPM Reference Exposure Level of 5 micrograms per cubic meter (µg/m3) (OEHHA 2015).

Staff reviewed the project owner's analysis and the results are contained in **Public Health Table 2** (HBEP 2015a, Section 5.9.3.2, Table 5.9B.3, Table 5.9B.4, Table 5.9B.5 and Table 5.9B.6). Staff also included the results of the 2014 final staff assessment (FSA) for HBEP for comparison, shown as "2014 FSA for Licensed HBEP" in the table below (CEC 2014d). The results show the excess cancer risk at the PMI, MEIR, the highest value at a sensitive receptor, and MEIW are 5.22 in a million, 4.23 in a million, 0.48 in a million and 0.25 in a million, respectively, all less than the Energy Commission staff's significant impact threshold of 10 in a million. The predicted chronic health index at the PMI, MEIR, the highest value at a sensitive receptor, and MEIW are 0.0021, 0.0017, 0.00019, and 0.0021, respectively. The chronic hazard indices for diesel exhaust during construction/demolition activities are all lower than the significance level of 1.0. This means that there would be no chronic non-cancer impacts expected from construction/demolition activities (HBEP 2015a, Section 5.9.3.2). They all show lower values than the Licensed HBEP.

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

	Receptor Type	Risk Value		Significance Level	Significant?
		2014 FSA for Licensed HBEP	2015 PTA for Amended HBEP		
Derived Cancer Risk (per million)	PMI	12.3	5.22	10	No
	MEIR	3.5	4.23	10	No
	at a Sensitive Receptor	1.86	0.48	10	No
	MEIW	11	0.25	10	No
Chronic HI (dimensionless)	PMI	0.0461	0.0021	1	No
	MEIR	0.0131	0.0017	1	No
	MEIW	0.115	0.0021	1	No
	at a Sensitive Receptor	-	0.00019	1	No

Sources: HBEP 2015a, Section 5.9.3.2, Table 5.9B.3, Table 5.9B.4, Table 5.9B.5 and Table 5.9B.6 and CEC 2014d.

Based on the results of project owner's and staff's analyses, and considering the following two additional factors: (1) the potential exposure of DPM would be sporadic and limited in length and (2) the predicted incremental increase in cancer risk at the MEIR and MEIW and chronic health index at the PMI, MEIR, and MEIW are each less than the significance thresholds of 10 in one million and 1.0, respectively, staff concludes that impacts associated with the DPM from anticipated HBEP construction and demolition activities would be less than significant.

Conditions of Certification **AQ-SC5** (Diesel-Fueled Engine Control) and **AQ-SC6** in the Air Quality section would ensure that cancer-related impacts of diesel exhaust emissions for the public and off-site workers are mitigated during construction/ demolition activities to a point where they are not considered significant. The potential levels of criteria pollutants from operation of construction/demolition equipment are discussed in staff's Air Quality section along with mitigation measures and related conditions of certification. The pollutants of most concern in this regard are particulate matter (PM), carbon monoxide (CO), sulfur dioxide (SO_2), and nitrogen dioxide (NO_2).

AMENDED PROJECT'S OPERATIONAL IMPACTS AND MITIGATION MEASURES

Table 5.9-2 and Table 5.9-3 of the PTA (HBEP 2016n) list the specific non-criteria pollutants that would be emitted as combustion byproducts from the combustion turbines (i.e. two GE 7FA.05s and two LMS-100 PBs) and one auxiliary boiler. Air toxics emission factors for the combustion turbines and the auxiliary boiler were provided by SCAQMD, with the exception of ammonia. For combustion turbines, the ammonia emission factor was based on an operating exhaust ammonia limit of 5 parts per million by volume (ppmv) at 15 percent oxygen and an F-factor of 8,710 (Note: an F-factor is the ratio of the carbon dioxide generated by the combustion of a given fuel to the amount of heat produced.) For the auxiliary boiler, the ammonia emission factor was based on an operating exhaust ammonia limit of 5 ppmv at 3 percent oxygen and an F-factor of 8,710. Additionally, polycyclic aromatic hydrocarbons (PAH) emissions were conservatively assumed to be controlled up to 50 percent through the use of an oxidation catalyst (EPA, 2000), which is proposed for use with both the GE 7FA.05s and GE LMS-100PBs (HBEP 2016n, Section 5.9.3.1).

The health risk from exposure to each project-related pollutant is assessed using the "worst case" emission rates and impacts. Maximum hourly emissions are used to calculate acute (one-hour) noncancer health effects, while estimates of maximum emissions on an annual basis are used to calculate cancer and chronic (long-term) noncancer health effects.

<u>Hazard Identification</u>

Numerous health effects have been linked to exposure to TACs, including development of asthma, heart disease, Sudden Infant Death Syndrome (SIDS), respiratory infections in children, lung cancer, and breast cancer (OEHHA 2003). According to the HBEP PTA, the major toxic air contaminants emitted from the operation of the combustion turbines and auxiliary boiler include acetaldehyde, acrolein, ammonia, benzene, 1,3-buadine, ethylbenzene, formaldehyde, napthalene, polycyclic aromatics, propylene oxide, toluene and xylene. **Public Health Table 3** and **Public Health Table 4** list each such pollutant.

Public Health Table 3
The Main Pollutants Emitted from the Amended Project

Criteria Pollutants	Non-criteria Pollutants
Carbon monoxide (CO)	Acetaldehyde
Oxides of nitrogen (NO_x)	Acrolein
Particulate matter (PM10 and PM2.5)	Ammonia
Oxides of sulfur (SO_2)	Benzene
Volatile Organic Compounds (VOCs)	1,3-Butadiene
	Ethylbenzene
	Formaldehyde
	Naphthalene
	Polycyclic Aromatic Hydrocarbons (PAHs, as BaP[a])
	Propylene oxide
	Toluene
	Xylene

Source: HBEP 2016n, Table 5.9-2 and Table 5.9-3
[a] Benzo[a]pyrene

Public Health Table 4
Types of Health Impacts and Exposure Routes Attributed to Toxic Emissions

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

Source: OEHHA / ARB 2016b

Exposure Assessment

Public Health Table 4 shows the exposure routes of TACs and how they would contribute to the total risk obtained from the health risk analysis. The applicable exposure pathways for the toxic emissions include inhalation, home grown produce, dermal (through the skin) absorption, soil ingestion, and mother's milk. This method of assessing health effects is consistent with OEHHA's Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA 2015) referred to earlier.

The next step in the assessment process is to estimate the project's incremental concentrations using a screening air dispersion model and assuming conditions that would result in maximum impacts. The project owner used the EPA-recommended air dispersion model, AERMOD, along with 5 years (2010–2014) of compatible meteorological data from the John Wayne Airport meteorological station (HBEP 2015a, Section 5.1.5.2).

Dose-Response Assessment

Public Health Table 5 lists the toxicity values used to quantify the cancer and noncancer health risks from the project's combustion-related pollutants. It was modified from Table 5.9-2 and Table 5.9-3 of the PTA Revised Air Quality and Public Health Assessment Sections (HBEP 2015A, Section 5.1.5.2], excluding oral cancer potency factor and chronic oral REL. The listed toxicity values include RELs and the cancer potency factors published in the OEHHA's Guidelines (OEHHA 2015) and OEHHA/ARB Consolidation Table of OEHHA/ARB Approved Risk Assessment Health Values (ARB 2016b). RELs are used to calculate short-term and long-term noncancer health effects, while the cancer potency factors are used to calculate the lifetime risk of developing cancer.

Public Health Table 5
Toxicity Values Used to Characterize Health Risks

Toxic Air Contaminant	Inhalation Cancer Potency Factor $(mg/kg\text{-}d)^{-1}$	Chronic Inhalation REL $(\mu g/m^3)$	Acute Inhalation REL $(\mu g/m^3)$
Acetaldehyde	0.010	140	470 (1-hr) 300 (8-hr)
Acrolein	—	0.35	2.5 (1-hr) 0.7 (8-hr)
Ammonia	—	200	3,200
Benzene	0.10	60	1,300
1,3-Butadiene	0.60	20	—
Ethylbenzene	0.0087	2,000	—
Formaldehyde	0.021	9	55 (1-hr) 9 (8-hr)
Napthalene	0.12	9.0	—
Polycyclic Aromatic Hydrocarbons (PAHs, as BaP)	3.9	—	—
Propylene Oxide	0.013	3	3100
Toluene	—	300	37,000
Xylene	—	700	22,000

Sources: OEHHA/ARB 2016b

Characterization of Risks from TACs

As described above, the last step in a HRA is to integrate the health effects and public exposure information, provide quantitative estimates of health risks resulting from project emissions, and then characterize potential health risks by comparing worst-case exposure to safe standards based on known health effects.

The project owner's HRA was prepared using the ARB's HARP2. Emissions of non-criteria pollutants from the project were analyzed using emission factors, as noted previously, obtained mainly from the SCAQMD. Air dispersion modeling combined the emissions with site-specific terrain and meteorological conditions to analyze the worst-case short-term and long-term concentrations in air for use in the HRA. Ambient concentrations were used in conjunction with cancer unit risk factors and RELs to estimate the cancer and noncancer risks from operations. In the following sub-sections, staff reviews and summarizes the work of the project owner, and evaluates the adequacy of the project owner's analysis by conducting an independent HRA.

Staff evaluated the project owner's analysis, and the results are shown below in **Public Health Table 6**. Staff also included the results of the 2014 FSA for the Licensed HBEP for comparison (CEC 2014d). The analysis was conducted for the general population, sensitive receptors, nearby residences and the project's work force. The sensitive receptors, as previously noted, are subgroups that would be at greater risk from exposure to emitted pollutants, and include the very young, the elderly, and those with existing illnesses.

On March 6, 2015, OEHHA approved a revision to the Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments (OEHHA 2015). OEHHA developed age sensitivity factors to take into account the increased sensitivity to carcinogens during early-in-life exposure (OEHHA 2015, Table 8.3). This new methodology is used to reflect the fact that exposure varies among different age groups and exposure occurring in early life has a higher weighting factor.

Health risks potentially associated with ambient concentrations of carcinogenic pollutants were calculated in terms of excess lifetime cancer risks. The total cancer risk at any specific location is found by summing the contributions from the individual carcinogens. Health risks from non-cancer health effects were calculated in terms of hazard index as a ratio of ambient concentration of TACs to RELs for that pollutant.

The following is a summary of the most important elements of the health risk assessment for the Amended HBEP (HBEP 2016n, Section 5.9.3.2):

- The analysis was conducted using the latest version of ARB/OEHHA HARP2[3], which incorporates methodology presented in OEHHA's 2015 Guidance;
- Emissions are based upon concurrent operation of all four natural-gas-fired turbines and one auxiliary boiler. The existing fire pumps are already permitted by the SCAQMD and are considered part of the existing background conditions, so they were not included in the public health analysis for HBEP;
- Mandatory minimum pathways and homegrown pathways were selected to evaluate cancer risk and chronic hazard index at the PMI, MEIR, and sensitive receptor;
- Worker pathways (inhalation, dermal, and soil) were selected to evaluate cancer risk and chronic hazard index at the MEIW;

[3] HARP2 can be downloaded from ARB's HARP website. http://www.arb.ca.gov/toxics/harp/harp.htm

- The Risk Management Policy Derived method was used to calculate cancer risk at the PMI, MEIR, and sensitive receptor, consistent with SCAQMD guidance (SCAQMD, 2015); the OEHHA-Derived method was used for all remaining scenarios.

Cancer Risk at the Point of Maximum Impact

The most significant result of a HRA is the numerical cancer risk for the maximally exposed individual (MEI) which is the individual located at the PMI and risks to the MEIR. As previously noted, human health risks associated with emissions from the proposed project are unlikely to be higher at any other location than at the PMI. Therefore, if there is no significant impact associated with concentrations at the PMI location, it can be reasonably assumed that there would not be significant impacts in any other location in the project area. The cancer risk to the MEI at the PMI is referred to as the MICR. However, the PMI (and thus the MICR) is not necessarily associated with actual exposure because in many cases, the PMI is in an uninhabited area. Therefore, the MICR is generally higher than the maximum residential cancer risk. MICR is based on 24 hours per day, 365 days per year, 30 year lifetime exposure.

As shown below in **Public Health Table 6**, total worst-case individual cancer risk for the Amended HBEP was calculated by staff to be 4.26 in one million at the PMI. The PMI is approximately 0.15 miles northeast of the HBEP facility boundary. As **Public Health Table 6** shows, the cancer risk value at PMI is below the significance level, 10 in one million, indicating that no significant adverse cancer risk is expected.

Chronic and Acute Hazard Index (HI)

The screening HRA for the project included emissions from all sources and resulted in a maximum chronic Hazard Index (HI) of 0.011 and a maximum acute HI of 0.056 (HBEP 2016n, Table 5.9-4). As **Public Health Table 6** shows, both acute and chronic hazard indices are less than 1.0, indicating that no short- or long-term adverse health effects are expected.

Project-Related Impacts at Area Residences

Staff's specific interest in the risk to the maximally exposed individual in a residential setting is based on the MEIR (MEIR is used for this purpose because this risk most closely represents the maximum project-related lifetime cancer risk). Residential risk is presently assumed by the regulatory agencies to result from an exposure lasting 24 hours per day, 365 days per year, over a 30- year lifetime. Residential risks are presented in terms of MEIR and health hazard index (HHI) at residential receptors in **Public Health Table 6**. The cancer risk for the MEIR[4] is 2.68, which is below the significance level. The maximum resident chronic HI and acute HI are 0.0068 and 0.019, respectively (HBEP 2016n, Table 5.9-4). They are both less than 1.0, indicating that no short- or long-term adverse health effects are expected at these residences.

[4] The AFC states the nearest resident is approximately 250 feet west-northwest of the facility along Newland Street (HBEP 2012a, Section 5.9.1.1); however, the MEIR is not located at this position, but is located approximately 0.4 mile northeast of the HBEP boundary.

Risk to Workers

The cancer risk to potentially exposed workers was presented by the project owner in terms of risk to the maximally exposed individual worker or MEIW at PMI and is also summarized in **Public Health Table 6**. The project owner's assessment for potential workplace risks uses a shorter duration exposure rather than the 30-year exposure used for residential risks. Workplace risk is presently calculated by regulatory agencies using exposures of 8 hours per day, 245 days per year, over a 25- year period. As shown in **Public Health Table 6**, the cancer risk for workers at MEIW (i.e. 0.15 in 1 million) is below the significance level (HBEP 2016n, Table 5.9-4).

Risk to Sensitive Receptors

The highest cancer risk at a sensitive receptor is 1.49 in one million[5], the highest chronic HI is 0.0038 and the acute HI is 0.013. (HBEP 2016n, Table 5.9-4). All risks are below significance levels.

In **Public Health Table 6**, it is notable that the cancer and noncancerous risks from Amended HBEP operation would be below their respective significance levels. This means that no health impacts would occur within all segments of the surrounding population. Therefore, staff concludes there is no need for conditions of certification to protect public health.

Title 40 CFR Part 63 Subpart YYYY

The regulation applied to gas turbines located at major sources of HAP emissions is 40CFR Part 63 Subpart YYYY. A major source is defined as a facility with emissions of 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit.

The total combined potential HAP emissions from all the combined cycle turbines, simple cycle turbines, and auxiliary boiler are about 13 tpy, and the total formaldehyde emissions from all sources combined is about 6 tpy. No single HAP would be emitted at a rate of 10 tpy or more. Therefore, HBEP is classified as an area source of HAPs, and is not subject to this subpart (SCAQMD 2016j).

[5] This sensitive receptor is located approximately 0.6 mile northeast of HBEP boundary, not the nearest sensitive receptor.

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

Receptor Location	Cancer Risk (per million)		Chronic HI[f]		Acute HI[f]	
	2014 FSA for Licensed HBEP	2015 PTA for HBEP	2014 FSA for Licensed HBEP	2015 PTA for HBEP	2014 FSA for Licensed HBEP	2015 PTA for HBEP
PMI[a]	2.54[d]		0.00778	0.011	0.0781	0.056
	4.32[e]	4.26				
Residence MEIR[b]	2.2	2.68	0.00691	0.0068	0.0502	0.019
Worker MEIW[c]	0.446	0.15	0.00778	0.011	0.0781	0.056
Highest Cancer Risk at a Sensitive Receptor	1.65	1.49	0.00519	0.0038	0.0183	0.013
Significance level	10		1		1	

Source: HBEP 2016n, Table 5.9-4
[a] PMI = Point of Maximum Impact
[b] MEIR = MEI of residential receptors. Location of the residence of the highest risk with a 30-year residential scenario.
[c] MEIW = MEI for offsite workers. Occupational exposure patterns assuming standard work schedule, i.e. exposure of 8 hours/day, 5 days/week, 49 weeks/year for 25 years.
[d] Applicant's calculated value using previous OEHHA methodology.
[e] Cancer risk calculated by using the Age Sensitivity Factors recommended by OEHHA (OEHHA 2012).
[f] HI = Hazard Index

CUMULATIVE IMPACTS AND MITIGATION

A project would result in a significant adverse cumulative impact if its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (California Code of Regulations, Title 14, section 15130). As for cumulative impacts for cumulative hazards and health risks, if the implementation of the amended project, as well as the past, present, and probable future projects, would not cumulatively contribute to regional hazards, then it could be considered a less than cumulatively considerable impact.

The geographic scope of analysis for cumulative effects to public health is a six-mile buffer zone around the project site. This is the same six-mile buffer zone for localized significant cumulative air quality impacts described and evaluated in the Air Quality section. While MATES II and MATES III studies were discussed, cumulative impacts of the amended project along with other projects within a 6-mile radius were not quantitatively evaluated in the PTA (HBEP 2016n, section 5.9.4).

The maximum cancer risk and non-cancer hazard index (both acute and chronic) for operations emissions from the Amended HBEP estimated independently by the project owner, staff, and the SCAQMD (SCAQMD 2016b and SCAQMD 2016j) are all below the level of significance. While air quality cumulative impacts could occur with sources within a 6-mile radius, cumulative public health impacts are usually not significant unless the emitting sources are extremely close to each other, within a few blocks, not miles. Since no cumulative projects are within a few blocks of the HBEP, staff concludes that the Amended HBEP project, even when combined with these projects, would not contribute to cumulative impacts in the area of public health.

Moreover, as previously noted, the maximum impact location would be the spot where pollutant concentrations for the amended project would theoretically be highest. Even at this hypothetical location, staff does not expect any significant change in lifetime risk to any person, given the calculated incremental cancer risk of 4.26 in one million, which staff regards as not contributing significantly to the previously noted county-wide population-weighted risks of MATES VI, 315 per million for Orange County and 367 per million for SCAB. Modeled facility-related risks are much lower for more distant locations. Given the previously noted conservatism in the calculation method used, the actual risks would likely be much smaller. Therefore, staff does not consider the incremental risk estimate from Amended HBEP's operation as suggesting a potentially significant contribution to the area's overall or cumulative cancer risk that includes the respective risks from the background pollutants from all existing area sources.

COMPLIANCE WITH LORS

Staff has conducted a HRA for the Amended HBEP and found no potentially significant adverse impacts for any receptors, including sensitive receptors. In arriving at this conclusion, staff notes that its analysis complies with all directives and guidelines from the Cal/EPA Office of Environmental Health Hazard Assessment and the California Air Resources Board. Staff's assessment is biased towards protection of public health and takes into account the most sensitive individuals in the population. Using extremely conservative (health-protective) exposure and toxicity assumptions, staff's analysis demonstrates that members of the public potentially exposed to toxic air contaminant emissions from this project, including sensitive receptors such as the elderly, infants, and people with pre-existing medical conditions, would not experience any acute or chronic significant health risk or any significant cancer risk as a result of that exposure.

Staff incorporated every conservative assumption called for by state and federal agencies responsible for establishing methods for analyzing public health impacts. The results of that analysis indicate that there would be no direct or cumulatively significant public health impact on any population in the area. Therefore staff concludes that construction and operation of the HBEP and demolition of the HBGS would comply with all applicable LORS regarding long-term and short-term project impacts in the area of public health.

Additionally, staff reviewed **Socioeconomics Figure 1**, which shows that the environmental justice population (see the **Socioeconomics** and **Executive Summary** sections of this FSA for further discussion of environmental justice) is not greater than fifty percent within a six-mile buffer of the Amended HBEP site. Because no members of the public potentially exposed to toxic air contaminant emissions from this project would experience acute or chronic significant health risk or cancer risk, there would not be a public health impact resulting from construction and operation of the amended project to an environmental justice population or any other group of people.

RESPONSE TO PSA COMMENTS

PROJECT OWNER

Comment: *Preliminary Staff Assessment (PSA) page 4.7-13, Fugitive Dust: The third bullet indicates that fugitive dust could occur from an onsite concrete batch plant. However, the project will not have an onsite concrete batch plant (HBEP 2016cc).*

Response: Staff agrees to delete the third bullet.

PUBLIC

Comment from Mike M Trelles: *During the demolition, will any hazardous material or particulates get exposed to the air, with an almost constant breeze is there a potential of those dangers going air born? (PB 2016a)*

Response: Some of these materials would likely become airborne. However, according to the results of health risk assessment (HRA) for construction/demolition, due to the mitigation measures to be used, the magnitude of such releases is expected to be small enough that all risk numbers are below significance thresholds. Therefore, staff concludes that no significant adverse health impacts from toxic air emissions (TACs) are expected.

INTERVENORS

Staff received no comments from the interveners in the area of Public Health.

AGENCIES

Staff received no comments from the agencies in the area of Public Health.

CONCLUSIONS AND RECOMMENDATIONS

Staff has analyzed the potential public health risks associated with construction and operation of the Amended HBEP using a conservative methodology that accounts for impacts to the most sensitive individuals in a given population. Staff concludes that there would be no significant health impacts from the project’s toxic air emissions. According to the results of the HRA, both construction/demolition and operating emissions from the HBEP would not contribute significantly or cumulatively to morbidity or mortality in any age or ethnic group residing in the project area.

PROPOSED CONDITIONS OF CERTIFICATION

No public health conditions of certification are proposed for Amended HBEP.

REFERENCES

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

CEC 2014d - Final Staff Assessment (TN 202405). Submitted to CEC/ Docket Unit June 2, 2014.

HBEP 2012a - AES Southland Development, LLC / Stephen O'Kane (TN 66003). *Application for Certification (AFC), Volume I & II, dated, June 27, 2012*. Submitted to CEC/ Dockets on June 27, 2012.

HBEP 2012n - Stoel Rives LLP / Melissa A. Foster (TN 68366). *Applicant's Responses to Staff's Data Requests, Set 1A (#1-72), dated, November 2, 2012.* Submitted to CEC/ Dockets on November 2, 2012.

HBEP 2015a - Petition to Amend With Appendices (TN 206087). CEC/Docket Unit on September 9, 2015.

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HBEP 2016n - AES Southland Development, LLC/Stephen O'Kane (TN 210969). Petition to Amend (12-AFC-02C) Revised Air Quality and Public Health Assessment, dated April 6, 2016. Submitted to John Heiser/CEC/Docket Unit on April 6, 2016

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PB 2016a - Public/Mike M. Trelles (TN 212145). Health and Nuisance Cost, dated June 7, 2016. Submitted to CEC/Docket Unit on July 5, 2016

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OEHHA (Office of Environmental Health Hazard Assessment). 2015, Air Toxics Hot Spots Program Risk Assessment Guidelines. Guidance Manual for Preparation of Health Risk Assessments, March 6th, 2015.

Declarations

&

Resumes

DECLARATION OF
JOHN HEISER

I, John Heiser, declare as follows:

1. I am presently employed by the California Energy Commission in the Environmental Protection Office of the Siting, Transmission, and Environmental Protection Division as a Planner III.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on the Introduction and Executive Summary for the Huntington Beach Energy Project Amendment based on my independent analysis of the Petition to Amend and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 11/28/2016 Signed: John Heiser

At: Sacramento, California

Resume John Heiser, AICP

John Heiser
Planner III – Project Manager

EDUCATION

B.A. in Geography, Rural and Small Town Planning, 1990, Chico State University, Chico, CA

M.A. in City and Regional Planning, 2000, Cal Poly, San Luis Obispo, CA

AREAS OF SPECIALIZATION

Program/Project Management
Renewable Energy Development
Environmental Compliance
Resource Management

John Heiser has experience in the areas of Energy Facility Siting, Municipal Planning and Private Planning Development. Mr. Heiser's skills include project planning management, conducting feasibility studies, economic development, land use and environmental analysis, agency management, plan implementation, policy analysis, grant programs and capital improvement districts. John's planning disciplinary experience includes sustainable energy planning, airport planning, traffic program and transportation planning, housing element updates, zoning ordinance and general plan updates, working with tenant lease agreements with City owned properties, and contract administration.

EMPLOYMENT SUMMARY

2012 to Date: California Energy Commission, Planner III – Energy Facility Siting

2011-2012: Hauge Brueck Associates, LLC. Planner

2009-2011: Tulare County Resource Management Agency, Planner III

2008-2009: City of Wasco, Community Development Director

2008-2009: JSE Planning Consultants, Owner

2007-2008: City of Isleton, Community Development Director

2006-2008: Willdan, Senior Planner

2005-2006: El Dorado County Community Development, Senior Planner

2004-2005: El Dorado County Department of Transportation, Senior Planner

2001-2004: City of Marina Planning Department, Associate Planner

2000-2001: Santa Barbara County Community Development, Planner III

1998: El Dorado County Community Development, Contract Planner

1992-1997: Modoc County Planning Department, Planner II

1991-1992: Harland Bartholomew and Associates, Planning Intern

1988-1988: QUAD Consultants, Planning Intern

EMPLOYMENT

2012 to Date: California Energy Commission, Planner III, Energy Facility Siting – Project Manager. Plan, organize, direct and manage the State regulatory process for electric generating plants from application through issuance of permit. Plan, organize and direct the efforts of 23 disciplinary environmental and engineering staff in actions related to the California Environmental Quality Act (CEQA) requirements. Recommend actions, policies and procedures affecting the project and commission program direction. Conduct public workshops and hearings related to proposed projects. I Compile, edit, and issue staff environmental assessments and other CEQA related documents.

2011-2012: Hauge Brueck Associates, LLC. Associate. Mr. Heiser managed planning and environmental projects related to renewable energy development and other jurisdictional land use entitlement requests. John managed 15 utility scale solar photovoltaic (PV) energy facilities in Tulare County ranging from 20 to 50 Mega Watts in size. Nine of the fifteen solar PV projects have been approved by Tulare County. John was instrumental in creating an entitlement process in Tulare County for these facilities located on agricultural lands and agricultural lands subject to Williamson Act Contracts. This process has assisted other County and City Jurisdictions in California with renewable energy facility sitting issues and entitlement procedures. This entitlement process was recently recognized by the Central Section California Chapter American Planning Association by awarding Tulare County first place for this effort. John was the program manager for Vestal Almond, Vestal Herder and Vestal Fireman Solar PV utility scale projects in Tulare County.

2009-2011: Tulare County. Planner III. Mr. Heiser was engaged in both project review and countywide planning divisions by either providing support to RMA staff and or project managing land use entitlements that require CEQA determination. Prepared CEQA documents, prepare and present staff reports to the Agricultural Advisory Committee, Site Plan Review Committee, Planning Commission and Board of Supervisors. Assisted with county wide planning division on surface mining activities, Williamson Act Contracted lands, County Dairy Team and lead planner on large scale projects. Developed and implemented RMA staff policies and procedures for sitting renewable energy facilities located on agricultural and Williamson Act Contracted lands. John was the project manager for the Tule River Indian Tribe 1 million gallon waste water treatment plant for the Indian reservation. John provided support in the County's updated housing element and General Plan update as well as the Yokohl Ranch development. John was the lead contact person for renewable energy development information for Tulare County, project manage fifteen large scale solar PV facilities located on agricultural lands including project managing the consultants preparing the CEQA documentation for these projects.

2008 – 2009: JSE Consultants: Folsom, CA. Principal-Owner. Owner and Principal of JSE – Consulting Firm located in Folsom, California. JSE was a group of planning, engineering, and building consultants that have vast experience in every level of development, consulting and agency management. They were engaged members of our communities and have held positions as company owners, private builders and developers, and public work directors. The primary purpose of providing Community Development Services was to offer staffing support, assist jurisdictional (City/County) staff in addressing planning and design issues; process area/community/specific plans, and any other plans as directed by the jurisdiction. Provided environmental documentation services; assist the jurisdiction to identify overall community goals, growth and policies. These services included current and long range planning, development project processing, Environmental compliance and process analysis. As an additional service we offered LEED ND Certification and were familiar with the objectives and credits, as defined by the Green Building Council. It is JSE's mission to incorporate sustainability into its projects.

2006 – 2008: Willdan. Senior Planner. Mr. Heiser provided staff augmentation services for local public planning agencies including acting Community Director for the City of Isleton, California. As Community Development Director for Isleton, duties included but not limited to updating the City's housing element, the City's 5-year redevelopment plan and coordinate efforts with Sacramento LAFCO regarding several annexation proposals in Isleton. Additional efforts included working on three subdivision projects requiring annexation and EIR documents and establishing historical design guidelines for the downtown portion of the City. Facilitated and or conducted community workshops in the City of Isleton regarding development, updated Historical Design Guidelines, Zoning Ordinance and General Plan update and projects identified in the updated 5-year redevelopment plan. While employed with Willdan, additional duties included working with California Department of Parks regarding the Bay Area bike trail to Sacramento proposal, preparing Statements of Qualification, Respond to Requests for Proposals, and assist in marketing. Other responsibilities included project manage a team of assistant and associate planners working on four housing element updates including housing inventories for the City of Woodland, City of Lincoln, City of Isleton and City of Wasco. Present staff reports to Planning Commission, City Council and Redevelopment Agency meetings. Assist and facilitate public workshops, meetings and providing GIS support.

2005 – 2008: El Dorado County Community Development. Senior Planner. Responsibilities included review and processing land use entitlements subject to CEQA review and documentation. Process tentative and final subdivision maps subject to CEQA documentation; assisted in developing a screening process for land use entitlement requests that required General Plan consistency analysis. Facilitate meetings with applicants and staff and present staff report to the planning commission. Assist the County's Planning Department in regards to siting Wireless Telecommunication Facilities and review projects that required General Plan findings of consistency, Additional duties included overseeing and providing management support for the County's satellite office located in El Dorado Hills California.

2004 – 2005: El Dorado County Department of Transportation. Senior Planner. Duties Performed: Working on updating the County's traffic impact/Capital Improvement Program, coordinate with Fehr & Peers on traffic modeling as part of this program and Muni-Financial regarding the costs and financial obligations required in upgrading the County and State Highway road infrastructure systems in El Dorado County. Assist EDC-DOT with storm water permitting requirements and assist with facilitating meetings with the traffic impact fee committee.

Resume John Heiser, AICP

2001 – 2004: City of Marina. Associate Planner. Responsibilities included project planner/manager working on several redevelopment projects, subdivisions, housing and mixed use developments located on former Fort Ord Military Base and Airport and within the City limits. These projects required coordinated efforts between local, state and federal agencies as well as the Fort Ord Reuse Authority, the County's airport committee and both California State and University of California. Process and approve land use entitlement requests requiring CEQA documentation. Project planner/manager for the City's Pedestrian and Bicycle Master Plan and assisted with the updated Downtown Specific Plan. Update the City's entire Zoning Ordinance including the Airport, Zoning maps and policy sections of the updated General Plan. Created the City's Wireless Telecommunication Ordinance and Village Homes-Mixed Use Zoning Ordinance. Project manager updating the City's Airport Design Guidelines and facilitate lease agreements at the City's Airport and on former Fort Ord. Assist the public counter section of current planning, facilitate the architectural review committee meetings and provide GIS mapping support.

2000 – 2001: Santa Barbara. Planner III. Project manager of subdivision application requests and multi-family dwellings located on environmentally constrained parcels, process wireless telecommunication facilities throughout the County, review and process complex discretionary projects requiring CEQA documentation. Manage and administer consultant contracts and assist the public counter section of current planning.

1999 – 1999: Max P. Bacerra & Associates. Contract Planner. Project manager of two housing surveys and housing element update documents for the City of Arvin and McFarland. Project manage a 5-year Redevelopment Plan and assist with block grant proposals.

1998 – 1998: El Dorado County. Contract Planner. Responsibilities included but not limited to assisting the public counter section of current planning and plan checking both residential and commercial projects for Zoning, Specific Plan and General Plan policy consistency.

1992 – 1997: Modoc County. Planner II. Project planner/manager for current and long range planning projects. Work efforts included updating the County's Zoning Ordinance and General Plan, Housing Element and providing planning staff services for the City of Alturas. Provide Code Enforcement services for both the County and City of Alturas. Develop a recreational trails map and guide for the County. Prepared for the City of Alturas a Historical Design Guidelines document. Process land use entitlements requiring CEQA review and documentation such as subdivisions and surface mines subject to SMARA and State requirements. Prepare and present staff reports to the City Planning Commission and City Council along with presenting staff reports to the County Planning Commission and Board of Supervisors. Assist the public counter section of current planning. Provide code enforcement assistance and project manage the County's new E-911 addressing system.

1991 – 1992: El Dorado County. Associate Planner. Responsibilities included but not limited to assisting the public counter section of current planning and plan checking both residential and commercial projects for Zoning, Specific Plan and General Plan policy consistency.

1991 – 1992: El Dorado County. Building Technician I. Assist the public counter section of the building department, review and plan check building permit applications.

1991 – 1992: Harland Bartholomew and Associates. Intern Planner. Assist with data collection for CEQA documents and General Plans.

1988 – 1988: QUAD Consultants. Intern Planner. Assist with data collection for CEQA documents by collecting field data and or research data collection.

PROJECTS

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City of Alturas, CA
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Site Planning

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City of Isleton, updated Downtown Historic Design Guidelines, 2008.

City of Isleton, updated 5-year redevelopment plan. 2007-2008.

City of Wasco, CA
City of Wasco, Downtown Historic Design Guidelines update, 2009.

Tulare County, CA
Tulare County, siting criteria for utility scale Solar PV electrical generating facilities. 2010

Transportation Planning

City of Marina, CA
City of Marina, Pedestrian and Bicycle Master Plan, 2003-2004.

El Dorado County, CA
El Dorado County Development Fee Impact Study for County and State Highway Infrastructure Improvements, 2004-2005

MEMBERSHIPS, REGISTRATIONS, AND CERTIFICATES

American Institute for Certified Planners (AICP)
American Planning Associations (APA)

AWARDS

American Planning Association, California Chapter, Central Section, Award for "Innovation in Green Community Planning - first place: Tulare County Resource Management Agency Solar Facility Review Process," 2011

Transportation Agency Monterey County, Award for the City of Marina Pedestrian and Bicycle Master Plan, 2004

DECLARATION OF
WENJUN QIAN

I, Wenjun Qian, declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting, Transmission and Environmental Protection Division as an Air Resources Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on Air Quality, Air Quality Appendix AIR-1: Greenhouse Gas Emissions, Traffic and Transportation Appendix TT-1: Plume Velocity Analysis, and Visual Resources Appendix VR-1: Visible Plume Modeling Analysis for the Huntington Beach Energy Project Amendment, based on my independent analysis of the Petition to Amend and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and, if called as a witness, could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 11/28/2016 Signed: [signature]

At: Sacramento, California

Wenjun Qian, Ph.D., P.E.

Professional Experience

Air Resources Engineer ***(July 2010 – Present)***
California Energy Commission, Siting Transmission and Environmental Protection Division

Currently acting as air quality technical staff on siting projects filed with the Energy Commission, including El Segundo, Russell City, Palomar, Oakley, Huntington Beach etc. Specific responsibilities include the following:

- Analyze the impacts of the construction and operation of large power generation projects on air quality, Green House Gas and climate change
- Determine the conformance to applicable U.S. EPA, ARB and local air district regulations and standards
- Investigate and recommend appropriate emission mitigation measures
- Prepare air quality staff assessments and technical testimony
- Develop and monitor air quality compliance plans
- Review and evaluate U.S. EPA, ARB, and local air district air quality rules and regulations
- Collect, analyze, and evaluate data for the effects of air pollutants and power plant emissions on human health and the environment
- Assist staff in other technical areas by evaluating nitrogen deposition, thermal plume, and visible plume impacts from power plants

Research Assistant ***(Sept. 2005 – June 2010)***
University of California, Riverside, Mechanical Engineering

- Evaluated air quality impact of distributed generations in South Coast Air Basin of California
- Estimated air quality impact from the key power plant of Los Angeles Department of Water and Power in shoreline urban areas
- Improved air quality model results by evaluation with experimental data
- Prepared and presented multiple comprehensive reports, journal papers, and conference papers

Education

PhD Mechanical Engineering, University of California, Riverside (August 2010)
MS Mechanical Engineering, George Washington University (August 2005)
BS Mechanical Engineering, Shanghai Jiao Tong University (June 2004)

DECLARATION OF

Dave Vidaver, Electric Generation System Program Specialist II

I, Dave Vidaver, declare as follows:

1. I am presently employed by the California Energy Commission in the Supply Analysis Office of the Energy Assessments Division as an Electric Generation System Program Specialist II.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on Air Quality and Alternatives for the Huntington Beach Enery Project PTA FSA Part 2 based on my independent analysis of the Palmdale Energy Project and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 11/28/16 Signed: David Vidaver

At: Sacramento, California

Dave Vidaver
Supply Analysis Office
Energy Assessments Division
California Energy Commission
(916) 654-4656
david.vidaver@energy. ca.gov

Employment (all with the California Energy Commission)

Electric Generation System Program Specialist II, Electricity Analysis Office 2011 – present

> Senior analyst responsible for evaluation of procurement, resource adequacy and renewable generation development policies, potential impacts of generation resource development on greenhouse gas emissions.

Electric Generation System Specialist III, Electricity Analysis Office, 2005 - 2011

> Supervisor of Procurement and Resource Adequacy Unit, supervise nine staff responsible for evaluating utility procurement and resource adequacy, combined heat and power and distributed generation issues, role of aging and once-through cooled power plants, compiling and maintaining office databases.

Energy Commission Specialist II, Demand Analysis Office, 2005

> Monitoring near-term load growth at utility and regional level across the WECC; assessing load-temperature relationships for California and major western utilities and long-term changes in temperatures and load-temperature relationships.

Electric Generation System Specialist II, Electricity Analysis Office 2002 – 2005

> Supervisor of Electricity System Modeling Unit; supervised four staff responsible for studies of resource adequacy, market price forecasts, emissions and fuel use studies, assessments of market conditions, role of aging power plants; contributing and principal author of numerous reports, papers, and presentations,

Electric Generation System Specialist I, Electricity Analysis Office, 1998 – 2002

> Simulation modeling of WECC for studies of resource adequacy, market price forecasts, emissions and fuel use studies; assessments of market conditions; contributing and principal author of numerous papers, reports and presentations.

Education

BA, Political Science, University of California, Berkeley
MS, Agricultural Economics, University of California, Davis

Additional Information

Member of the Northwest Power and Conservation Council's Generation Resource Committee, which characterizes the cost and performance of generation technologies for studies undertaken in support of the Council's 5-year power plans; numerous reports at conferences and symposia on topics ranging from natural gas demand in California's electricity sector to implementation of resource adequacy measures in California during 2001- 2004; participant in collaborative proceedings with CPUC (resource adequacy, long-term procurement).

DECLARATION OF
HUEI-AN (ANN) CHU

I, Huei-An (Ann) Chu, declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting, Transmission and Environmental Protection Division as an Air Resources Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Public Health** for the **Huntington Beach Energy Project Amendment**, based on my independent analysis of the Petition to Amend and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and, if called as a witness, could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: __11/28/2016__ Signed: Huei-An Chu

At: Sacramento, California

Huei-An (Ann) Chu

1516 Ninth Street, MS-46, Sacramento, CA 95815
Phone: **(916) 651-0965** , Email: Ann.Chu@energy.ca.gov

EDUCATION

PhD, Environmental Sciences and Engineering, 05/2006
School of Public Health, University of North Carolina at Chapel Hill
Area of Specialization: Environmental Risk Assessment, Environmental Management and Policy, Risk-Based Regulation, Biostatistics, Environmental Epidemiology

MEM, Environmental Management, 05/2000
School of Forestry and Environmental Studies, Yale University, New Haven, CT

MS, Environmental Engineering, 06/1998
National Taiwan University, Taipei, Taiwan

BA, Geography, with honors, 06/1996
National Taiwan University, Taipei, Taiwan

SKILLS

Language: Fluent in Chinese and English.

Computer software and programming skills: HARP, SAS, Stata, Minitab, ArcGIS, ArcView, ArcInfo, Stella, Crystal Ball, ISC, ERMapper, Microsoft Excel, PowerPoint, Word.

WORK EXPERIENCE

Air Resources Engineer, California Energy Commission, 1/12/2012 - Present
- Independently performs responsible, varied analyses assessing air quality and public health impacts of energy resource use and large electric power generation projects in California.
- Model air quality and public health impacts of stationary sources using HARP (Hot Spot Analysis and Reporting Program).
- Identify air quality and public health impacts of stationary sources and measures to mitigate these impacts following California Environmental Quality Act and regulations of US EPA (including the National Environmental Policy Act), ARB, and the Districts.
- Collect, analyze, and evaluate data on the effects of air pollutants and power plant emissions on human health, and the environment.
- Ensure conditions of certification are met and recommending enforcement actions for violations.

Research Associate, Taiwan Development Institute, 10/01/2010 – 12/31/2011
- Provided professional consultation for the environmental risk assessment of Taiwan's techno-industrial development initiatives
- Reviewed the environmental risk assessment reports of Taiwan's techno-industrial development initiatives
- Presented in various distinguished lecturer series about environmental risk assessment

Consultant, Chu Consulting, 08/2007 - 07/2010
- Conducted a cumulative risk assessment to evaluate the risk associated with the emissions of VOCs from a petrochemical plants in southern Taiwan
- Used EPA's ISC3 model (based on Gaussian dispersion model) to simulate the dispersion and deposition of VOCs from this petrochemical plant to the neighboring areas, then used ArcGIS to spatially combine the population data and VOC simulation data (and further calculated risks)

- Built a framework of risk-based decision making to set the emission levels of VOCs to reduce people's exposure and the risk of experiencing health problems
- Presented in conference: SRA 2007
- Awarded: CSU-Chico BBS Faculty Travel Funds (2007)

Environmental Justice Intern, Clean Water for North Carolina (CWFNC), Summer, 2005

- Reviewed and critiqued key state environmental policies and the federal EPA Public Participation Policy.
- Interviewed impacted communities, member organizations of the NC Environmental Justice Network, state policy officials about how those policies are actually implemented.
- Wrote a report about the survey and review of environmental justice needs for key state policies.
- Report Publication: "Achieving Environmental Justice in North Carolina Public Participation Policy" (Aug, 2005).

Volunteer, New Haven Recycles and Yale Recycling, 08/1998 – 05/2000

- Promoted recycling and conservation
- Checked trash cans (chosen randomly) and recycling bins at each entryway of residential college, then gave grades.

Volunteer, Urban Resource Initiative (URI), Summer, 1998

- Planted trees for local community of New Haven for a better and sustainable environment

RESEARCH EXPERIENCE

Postdoctoral Research

Department of Public Health Sciences, University of California, Davis, 07/01/2010 - present
Research advisor: Dr. Deborah H. Bennett and Dr. Irva Hertz-Picciotto

- Work on two projects: NIEHS-funded ***Childhood Autism Risks from Genetics and Environment (CHARGE)*** and EPA-funded ***Study of Use of Products and Exposure Related Behavior*** **(*SUPERB)***.
- Perform statistical and quantitative analyses with SAS to analyze collected house dust data and children's urine concentrations of metabolites.
- Conduct exposure assessment to investigate if pesticides, flame retardants, and phthalates are risk factors for children autism.
- Conduct exposure assessment to explore the relationships between children's exposure to phthalate, benzophenone-3 (oxybenzone), triclosan, and parabens, and the use of personal care products.
- Produce scholarly peer-reviewed publications of methodology and findings, and write the final reports of both projects.

Carolina Environmental Program, University of North Carolina at Chapel Hill, 01/01/2006 – 12/31/2006
Research advisor: Dr. Douglas J. Crawford-Brown

- Applied a framework of risk-based decision-making to perchlorate in drinking water. (Awarded: SRA Annual Meeting Travel Award 2006)
- Conducted a material and energy flow analysis (MEFA) to quantify the overall environmental impact of Bank of America operations, and quantitatively analyze the strategies BOA might adopt to reduce these impacts and achieve sustainability. (Report Publication: "Environmental Footprint Assessment")

Doctoral Research, 08/2000-12/2005

Department of Environmental Sciences and Engineering, School of Public Health, University of North Carolina at Chapel Hill
Research advisor: Dr. Douglas J. Crawford-Brown

- Dissertation topic: "**A framework of Risk-Based Decision Making by Characterizing Variability and Uncertainty Probabilistically: Using Arsenic in Drinking Water as an Example**".
- Conducted risk assessment for arsenic in drinking water.
- Conducted theoretical analysis on the variability and uncertainty issues of risk assessment.

- Conducted a meta-analysis to improve dose-response assessment.
- Conducted analytical and numerical analysis to build a new framework of risk-based decision-making which can be applied coherently across the regulation decisions for different contaminants.
- Presented in conferences: APPAM (2004), SRA (2004, 2005 and 2006), DESE Seminar (2005), CEP Symposium on Safe Drinking Water (2006).
- Awarded: SRA Annual Meeting Student Travel Award (2004 & 2005), UNC-CH Graduate School Travel Grants (2004), UCIS Doctoral Research Travel Awards (2002).

Master's Research

School of Forestry and Environmental Studies, Yale University, 08/1999 - 06/2000
Research advisor: Dr. Xuhui Lee

- Master's project: "**Forest Stand Dynamics and Carbon Cycle**".
- Research project: "Monitoring Forest CO_2 Uptaking"
- Used remote sensing (ERMapper) to investigate the role of forest in the uptake of CO_2.
- Awarded from Teresa Heinz Scholars for Environmental Research Program (2000) and Klemme Award (1999).

Graduate Institute of Environmental Engineering, National Taiwan University, 06/1996 - 06/1998
Research advisor: Dr. Shang-Lien Loh

- Master's thesis: "**The Loads of Air Pollutants from Urban Areas on a Neighboring Dam and its Water Quality**"
- Research Projects: "Research on Air Pollutant Deposition in Urban Areas" and "the Fate and Flow of Recyclable Materials"
- Used Gaussian's Dispersion model (ISC3) to investigate the loads of air pollutants on dam water.

TEACHING EXPERIENCE

Lecturer

Department of Environmental Studies, California State University at Sacramento

- Environmental Politics and Policy, Fall 2011

Department of Geological & Environmental Science, California State University at Chico

- Environmental Risk Assessment, Spring 2009 & 2010
- Applied Ecology, Spring 2008
- Pollution Ecology, Fall, 2007

Department of Geography & Planning, California State University at Chico

- Seminar in Applied Geography & Planning – Environmental Regulation and Policy, Fall, 2007

Department of Forestry and Environmental Resources, North Carolina State University

- Environmental Regulation, Fall, 2006

Teaching Assistant

Department of Environmental Sciences and Engineering, UNC-Chapel Hill

- Environmental Risk Assessment, Spring, 2002
- Introduction to Environmental Science, Fall, 2001
- Analysis and Solution of Environmental Problems, Fall, 2001

Lab Instructor

Department of Environmental Sciences and Engineering, UNC-Chapel Hill

- Biology for Environmental Science, Fall, 2000

Graduate Institute of Environmental Engineering, National Taiwan University

- Water Quality Analysis, Fall, 1997

AWARDS and HONORS

- CSU-Chico BBS Faculty Travel Funds, 2007
- Member of Society of Risk Analysis (SRA), 2006-2008
- SRA Annual Meeting Student Travel Award, 2004-2006
- UNC-CH Graduate School Travel Grants, 2004
- Member of Association for Public Policy Analysis and Management (APPAM), 2004-2005
- UCIS Doctoral Research Travel Awards, 2002
- Graduate Student Teaching and Research Assistantships, 2000-2005
- Teresa Heinz Scholars for Environmental Research Program, 2000
- Yale Forestry & Environmental Studies, Klemme Award, 1999

PUBLICATIONS (SELECTED LIST)

Huei-An Chu*,* Deborah H. Bennett, Irva Hertz-Picciotto, "Phthalates in relation to autism and developmental delay: Exploratory analyses from the CHARGE Study". (In preparation)

Huei-An Chu*,* Deborah H. Bennett, Irva Hertz-Picciotto, "Peronal Care Products: Possible Sources of Children Phthalate Exposure". (In preparation)

Huei-An Chu and Douglas J. Crawford-Brown, "A Probabilistic Risk Assessment Framework to Quantify the Protectiveness of Alternative MCLs for Arsenic in Drinking Water", *Journal of American Water Works Association*. (Being revised)

Huei-An Chu and Douglas J. Crawford-Brown, "Letter to the Editor: Inorganic Arsenic in Drinking Water and Bladder Cancer: A Meta-Analysis in Dose-Response Assessment", *International Journal of Environmental Research and Public Health*, 2007, 4(4), 340-341.

Huei-An Chu and Douglas J. Crawford-Brown, "Inorganic Arsenic in Drinking Water and Bladder Cancer: A Meta-Analysis in Dose-Response Assessment", *International Journal of Environmental Research and Public Health* 2006, 3(4), 316-322.

S.L. Lo and **H.A. Chu**, "Evaluation of Atmospheric Deposition of Nitrogen to the Feitsui Reservoir in Taipei", *Water Science & Technolog*y, 2006, 53(2), 337-344.

CSE Consulting and the UNC Carolina Environmental Program (CEP), "Environmental Footprint Assessment", Report for Bank of America, Aug, 2006.

Huei-An Chu, "Achieving Environmental Justice in North Carolina Public Participation Policy", Report for Clean Water for North Carolina (CWFNC), Aug, 2005.

Huei-An Chu, "Arsenic and its Health Implications", Report for University Center for International Studies Graduate Travel Awards, 2002.

PRESENTATIONS (SELECTED LIST)

Guest Speaker, "Human Health Risk Assessment – Arsenic in Drinking Water as an Example". Tunghai University, Taichuang, Taiwan. (December 16th, 2010)

Guest Speaker, "Environmental Problems in Developing Countries", Course Title: <u>Developing Countries</u>, Department of Economics, CSU-Chico (October 31st, 2008)

"Cumulative Risk Assessment for Volatile Organic Compounds (VOCs) from Petrochemical Plants in Southern Taiwan". Oral Presentation in Society of Risk Analysis (SRA) 2007 Annual Meeting, San Antonio, TX. (December, 2007)

Guest Speaker, "Arsenic in Drinking Water", Course Title: <u>Environmental Geology</u>, CSU-Chico. (November 13th, 2007)

"Risk-Based Environmental Regulation for Arsenic in Drinking Water", Oral Presentation in Department of Environmental Health Seminar, East Tennessee State University (February 2nd, 2007)

"A Framework of Risk-based Decision Making by Characterizing Variability and Uncertainty Probabilistically: Using Arsenic in Dinking Water as an Example", Oral Presentation in Society of Risk Analysis (SRA) 2006 Annual Meeting, Baltimore. MD. (December, 2006)

"A New Policy Tool to Choose Water Quality Goals under Uncertainty", Poster Presentation in Society of Risk Analysis (SRA) 2006 Annual Meeting, Baltimore. MD. (December, 2006)

"A framework of Risk-Based Decision Making by Characterizing Variability and Uncertainty Probabilistically: Using Arsenic in Drinking Water as an Example", Oral Presentation for National Center for Environmental Assessment (NCEA), Environmental Protection Agency (EAP). (October 26th, 2006)

"Probabilistic Risk Assessment for Arsenic in Drinking Water", Poster Presentation in Carolina Environmental Program (CEP) 2006 Symposium on Safe Drinking Water, Chapel Hill, NC. (March, 2006)

"Probabilistic Risk and Margins of Safety for Water Borne Arsenic", Poster Platform Presentation in Society of Risk Analysis (SRA) 2005 Annual Meeting, Orlando, FL. (December, 2005)

"Using Meta-Analysis in Dose-Response Analysis – Risk Assessment of Arsenic in Drinking Water as an Example", Poster Platform Presentation in Society of Risk Analysis (SRA) 2004 Annual Meeting, Palm Springs, CA. (December, 2004)

Preparation Team

HUNTINGTON BEACH ENERGY PROJECT PETITION TO AMEND (12-AFC-02C) FINAL STAFF ASSESSMENT – PART 2 PREPARATION TEAM

Executive Summary .... John Heiser, AICP

Introduction .... John Heiser, AICP

Project Description .... John Heiser, AICP

Environmental Assessment

Air Quality .... Wenjun Qian, Ph. D., P.E., David Vidaver

Public Health .... Huei-An (Ann) Chu, Ph. D.

Supplemental Testimony

Hazardous Materials Management .... Brett Fooks, PE and Geoff Lesh, PE

Land Use .... Steven Kerr

Noise and Vibration .... Edward Brady and Shahab Khoshmashrab

Traffic and Transportation .... John Hope

Visual Resources .... Jeanine Hinde

Water Resources .... Mike Conway

Worker Safety and Fire Protection .... Brett Fooks, PE and Geoff Lesh, PE

Project Attorney .... Kevin Bell

Project Assistant .... Marichka Haws

Supplemental Testimony

HAZARDOUS MATERIALS MANAGEMENT

Supplemental Testimony of Brett Fooks, PE and Geoff Lesh, PE

This testimony supplements and clarifies the information in the Final Staff Assessment Part 1. Staff has received additional comments from the city of Huntington Beach and staff has provided responses to these comments below.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Comment: *Section 4.4: Add a statement to the Hazardous Materials section that the AES site is required to disclose all hazardous materials and quantities to the California Environmental Reporting System (CERS) as required by the Huntington Beach Fire Department Hazardous Materials Program (**CHPWD 2016e**).*

Response: Staff has not added the above statement to the Hazardous Materials Management section of the Final Staff Assessment. The project owner would be required to comply with all laws, ordinances, regulations and standards, which includes the CERS reporting requirements found under Section 25508 of the California Health and Safety Code. In addition, the condition of certification **HAZ-2** requires the project owner to submit a Hazardous Materials Business Plan to the local Certified Unified Public Agency, which is the Huntington Beach Fire Department, for review and comment.

REFERENCES

CHPWD 2016e - Huntington Beach Department of Community Development (TN 214618). Comments regarding final Staff Assessment Part 1, dated December 1, 2016. Submitted to CEC/Docket Unit on December 2, 2016.

LAND USE

Supplemental Testimony of Steven Kerr

STAFF'S RESPONSE TO PROJECT OWNER'S SUPPLEMENTAL TESTIMONY (TN 214455)

Energy Commission Siting Regulations, Title 20 California Code of Regulations, Chapter 5, Article 6, Appendix B(g)(3)(C) requires that the following information be included in an Application for Certification (AFC) to the Energy Commission:

> *"A discussion of the compatibility of the legal status of the parcel(s) on which the project is proposed. If the proposed site consists of more than one legal parcel, describe the method and timetable for merging or otherwise combining those parcels so that the proposed project, excluding linears and temporary laydown or staging area, will be located on a single legal parcel. The merger need not occur prior to a decision on the Application but must be completed prior to the start of construction."*

Accordingly, the licensed Huntington Beach Energy Project (HBEP) AFC Section 5.6.1 included the following statement[1]:

> *"The Assessor's Parcel Numbers for the HBEP site are 114-150-82 and 114-150-96. HBEP will utilize 28.6 acres, using only a portion of APN 114-150-96. Following project approval, the project owner will obtain a lot line adjustment to establish a single parcel for the 28.6 acre HBEP site, prior to commencing construction of the first power block."*

To ensure compliance with the above siting regulation because the project owner would be obtaining the lot line adjustment following the decision, but prior to the start of construction of the first power block, the Energy Commission included Condition of Certification **LAND-1** in their Final Commission Decision (TN 203309) for the licensed HBEP as follows:

LAND-1 The project owner shall comply with Appendix B(g)(3)(c) of the Siting Regulations (Title 20, California Code of Regulations) by ensuring that the HBEP site, excluding linear and temporary lay down or staging area will be located on a single legal parcel.

Verification: Prior to construction of the first power block, the project owner shall submit evidence to the compliance project manager (CPM), indicating approval of a Lot Line Adjustment by the city of Huntington Beach, establishing a single parcel for the 28.6 acre HBEP site. The submittal to the CPM shall include evidence of compliance with all conditions and requirements associated with the approval of the Lot Line Adjustment by the city.

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[1] The Land Use section of the AFC for the licensed HBEP may be viewed here: http://www.energy.ca.gov/sitingcases/huntington_beach_energy/documents/applicant/AFC/Volume%201/HBEP_5.6_Land Use.pdf

Due to an increase in the size of the project site from 28.6 acres for the licensed HBEP to 30 acres for the amended HBEP, staff recommended the following minor update to **LAND-1** in their Final Staff Assessment Part 1 for the amended HBEP (TN 214025). (**Note:** Deleted text is in ~~strikethrough~~, and new text is in **<u>bold and underlined</u>**)

LAND-1 The project owner shall comply with Appendix B(g)(3)(c) of the Siting Regulations (Title 20, California Code of Regulations) by ensuring that the HBEP site, excluding linear and temporary lay down or staging area will be located on a single legal parcel.

<u>Verification:</u> Prior to construction of the first power block, the project owner shall submit evidence to the compliance project manager (CPM), indicating approval of a Lot Line Adjustment by the city of Huntington Beach, establishing a single parcel for the ~~28.6~~ **30**-acre HBEP site. The submittal to the CPM shall include evidence of compliance with all conditions and requirements associated with the approval of the Lot Line Adjustment by the city.

Following publication of the FSA, in their opening testimony (TN 214211) and supplemental testimony (TN 214455), the project owner identified potential timing constraints in obtaining the lot line adjustment prior to construction of the first power block and proposed to modify the timing trigger in the **LAND-1** verification to "prior to commercial operation," as set forth below.

LAND-1 The project owner shall comply with Appendix B(g)(3)(c) of the Siting Regulations (Title 20, California Code of Regulations) by ensuring that the HBEP site, excluding linear and temporary lay down or staging area, will be located on a single legal parcel.

<u>Verification:</u> Prior to ~~construction~~ **<u>commercial operation</u>** of the ~~first~~ **<u>combined-cycle gas turbine (CCGT)</u>** power block, the project owner shall submit evidence to the compliance project manager (CPM) indicating approval of a Lot Line Adjustment, **<u>or other action</u>** by the city of Huntington Beach, establishing a single parcel for the **<u>CCGT power block and related facilities</u>** ~~28.6 acre HBEP site~~. The submittal to the CPM shall include evidence of compliance with all conditions and requirements associated with the approval of the Lot Line Adjustment, **<u>or other action</u>** by the city. **<u>Prior to construction of the second power block, the project owner shall submit evidence to the CPM indicating approval of a Lot Line Adjustment, or other action by the city of Huntington Beach, establishing a single parcel for the 30-acre HBEP site. The submittal to the CPM shall include evidence of compliance with all conditions and requirements associated with the approval of the Lot Line Adjustment or other action by the city.</u>**

Response: While the project owner's proposed modifications to **LAND-1** would not comply exactly with the above referenced siting regulation by ensuring the lot line adjustment or other action would occur prior to the start of construction, staff concludes the modified condition provides a reasonable timetable given the project's timing constraints and would still ensure that the project will be located on a single legal parcel.

STAFF'S RESPONSE TO CITY OF HUNTINGTON BEACH FSA PART 1 COMMENTS (TN 214618)

On December 2, 2016 staff received a letter including the city of Huntington Beach's comments regarding the FSA Part 1 for the amended HBEP. The letter included the following comment regarding the Land Use section:

> 7. *Page 4.5-12 Land Use: Condition of Certification* ***LAND-1*** *states that city approval of a Lot Line Adjustment is required. Based on the site's location in the Coastal Zone a coastal development permit is required in conjunction with any proposed lot line adjustment.*

Response: As stated above in "Staff's Response to the Project Owner's Supplemental Testimony," the project owner included as part of the project in the AFC that they will obtain a lot line adjustment (or other action) from the city to comply with Siting Regulations. According to Public Resources Code section 25500, the issuance of a certificate by the Energy Commission shall be in lieu of any permit required by a local agency. Therefore, the Energy Commission's certification of HBEP is in lieu of the city's issuance of a coastal development permit associated with the development of the project, including for the associated lot line adjustment. However, the actual processing of the lot line adjustment must be done by the city as it is the process that is used to record changes to property lines of existing legal parcels and not a permit that the Energy Commission would have exclusive jurisdiction over.

NOISE AND VIBRATION

Supplemental Testimony of Edward Brady and Shahab Khoshmashrab

COMMENTS AND RESPONSES

This **Noise and Vibration** supplemental testimony addresses the comments from the city of Huntington Beach (city) on the Huntington Beach Energy Project Petition to Amend (HBEP) Final Staff Assessment Part 1 (FSA Part 1) (CHPWD 2016e). Comments relating to noise are shown below, as well as staff's responses to those comments. Staff's responses are considered supplemental testimony to FSA Part 1.

Comment: *The city inquires about the potential noise impacts of activities at the Plains All-American Tank Farm (Plains site). The residents on the east side of Magnolia Street have expressed their concern regarding potential noise impacts from the construction laydown activities and they should be assured any potential impacts have been mitigated. No construction staging, warm-up activity, arrival of construction workers at off-site parking facilities, on-site, or queuing outside the facility or outside the Plains site, should occur before 7:00 a.m.*

Staff's Response: The construction laydown activities would include loading, unloading, and stacking of construction supplies, preparation and cutting of materials for transport to the HBEP site, and equipment operations and materials assembly. The noise levels from many of these activities are characteristically similar to construction and demolition activities, but generally on a smaller scale.

Equipment operations and materials assembly may have the potential to create considerable noise in the surrounding area. Examples may include noise from welder torch, pneumatic tools, and impact wrench used for assembly, and chain saw used for cutting. They typically generate noise levels of 75 to 85 dBA at a 50-foot distance (Federal Highway Administration Construction Noise Handbook, § 9.4.1, Table 9.1).

The closest residents to the Plains site are represented by M3 in **Noise and Vibration Figure 1** below. These are the houses in the residential subdivision that runs along Magnolia Street. The existing ambient noise level at this location is 54 dBA L_{eq}. Since the layout of the 22-acre Plains site has not yet been determined, the location of the six-acre laydown area within this site is not yet known. Based on the 75 to 85 dBA range from the above activities, increases in the existing ambient level could reach between 5 and 13 dBA depending on the intensity of work and location of these activities within the site (approximately 300 to 900 feet from M3). Thus, these activities could potentially create a significant noise impact at these residences.

The existing masonry sound wall along Magnolia Street would help to reduce this impact, but to further control the noise, staff recommends some revisions to Condition of Certification **NOISE-6**. These revisions include requiring the laydown activities to be performed in a manner that would avoid excessive noise and reduce the potential for noise complaints as much as practicable, and prohibiting construction staging and warm-up activities from occurring outside the city's allowable construction hours. The revisions to Condition **NOISE-6** published in the FSA Part 1 are **bolded and double-underlined**, and shown below.

NOISE-6 from the FSA Part 1 requires that in order to reduce noise, construction equipment generating excessive noise be updated or replaced; temporary acoustic barriers be installed around stationary construction noise sources; construction equipment be reoriented; and construction staging areas be relocated. These mitigation measures apply to all project-related construction work, including those that would occur at the Plains site. However, to clearly state this, staff has added new text to **NOISE-6**. Staff notes that additional mitigation measures beyond those outlined in **NOISE-6** may be needed, but based on the staff's experience with many power plant projects under the Energy Commission's permitting jurisdiction, it is more effective to allow the project owner to coordinate the specifics of those efforts with its construction contractor. In this way, and due to the dynamic nature of construction-related work, the contractor has the ability to implement noise attenuation measures more quickly and more effectively.

Additionally, in this supplemental testimony, **Traffic and Transportation** Condition of Certification **TRANS-3** has been expanded to prohibit arrival of construction workers at off-site parking facilities, on-site, or queuing outside the facility or outside the Plains site, before 7:00 a.m. This will address both traffic and noise concerns.

Comment: *The city requests that construction work outside of the city's allowable construction hours be mitigated to reduce potential impacts to sensitive receptors to the maximum extent feasible.*

Staff's Response: **NOISE-6** in FSA Part 1 includes the same requirements associated with nighttime work as those specified in **NOISE-6** in the 2014 Energy Commission Final Decision (Licensed HBDP CEC 2014bb). According to **NOISE-6**, the project owner must submit a request to staff for review and approval and simultaneously send a copy to the city for review and comment, soliciting the city's review and comment to the CPM. This letter must specify the activities that need to occur outside of the city's allowable construction days and times; the need for such activities; the days, dates, and times during which these activities will occur; the approximate distance of activities to residential and sensitive receptors; and the expected sound levels at these receptors. In addition, **NOISE-6** requires that the project owner notify the residents and property owners within one-half mile of the project site of the request. In this notification, the project owner must state that it will perform this activity in a manner to ensure excessive noise is prohibited as much as practicable.

As to specifying, in the conditions of certification, particular methods to reduce temporary noise such as those associated with concrete pour at night for HBEP, the staff's experience with power plant projects has shown that allowing the project owner to directly work with its construction contractor to utilize specific techniques for noise attenuation has worked better. As mentioned above, due to the dynamic nature of construction-related activities, the contractor has the ability to implement noise attenuation measures more quickly and more effectively.

Staff concludes that **NOISE-6,** as it appeared in FSA Part 1, satisfactorily addresses the city's concern about nighttime construction work. The entire FSA Part 1 **NOISE-6** has been reproduced below, with the staff's proposed revisions to **NOISE-6** **bolded and double-underlined** to address the city's other noise concerns.

REVISED CONDITION OF CERTIFICATION

NOISE-6 CONSTRUCTION RESTRICTIONS

Heavy equipment operation and noisy[~~2~~**3**] construction work relating to any project features, including **construction staging and warm-up activities at the Plains All-American Tank Farm (Plains) site**, and pile driving, shall be restricted to the times delineated below:

Mondays through Saturdays:	7:00 a.m. to 8:00 p.m.
Sundays and Federal Holidays:	Construction not allowed

Limited construction activities may be performed outside of the above hours, with CPM approval as set forth below.

Haul trucks and other engine-powered equipment shall be equipped with adequate mufflers and other state-required noise attenuation devices. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use (jake braking) shall be limited to emergencies.

Verification: Prior to ground disturbance, the project owner shall transmit to the CPM a statement acknowledging that the above restrictions will be observed throughout the construction of the project.

In consultation with the CPM, construction equipment generating excessive noise[~~3~~**4**] **at the HBEP site as well as at the Plains site** shall be updated or replaced if beneficial in reducing the noise and if feasible. In addition, temporary acoustic barriers shall be installed around stationary construction noise sources if beneficial in reducing the noise and if feasible. The project owner shall reorient construction equipment, and relocate construction staging areas, when possible, to minimize the noise impact at nearest noise-sensitive receptors. **All construction-related activities at the two sites shall be performed in a manner to avoid excessive noise and reduce the potential for noise complaints as much as practicable.**

[~~2~~**3**] ~~Noise~~ **"Noisy" means noise** that draws legitimate complaint (for the definition of "legitimate complaint", see the footnote in Condition of Certification **NOISE-2**)

[~~3~~**4**] ~~Noise~~ **"Excessive noise" means noise** that draws a legitimate complaint (for the definition of "legitimate complaint", see the footnote in Condition of Certification **NOISE-2**)

At least 10 days prior to any heavy equipment operation or noisy construction activities that would occur outside of the above hours, the project owner shall submit a request to the CPM for review and approval and simultaneously send a copy to the city of Huntington Beach for review and comment. The project owner shall provide a copy of the transmittal letter to the city of Huntington Beach soliciting review and comment to the CPM.

The request submitted to the CPM shall specify the activities that need to occur outside of the restricted days and times set forth above; the need for such activities; the days, dates, and times during which these activities will occur; the approximate distance of activities to residential and sensitive receptors; the expected sound levels at these receptors; and a statement that the activities will be performed in a manner to ensure excessive noise is prohibited as much as practicable. At the same time, the project owner shall notify the residents and property owners within one-half mile of the project site of the request. In this notification, the project owner shall state that it will perform this activity in a manner to ensure excessive noise is prohibited as much as practicable.

The project owner shall not perform any heavy equipment operation or noisy construction activities outside of the timeframes set forth above until the CPM has granted the request for exemption. If the exemption is granted, the project owner shall notify the residents and property owners within one-half mile of the project site of the approval of the request. The project owner shall provide copies to the CPM of all transmittal letters to property owners and residents.

REFERENCES

CEC 2014bb - Final Commission Decision (TN 203309). Submitted to CEC/Docket Unit on November 4, 2014.

CHPWD 2016e - Huntington Beach Department of Community Development (TN 214618). Comments regarding final Staff Assessment Part 1, dated December 1, 2016. Submitted to CEC/Docket Unit on December 2, 2016.

NOISE AND VIBRATION - FIGURE 1
Huntington Beach Energy Project - Sound Monitoring Locations

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Additional Responses, Figure 5-7.1R, 1/17/2013, CH2MHILL

STAFF'S RESPONSE TO COMMITTEE COMMENTS (TN 214581)

Committee comment: *The Committee requested clarification on the coordination of the Magnolia Street/Banning Avenue intersection improvements with the city of Huntington Beach.*

Response: The applicant identified in the AFC that "the Project Owner will modify the intersection to a 4-way traffic signal in coordination with the City of Huntington Beach" (page 2-14). Staff analyzed the potential impacts to traffic and transportation with the understanding that the applicant is coordinating with the city of Huntington Beach in the design of the modified intersection. As such, staff's analysis identifies "modification of the intersection to a 4-way traffic signal was occurring in coordination with the city of Huntington Beach engineering and planning departments in regards to design and meeting the city's specifications."

Staff understands the Energy Commission permitting process provides permits for an approved project in-lieu of local permits (e.g., city of Huntington Beach building permit). However, for this particular project-related improvement, staff identified the need for expertise from the city of Huntington Beach in regards to the design of the intersection modification and engineering plan review. The proposed Conditions of Certification **TRANS-4** and **TRANS-8** are written to reflect staff's understanding of the proposed project as a whole, including the intersection modification, and staff's need for local expertise.

Specifically, as part of **TRANS-4**, which is a part of the approved HBEP, the project owner is required to acquire a permit from the city of Huntington Beach for the intersection modification's encroachment into a public right-of-way. **TRANS-4** is a general condition that would require the project owner to coordinate with local agencies (e.g., city, county, Caltrans) for <u>any</u> roadway work. Staff proposes adding **TRANS-8** as a condition to the amended HBEP to work in tandem with **TRANS-4**. As part of the proposed **TRANS-8**, the project owner is required to provide the engineering plan/drawings for the design and reconfiguration of the intersection to the city of Huntington Beach Public Works Department for review and comment.

Together, **TRANS-4** requires the project owner to acquire a general encroachment permit from the city of Huntington Beach and **TRANS-8** requires the project owner to obtain review, comment, and approval for the specific design of the Magnolia Street/Banning Avenue intersection improvements. Both **TRANS-4** and **TRANS-8** are intended to ensure the city of Huntington Beach has opportunity to review and comment prior to any ground disturbance occurring for the intersection modification.

Committee comment: *The Committee requested clarification of the word "assured" and how is replacement parking being provided prior to intersection improvements.*

Response: As identified in the proposed new Condition of Certification **TRANS-9**, replacement parking is required to be provided on a one-to-one basis in conformance with the city of Huntington Beach zoning code. Staff used the word "assured" in conjunction with the previously identified requirement of the city's zoning code. However, staff acknowledges the word "assured" does not fully encompass the intent of the condition to require the replacement parking to be provided prior to removal of any existing parking. In addition, actions required under the verification only obligate the project owner to submit a parking replacement plan but does not explicitly require the replacement parking to be provided prior to removal of any existing parking. Therefore, staff recommends replacing the word "assured" to "provided" as identified below thereby clearly identifying the replacement parking shall actually be provided prior to removing any existing parking.

The following is staff's proposed changes to **TRANS-9** (based on staff's FSA) to further clarify the condition. Text to be removed is shown in double ~~strike through~~ and new text is shown as **bold** and double underlined.

TRANS-9 REPLACEMENT OF STREET PARKING DUE TO RECONFIGURATION OF MAGNOLIA/BANNING INTERSECTION

If existing street parking on Magnolia Street is reduced as a result of the project's reconfiguration of the Magnolia/Banning intersection and the construction of the new entrance to the Plains site, the project owner shall replace the loss of street parking on a one-for-one basis within "walking distance" of the displaced parking spaces as required by Section 231.28 of the city of Huntington Beach Zoning Code. Replacement parking shall be ~~assured~~ provided before removal of any existing parking to ensure no reduction in available parking spaces.

Verification: At least 10 days prior to reduction of existing street parking, the project owner shall submit a parking replacement plan to the city of Huntington Beach for review and comment, and submit to the CPM for review and approval. The plan shall identify the number and location of parking spaces to be removed and the number and location of parking spaces to be replaced.

STAFF'S RESPONSE TO CITY OF HUNTINGTON BEACH COMMENTS (TN 214618)

City comment: *The City previously commented that a Traffic Impact Assessment is required to evaluate the proposed new intersection improvements at Magnolia and Banning. The FSA states that AES is working with the City regarding these proposed improvements. As indicated in comments from Public Works staff below, the City will work with AES to evaluate traffic engineering plans regarding the proposal but we continue to comment that the PSA does not address or conclude this issue adequately*.

Response: The Magnolia Street/Banning Avenue intersection reconfiguration is considered part of the whole of the proposed HBEP for CEQA purposes. As such, the potential environmental impacts to traffic and transportation operations related to the proposed intersection reconfiguration are fully considered in the FSA.

As related to assessing traffic operations at the Magnolia Street/Banning Avenue intersection, as identified on page 4.10-4 of the PSA, implementation of the amended HBEP would result in fewer construction trips than the licensed HBEP. The proposed amended HBEP is estimated to generate 638 daily one-way trips and 312 peak hour trips as compared to the licensed HBEP which was estimated to generate 734 daily trips and 343 peak hour trips. A new analysis of intersection operations during construction (with project conditions) continues to not be necessary for the amended HBEP because the amended project would not increase the number of trips.

However, the FSA fully analyzes operating conditions of Magnolia Street between Garfield Avenue and Yorktown Avenue and intersections nearest the project site. As discussed under the section Construction Traffic Generation (pages 4.10-4 and 4.10-5 of the FSA) and shown in **Traffic and Transportation Table 1** and **Table 2**, the intersections currently operate at LOS A and are estimated to have sufficient capacity to accommodate the increase in project-related trips during both peak hours. This conclusion is based on the minimal increase of traffic along Magnolia Street (3 percent of average annual daily volume) that would occur during construction. Increased traffic generated during construction of the proposed amended HBEP would not have the potential to substantially change the existing operating conditions of Magnolia Street (estimated to operate at LOS C) or intersections which currently operate at LOS A.

Staff continues to recommend the existing Condition of Certification **TRANS-4** to ensure the project owner coordinates with the city of Huntington Beach prior to constructing any improvements to the Magnolia/Banning intersection. Staff is also recommending a new Condition of Certification **TRANS-8** which would require the project owner to provide to the city of Huntington Beach for review and approval engineering drawings/plans for the design and configuration of the Magnolia/Banning intersection.

City comment: *The FSA states that construction activities will occur six days per week from 7:00 AM-8:00 PM, with additional hours needed. The 7:00 AM-8:00 PM hours align with the City's Municipal Noise Code for construction activities with valid building permits. However, the FSA's description of, "Overtime and additional shift work may be required to maintain or enhance the construction schedule," and, " ... additional hours needed," is very concerning to the City. Additionally, construction should be prohibited Sundays and Federal holidays. The City acknowledges the anticipated need for occasional nighttime activity due to critical construction needs (concrete pours) and mitigation measures should reduce potential impacts to sensitive receptors to the maximum extent feasible. The Conditions for Certification should strictly limit nighttime activity and should specify that no construction staging, warm-up activity, arrival of construction workers at off-site parking facilities, on-site, or queuing outside the facility or outside the Plains site, should begin before 7:00 AM.*

Page 4.10-1 2 Traffic and Transportation: The Parking/Staging Plan required in Condition of Certification Trans-3 should be expanded to identify that parking and laydown areas shall operate only during approved construction hours. Additionally, construction workers and equipment/material deliveries shall not be permitted to arrive on site nor stage on surrounding street system prior to 7:00 AM. Furthermore, the text should be amended to reflect that, "The Parking/Staging Plan shall prohibit use of the Huntington Beach City <u>Beach</u> parking area."

Response: Staff has agreed to revise Condition of Certification **TRANS-3** to include restrictions on the hours when delivery trucks and construction workers may arrive. In addition, the revisions include actions required of the project owner if delivery trucks and/or construction workers arrive prior to the restrictive hours. The addition of the text "Beach" also been provided. In response to the prohibition of workers queuing outside the facility, the Parking and Staging Plan requires "for all phases of project construction and operation to require all project-related parking to be on-site or in designated off-site parking areas" thereby prohibiting the queuing of any traffic outside the facility.

The following is staff's proposed changes to **TRANS-3** (based on staff's FSA) incorporating the recommendations of the city. Text to be removed is shown in double ~~strike through~~ and new text is shown as **bold** and <u>double underlined</u>.

TRANS-3 TRAFFIC CONTROL PLAN

The project owner shall prepare and implement a Traffic Control Plan (TCP) for the HBEP's construction and operations traffic. The TCP shall address the movement of workers, vehicles, and materials, including arrival and departure schedules~~ and~~**<u>,</u>** designated workforce~~ and~~**<u>,</u>** delivery routes**<u>, and the operations of shuttle(s) from offsite parking areas</u>**. The project owner shall consult with Caltrans and all applicable local jurisdictions, including, but not limited to, Orange County, Los Angeles County, and the cities of Huntington Beach, Long Beach, and Seal Beach, in the preparation and implementation of the ~~Traffic Control Plan (~~TCP~~)~~. The project owner shall submit the proposed TCP to Caltrans and applicable local jurisdictions in sufficient time for review and comment, and to the CPM for review and approval prior to the proposed start of construction and implementation of the plan.

The Traffic Control Plan ~~(TCP)~~ shall include:

1. Provisions for redirection of construction traffic with a flag person as necessary to ensure traffic safety and minimize interruptions to non-construction related traffic flow,

2. Placement of necessary signage, lighting, and traffic control devices at the project construction site and lay-down areas;

3. A heavy-haul plan addressing the transport and delivery of heavy and oversized loads requiring permits from the California Department of Transportation (Caltrans), other state or federal agencies, and/or the affected local jurisdictions including Los Angeles County, Orange County, city of Long Beach, city of Seal Beach, and city of Huntington Beach;

4. Location and details of construction along affected roadways at night, where permitted;

5. Temporary closure of travel lanes or disruptions to street segments and intersections during construction activities;

6. Traffic diversion plans (in coordination all applicable local jurisdictions and Caltrans) to ensure access during temporary lane/road closures;

7. Access to residential and/or commercial property located near construction work and truck traffic routes;

8. Assurance of access for emergency vehicles to the project site;

9. Advance notification to residents, businesses, emergency providers, and hospitals that would be affected when roads may be partially or completely closed;

10. Identification of safety procedures for exiting and entering the site access gate;

11. Parking/Staging Plan for all phases of project construction and operation to require all project-related parking to be on-site or in designated off-site parking areas. **The Parking/Staging Plan shall identify operation time(s) and route(s) for shuttle(s) from offsite parking areas.** The Parking/Staging Plan shall prohibit use of the Huntington Beach City **Beach** parking area unless the CPM determines that there are insufficient parking spaces available at the other parking facilities identified in this Decision. **The Parking/Staging Plan shall prohibit construction workers from arriving on-site or in designated off-site parking areas prior to allowable construction start times (7 a.m. on weekdays and Saturdays). The Parking/Staging Plan shall prohibit construction workers from arriving on-site or in designated off-site parking areas on Sundays and Federal holidays;**

12. **Timing of truck deliveries to the project site to occur between the hours of 7 a.m. to 8 p.m. on weekdays and Saturdays.**

Verification: At least 60 calendar days prior to the start of construction, the project owner shall submit the TCP to the applicable agencies for review and comment and to the CPM for review and approval. The project owner shall also provide the CPM with a copy of the transmittal letter to the agencies requesting review and comment.

At least 30 calendar days prior to the start of construction, the project owner shall provide copies of any comment letters received from the agencies, along with any changes to the proposed development plan, to the CPM for review and approval.

City comment: *The on-going question of permit authority for off-site improvements remains unresolved. The new Condition of Certification **TRANS-8** describes that the CBO shall review and approve civil engineering plans/drawings for traffic signing, striping, and grading for the off-site intersection improvements at Magnolia Ave. and Banning Street, pedestrian crossings, and replacement parking in the Coastal Zone. However, **TRANS-8** states that the City can only review and comment on the proposed plans. The City will issue grading and Public Works related permits for all off-site improvements.*

Response: The permit issued by the Energy Commission for the construction and operation of a power plant is in-lieu of all other local jurisdiction permits (e.g., building permit). However, the Energy Commission strives to work with local agencies to ensure project proposals satisfy local jurisdiction requirements. In addition, the Energy Commission recognizes the need for local expertise (e.g., city of Huntington Beach Public Works Department staff). For this reason, staff recommends keeping Condition of Certification **TRANS-4** which requires the project owner or its contractor(s) to obtain all required encroachment permits including those from the city of Huntington Beach. Although Condition of Certification **TRANS-8** is written in such a way that the CBO has the authority to approve any engineering plan/drawings, and the city has the ability to review and comment, if the project owner is unable to comply with the requirements specified in Condition of Certification **TRANS-4,** then the applicant would not be able to implement the proposed Magnolia Street/Banning Avenue intersection reconfiguration.

City comment: The City's July 22, 20 16 letter should be referenced.

Response: The FSA refers to the city’s July 22, 2016 letter directly in the text as TN# 212437. Specifically, text in the FSA states:

> Staff received comments on the Preliminary Staff Assessment (PSA) related to traffic and transportation from the California Coastal Commission and the city of Huntington Beach (TN# 212797, **212437**). [bold added for emphasis]

For this reason, staff does not identify the city’s letter in the reference list.

City comment: *The FSA concludes no additional analysis is required for the amended HBEP, that the 2014 environmental analysis and conclusions are adequate. Public Works staff believes that supplemental environmental analysis is required for examining Traffic and Transportation related impacts related to the Magnolia Street/Banning Avenue intersection reconfiguration, cumulative project traffic analysis, and that the responses to the Preliminary Staff Assessment (PSA) comments from City of Huntington Beach provided in the FSA are insufficient. Please refer to the following items.*

Response: The Magnolia Street/Banning Avenue intersection reconfiguration is considered part of the whole of the proposed HBEP for CEQA purposes. As such, the potential environmental impacts to traffic and transportation operations related to the proposed intersection reconfiguration are fully considered in the FSA. Specifically, staff continues to recommend the existing Condition of Certification **TRANS-4** to ensure the project owner coordinates with the city of Huntington Beach prior to constructing any improvements to the Magnolia/Banning intersection. Staff is also recommending a new Condition of Certification, **TRANS-8,** which would require the project owner to provide to the city of Huntington Beach for review and approval engineering drawings/plans for the design and configuration of the Magnolia/Banning intersection.

Responses to the city's comments related to the insufficiency of analyzing cumulative impacts and previous responses to comments on the PSA are provided in the responses below.

As identified on page 4.10-4 of the PSA, implementation of the amended HBEP would result in fewer construction trips than the licensed HBEP. The proposed amended HBEP is estimated to generate 638 daily one-way trips and 312 peak hour trips as compared to the licensed HBEP which was estimated to generate 734 daily trips and 343 peak hour trips. A new analysis of Magnolia Street/Banning Avenue intersection operations during construction (with project conditions) continues to not be necessary for the amended HBEP because the amended project would not increase the number of trips.

However, the FSA fully analyzes operating conditions of Magnolia Street between Garfield Avenue and Yorktown Avenue and intersections nearest the project site. As discussed under the section Construction Traffic Generation (pages 4.10-4 and 4.10-5 of the FSA) and shown in **Traffic and Transportation Table 1** and **Table 2**, the intersections currently operate at LOS A and are estimated to have sufficient capacity to accommodate the increase in project-related trips during both peak hours. This conclusion is based on the minimal increase of traffic along Magnolia Street (3 percent of average annual daily volume) that would occur during construction. Increased traffic generated during construction of the proposed amended HBEP would not have the potential to substantially change the existing operating conditions of Magnolia Street (estimated to operate at LOS C) or intersections which currently operate at LOS A.

City comment: *(**TRANS-8**) Adding the project's entrance road to the Magnolia Street/Banning Avenue intersection along with the additional project related trips will reduce the Level-of-Service (LOS) at this location. The FSA indicates no additional examination is needed to the 2014 environmental analysis for Traffic and Transportation related impacts, however, this intersection was not evaluated in the 2014 environmental analysis or in the amended HBEP.*

The proposed Magnolia Street/Banning Avenue intersection reconfiguration is stated to provide two entrance lanes and two exit lanes, however, no analysis was presented to support the need for two ingress and two egress lanes. The number of proposed entrance and exit lanes affects the number of on-street parking removed, the amount of public right-of-way that would be disturbed, and how the intersection will operate in terms of the vehicular movements.

Although the amended HBEP did not include environmental analysis of providing a project driveway at the existing signalized intersection of Magnolia Street/Banning Avenue, Public Works staff will continue to work with the applicant regarding the intersection reconfiguration during the engineering drawings/plans processing.

Response: As identified by the project owner, the proposed project would redesign and reconfigure the existing three-way traffic signal at the Magnolia/Banning intersection to facilitate use of the Plains All American site for construction worker parking and as a construction laydown area. Based on staff's review of the Magnolia Street/Banning Avenue intersection, it is staff's view that the applicant proposes two entrance lanes and two exit lanes to match the existing lane configuration. It is noted that the existing Condition of Certification **TRANS-4** and new Condition of Certification **TRANS-8** would ensure the project owner provides to the city of Huntington Beach for review and approval engineering drawings/plans for the design and configuration of the Magnolia/Banning intersection prior to constructing any improvements.

Related to the number of on-street parking removed as a result of the design and configuration of the Magnolia/Banning intersection, staff is recommending a new Condition of Certification, **TRANS-9,** which requires the project owner to provide replacement parking on a one-to-one basis in conformance with the city of Huntington Beach zoning code. The project owner would achieve this requirement in coordination with city staff as identified in a subsequent comment.

In response to analyzing how the intersection will operate in terms of the vehicular movements, please refer to the response provided for the previous city comment.

City comment: *(**TRANS-8**): The proposed Magnolia Street/Banning Avenue intersection reconfiguration could remove existing coastal zone on-street parking on Magnolia Street. The FSA recognizes the City's requirement to replace any lost on-street parking within walking distance of the displaced parking spaces and proposes to implement Condition of Certification **TRANS-9** to comply with City requirements. However, at that location Public Works staff is not aware of any existing public right-of-way areas within walking distance that could be used for replacement parking. Should parking be displaced due to the intersection reconfiguration Public Works staff could assist the applicant with finding means of replacing the parking.*

Response: If the project owner is unable to comply with the requirements specified in Condition of Certification **TRANS-9,** then the applicant would not be able to implement the proposed Magnolia Street/Banning Avenue intersection reconfiguration and use the All Plains site as a parking/ laydown area. However, staff's review of the intersection identified the west curb of the intersection painted red which identifies no parking allowed. Based on the sections and locations of curbs painted red (no parking allowed) at this intersection, staff believes only one existing coastal zone on-street parking spot would be removed with implementation of the Magnolia Street/Banning Avenue intersection reconfiguration. Staff also envisions the design of the Magnolia Street/ Banning Avenue intersection could accommodate the required replacement parking.

City comment: *Public Works staff disagrees with the assessment of not needing to identify the Poseidon Desalination project in a cumulative project analysis of traffic and transportation impacts. This page suggests that because the Poseidon Desalination project is required to pay "Fair Share Traffic Impact Fee" to fund project related transportation impacts it can be excluded from the cumulative analysis. In a cumulative analysis, regardless of what conditions of approval are assigned individually to projects, all vicinity located projects are to be included to determine what cumulative transportation impacts would result. Due to the lack of supporting analysis and documentation, Public Works staff disagrees with the statement in the FSA that the project's (Poseidon Desalination) incremental effects would not be cumulatively considerable.*

Response: Staff revised the staff assessment to include the Poseidon Desalination project in the FSA. Specifically, staff responded to a city comment on the PSA by stating, " the Poseidon Desalination project was not specifically identified in the analysis of cumulative traffic and transportation impacts. The cumulative analysis has been updated in this FSA to reflect this." The Poseidon Desalination project was never specifically excluded from the cumulative project analysis. Please refer to the Cumulative Impacts analysis provided in the FSA (specifically to page 4.10-6 regarding the Poseidon Desalination project).

City comment: *Public Works staff discussed the pedestrians crossing Newland Street from the three acre proposed construction parking area, however, did not indicate a marked pedestrian crosswalk as the determined crossing treatment (Condition of Certification **TRANS-8**). Rather, Public Works staff discussed the need of a traffic engineering study, compliant with standards and guidelines of the California Manual on Uniform Traffic Control Devices (state's official standards and specifications for all official traffic control devices as mandated by Section 2 1400 of the California Vehicle Code and accepted by the Federal Highway Administration per Title 23, Code of Federal Regulations), to determine what appropriate traffic control device treatment(s) and/or measure(s) that should be implemented to provide for safe and efficient pedestrian travel across Newland Street. City staff will coordinate with the applicant in determining the proper traffic control devices for that activity. Related to that concern, the text on page 4.10-15 should read "pedestrian crossing" rather than "pedestrian crosswalk" which implies the treatment is a marked crosswalk only*.

Response: Staff acknowledges the city's willingness to coordinate with the project owner. Staff has agreed to revise text in Condition of Certification **TRANS-8** to refer to "pedestrian crossing" instead of "pedestrian crosswalk." Please refer to the revisions at the end of this document.

City comment: *Due to the City's plan review processing timelines, submittals of engineering drawings of at least 30 days prior to construction is insufficient time for Public Works staff to review, comment, and final (approve) plans. Public Works staff recommends submittal of engineering drawings/plans a minimum of six months prior to the scheduled begin of construction.*

The condition should read that the engineering plans for the intersection reconfiguration and pedestrian crossing are to be "reviewed and approved" rather than "review and comment" by the City of Huntington Beach Public Works Department. This would be consistent with the Huntington Beach's Encroachment Permit requirements and statements in the FSA, for example on page 4.10-8, which states that engineering plans shall be reviewed and approved prior to construction.

Response: Staff has agreed to revise text in Condition of Certification **TRANS-8** to provide additional time for the city to review and comment by requiring the project owner to submit engineering plan/drawings three months prior to construction of the intersection reconfiguration and prior to use of the Newland Street construction parking area.

As related to the requested language “reviewed and approved,” staff made further revisions to Condition of Certification **TRANS-8** after preparing responses to city’s comments on the PSA provided on page 4.10-8 of the FSA. Staff made further revisions with the recognition of the need for local expertise (e.g., city of Huntington Beach Public Works Department staff). For this reason, staff recommends keeping Condition of Certification **TRANS-4** which requires the project owner or its contractor(s) to obtain all required encroachment permits including those from the city of Huntington Beach. Although Condition of Certification **TRANS-8** is written in such a way that the CBO has the authority to approve any engineering plan/drawings, and the city has the ability to review and comment, if the project owner is unable to comply with the requirements specified in Condition of Certification **TRANS-4** then the applicant would not be able to implement the proposed Magnolia Street/Banning Avenue intersection reconfiguration. The following is staff’s proposed changes to **TRANS-8** (based on staff’s FSA) to respond to the city’s request. Text to be removed is ~~struck through~~ and new text is shown as **bold** and double underlined.

TRANS-8 CONSTRUCTION WORKER PARKING/CONSTRUCTION LAYDOWN ACCESS

The project owner shall provide the engineering plan/drawings for the design and reconfiguration of the Magnolia/Banning intersection (signal and street striping/signage), including the grading and civil engineering to construct a two-lane entrance road into the Plains former oil storage site to the city of Huntington Beach Public Works Department for review and comment, and to the CBO for review and approval.

The project owner shall provide the engineering plan/drawings for the design and configuration of entrances and a pedestrian ~~crosswalk~~ crossing for the Newland Street construction parking area to the city of Huntington Beach Public Works Department for review and comment, and to the CBO for review and approval.

Verification: **At least ~~30 days~~ 3 months prior to construction of the intersection reconfiguration, the project owner shall provide the engineering plan/drawings for the design and reconfiguration of the Magnolia/Banning intersection and entrance road into the Plains site and the design and configuration of entrances to the City of Huntington Beach Public Works Department for review and comment and to the CBO for review and approval.**

At least ~~30 days~~ 3 months prior to use of the Newland Street construction parking area, the project owner shall provide the engineering plan/drawings for the design and reconfiguration of the pedestrian ~~crosswalk~~ crossing to the City of Huntington Beach Public Works Department for review and comment and to the CBO for review and approval.

WATER RESOURCES

Supplemental Testimony of Mike Conway

This testimony supplements and clarifies the information in the Final Staff Assessment Part 1. Staff has received additional comments from the city of Huntington Beach and staff has provided responses to these comments below.

At the November 14, 2016, Pre-Hearing Conference, the Committee identified topics requiring additional staff responses in the FSA Part 2 or supplemental testimony to FSA Part 1. The committee topics included whether Water Code section 10910, subdivision (h) applies to Huntington Beach Energy Project's (HBEP) Water Supply Assessment (WSA).

The referred code section is provided below.

Water Code section 10910, subdivision (h):

(h) Notwithstanding any other provision of this part, if a project has been the subject of a water supply assessment that complies with the requirements of this part, no additional water supply assessment shall be required for subsequent projects that were part of a larger project for which a water supply assessment was completed and that has complied with the requirements of this part and for which the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), has concluded that its water supplies are sufficient to meet the projected water demand associated with the proposed project, in addition to the existing and planned future uses, including, but not limited to, agricultural and industrial uses, unless one or more of the following changes occurs:

(1) Changes in the project that result in a substantial increase in water demand for the project.

(2) Changes in the circumstances or conditions substantially affecting the ability of the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), to provide a sufficient supply of water for the project.

(3) Significant new information becomes available which was not known and could not have been known at the time when the assessment was prepared.

STAFF RESPONSE

Staff's understanding is that Water Code section 10910 subdivision (h) does apply to the Licensed HBEP WSA and that a new WSA is not needed for the HBEP PTA. Staff's PSA and FSA for the HBEP PTA documented that there were changes in circumstances since the Commission Decision that warranted re-visiting and updating the WSA data. Staff requested input from the city of Huntington Beach, which replied that the HBEP PTA did not require a WSA. Staff concurred and also conveyed the information provided by the city in the PSA and FSA. Staff's intent is to provide the information to the committee, so that it may conduct any analysis it thinks relevant or applicable.

In the FSA published October 17, 2016, staff used a robust and methodical approach to examine HBEP PTA's water usage habits and to estimate what would be used by a 500-dwelling-unit development. This was only to determine, out of an abundance of caution, whether the PTA was a project requiring a WSA, regardless of Water Code section 10910, subdivision (h). Staff did not however prepare a WSA, nor would the information provided by staff stand alone as a WSA. If staff were to prepare a WSA, it would provide a thorough description of all sources of supply to the city as well as contractual obligations and contingent supplies and demands. The extensive network of the city's water supply chain is complex and likely subject to changing restrictions during California's drought, all of which should be evaluated alongside the most current information if a WSA were needed. The information provided by staff provides a more through methodology for conducting an assessment of what constitutes a project under water code section 10910.

WORKER SAFETY AND FIRE PROTECTION

Supplemental Testimony of Brett Fooks, PE and Geoff Lesh, PE

This testimony supplements and clarifies the information in the Final Staff Assessment Part 1. Staff has received additional comments from the City of Huntington Beach and staff has provided responses to these comments below.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Comment: *Page 3-1: The FSA [Part 1] states that the Plains All American Site will be used as a parking lot and staging area for the AES [HBEP] construction activity. The plans also indicate that a new intersection will be created at Magnolia and Banning. The HBFD will require to review and approve a plan showing the location of the items listed below prior to the issuance of construction permits by the Chief Building Official:*

a. *Parking Locations*
b. *Staging Locations*
c. *Fire Department Access (Compliant with City Specification #401)*
d. *Fire Hydrant Locations (**CHPWD 2016e**)*

Response: Staff concurs that the project owner would be required to comply with all local laws, ordinances, regulations and standards (LORS). To ensure compliance with local LORS, Conditions of Certification **WORKER SAFETY-6** and **-7** would require that the project owner submit to the Huntington Beach Fire Department for review and comment, and to the Energy Commission compliance project manager for review and approval, all plans relating to fire protection and emergency response (including access for emergency response vehicles) for both the main project site and any jurisdictional appurtenant sites, including the Plains All American site.

Comment: *The HBFD concurs with the FSA [Part 1] statement on 4.14-7, in that the applicant shall provide the HBFD with the proposed site access plan. The access plans shall show compliance with City Specification #401 and be provided with the items listed below from the FSA. The HBFD will require review of the final fire department access lane prior to issuance of construction permits by the Chief Building Official. (**CHPWD 2016e**)*

Response: See staff response to first comment above.

REFERENCES

CHPWD 2016e - Huntington Beach Department of Community Development (TN 214618). Comments regarding final Staff Assessment Part 1, dated December 1, 2016. Submitted to CEC/Docket Unit on December 2, 2016.

VISUAL RESOURCES

Supplemental Testimony of Jeanine Hinde

Following publication of the final staff assessment (FSA) for Part 1 of the HBEP Petition to Amend (PTA) (TN #214025), the project owner submitted opening testimony in the PTA proceeding (TN #214211), which includes a request to extend the timing to complete the visual enhancement and screening elements for the combined-cycle gas turbine (CCGT) units. The project owner's proposed timing change is under the verification for Condition of Certification **VIS-1**, *Visual Screening and Enhancement Plan for Project Structures – Project Operation*. The requested revisions to verification for **VIS-1** are based on this statement in the project owner's opening testimony (TN #214211):

> *Project Owner has initiated preliminary planning for the project and determined that one of the screen walls will need to be placed across the Unit 1 and 2 foundation. This placement will require demolition of Units 1 and 2 prior to full implementation of the plan elements that screen the CCGT. It is, therefore, not possible to implement the CCGT screening elements within 12 months of commercial operation of the CCGT.*

Staff subsequently filed supplemental testimony agreeing to the project owner's proposed change and including minor edits to verification for **VIS-1** (TN #214358). The project owner's prehearing conference statement acknowledges agreement between staff and the project owner on the timing changes under verification for **VIS-1** (TN #214446). Staff's prehearing conference statement followed shortly thereafter (TN #214452), which shows the **VIS-1** verification revisions but inadvertently omits a phrase that was part of the previous version.

To continue the steps in the series of filings on the HBEP PTA and ensure the accuracy of the **Visual Resources** conditions of certification, staff reproduces the changes to **VIS-1** verification that were agreed to between the project owner and staff. The paragraph with these changes is in the middle of page 4.12-24 of the FSA Part 1. This supplemental information does not result in changes to any of the other conditions of certification presented in the **Visual Resources** section of the FSA Part 1.

VIS-1 VISUAL SCREENING AND ENHANCEMENT PLAN FOR PROJECT STRUCTURES – PROJECT OPERATION

<u>Verification:</u> ~~The project owner shall schedule periodic site visits with the CPM to view progress on implementing the Plan. At a minimum, site visits shall be scheduled within 30 calendar days of commercial operation of Power Block 1 and again within 30 calendar days of commercial operation of Power Block 2.~~ **<u>The Plan elements pertaining to screening and enhancement of the CCGT units, including the easternmost and middle screens,</u>** ~~The Plan~~ shall be ~~fully~~ implemented within **<u>12 months of</u>** ~~90 calendar days of completing demolition of the Huntington Beach Generating Station Units 1 and 2~~ **<u>completing demolition of the HBGS Units 1 and 2. The Plan elements pertaining to screening and enhancement of the simple-</u>**

cycle gas turbine (SCGT) units shall be implemented within 12 months of beginning commercial operation of the SCGT units.

RESPONSES TO CITY OF HUNTINGTON BEACH COMMENTS

On December 1, 2016, the City of Huntington Beach (city) submitted comments (TN #214618) on the FSA Part 1 for the HBEP PTA. The city's comments pertain to the timing for completing implementation of the conditions of certification to screen and enhance the project site. In addition to **VIS-1**, the city submitted comments on timing for Condition of Certification **VIS-2**, *Perimeter Screening and On-site Landscape and Irrigation Plan – Project Operation*.

The city's comment #11 on **Visual Resources** agrees with staff's statements on page 4.12-17 of the FSA that architectural screens on the site must be accounted for during project planning and design to ensure they will fit on the site, adequately screen project structures, and avoid conflicts with emergency access.

The city's comment #12 opposes the delayed timing for implementing the visual screening plans (**VIS-1** and **VIS-2**), stating that "it is common practice to complete all conditions of approval and all project components prior to operation of the proposed use."

As shown in **Visual Resources Figure 10** in the FSA Part 1, the area between the proposed CCGT units, fire access lanes, and the proposed acoustical wall on the eastern portion of the project site is constrained. Demolition of HBGS Units 1 and 2 will occur after the start of commercial operation of the amended project's CCGT units, which means that the architectural sphere walls cannot be installed until this phase in the demolition and construction timeline is finished. Given the large scale of the architectural sphere walls, staff considers a 1-year time frame to complete implementation of **VIS-1** to be reasonable.

In addition to the architectural screens (sphere walls), **VIS-1** requires that the surfaces of publicly visible power plant structures be treated to coordinate visually with the architectural screens. Structures requiring surface treatments include, *but are not limited to*, the exhaust stacks, air cooled condenser, and the 50-foot-tall acoustical wall. The surfaces of power plant structures will have been treated according to an approved **VIS-1** Plan, which will be completed according to a schedule that must be included in the Plan. Surface treatments of power plant structures will be completed during manufacture of those structures and/or during construction and before commercial operation of the CCGT units. This means that progress will have been made to implement the **VIS-1** Plan when the CCGT units become operational.

The city's comment #12 (TN #214618) opposes the delay in completing site landscaping under Condition of Certification **VIS-2**, which includes site perimeter landscape plantings, irrigation, and an 8-foot-tall decorative masonry wall along portions of the site boundary. The project owner is required to complete **VIS-2** within 270 calendar days (9 months) of beginning commercial operation of the CCGT units. The FSA Part 1 includes Condition of Certification **VIS-3**, *Long-term Construction Screening, Landscape Protection, and Site Restoration Plan – Project Demolition, Construction,* *and Commissioning*. **VIS-3** requires the project owner to complete site restoration activities (i.e., restore disturbed areas to their original or better condition) within 180 calendar days (6 months) of beginning commercial operation of the CCGT units. The work to complete **VIS-2** and **VIS-3** will overlap during the first 6 months following commercial operation of the CCGT units, but will allow the project owner an additional 3 months to complete the **VIS-2** site landscape elements. Staff acknowledges the city's opposition to delaying site landscaping, but given the large project site and the schedule overlap between site restoration and landscape installation, staff considers the 9-month time frame to complete **VIS-2** to be reasonable.

The City of Huntington Beach Fire Department (HBFD) submitted comments on the FSA Part 1 (TN #214618) identifying potential conflicts between placement of the architectural screens and emergency access to existing and new power plant facilities. HBFD comment #4 on **Visual Resources** agrees with staff's statements on page 4.12-17 of the FSA that architectural screens on the site must not travel over fire department access lanes. HBFD comment #5 refers to **Visual Resources Figure 10**, stating that the currently proposed placement of the architectural screens is unacceptable and would block portions of the power plant facilities from firefighting operations. Condition of Certification **VIS-1** requires the project owner to submit a *Preliminary Visual Screening and Enhancement Plan for Project Structures* that will include information on how the architectural screens will comply with city requirements for fire protection access. The preliminary **VIS-1** plan must be submitted to the compliance project manager (CPM) at least 60 calendar days prior to the start of construction. A total of seven copies of the preliminary plan must be submitted to the city, including a copy for the HBFD. As stated under verification for **VIS-1**, the city shall be allowed 30 calendar days following receipt of the plan to submit comments to the project owner and the CPM.