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Organization:	Stoel Rives, LLP
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From: Salamy, Jerry/SAC
Sent: Tuesday, October 13, 2015 2:43 PM
To: Andrew Lee <ALee@aqmd.gov>
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Subject: Amended Huntington Beach Energy Project Air Permit Completeness Response (Facility ID 115389)

Andrew,

Attached is AES's response to those items identified as incomplete in your September 30, 2015 Amended Huntington Beach Energy Project completeness determination letter. This response includes the following items.

- An updated best available control technology assessment for both criteria and greenhouse gases
- The permit unit, control device, emission estimates, and stack parameters presented in a tabular format
- A detailed compliance assessment demonstrating compliance with applicable federal/state/local air quality rules and regulations
- Details start-up emissions for the combined cycle generating unit
- The auxiliary boiler's selective catalytic reduction system manufacturer, model, and size details
- Facility operating parameters, including the number/type of start-up and shutdowns per day, month, and year.
- AES Corporation's certification that all major California sources owned and operated by AES are in compliance with applicable air quality regulations
- Decommissioning plan details for Huntington Beach Generating Station Units 1 and 2 and Redondo Beach Generating Station Unit 7.

A hard copy of the attached document will be delivered to your attention. If you have any questions, please let me know.

Thanks,

Jerry Salamy
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AES Huntington Beach

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October 12, 2015

Mr. Andrew Lee, P.E.
Senior Engineering Manager
Engineering and Compliance
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-4178

Subject: Huntington Beach Energy Project Permit Application (Facility ID 115389)

Dear Mr. Lee:

AES Huntington Beach, LLC (AES) is submitting this letter in response to the South Coast Air Quality Management District's (SCAQMD) September 30, 2015, request for additional information pertaining to the Huntington Beach Energy Project's (HBEP) air permit application. This letter presents AES's responses to the requested information.

1) Provide a Criteria Pollutant and GHG Best Available Control Technology Assessment

Response: Attachment 1 presents a revised criteria pollutant and greenhouse gas (GHG) Best Available Control Technology (BACT) assessment.

2) Provide Data in Tabular Format

Response: Attachment 2 provides a description of the HBEP with equipment and emissions data presented in a tabular format consistent with the format of the HBEP Final Determination of Compliance. Appendix A to Attachment 2 presents the air quality impacts expected from operation of the HBEP.

3) Provide a Detailed Assessment of How the Turbines will Comply with Applicable Federal/State/Local Rules and Regulations

Response: Attachment 2 presents a detailed assessment of how the HBEP complies with applicable federal, state, and local rules and regulations.

4) Provide Detailed Startup Emissions for the Combined-cycle Generating Unit

Response: Attachment 3 presents the combined-cycle power block startup emissions in a format consistent with the simple-cycle power block startup emissions data.

5) Provide Manufacturer Name, Type, and Size Information for the Auxiliary Boiler Selective Catalytic Reduction System

Response: Attachment 2, Section 2.4 [Air Pollution Control (APC) Equipment] presents the manufacturer name, type, and size information for the auxiliary boiler selective catalytic reduction system.

6) Provide the Proposed Maximum Number of Daily Startups for Each Turbine

Response: Each turbine is assumed to start up twice per day, or 62 startups per month. Attachment 2 presents a detailed description of the number and type of daily, monthly, and annual startup and shutdown events for each turbine type.

7) Provide a Statement Certifying that All Major California Sources Owned or Operated by AES Corporation are in Compliance with Applicable Air Quality Regulations

Response:

> I, Stephen O'Kane, as a corporate office of AES Huntington Beach, LLC, certify that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by AES in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act.

8) Provide a Decommissioning Plan for Huntington Beach Generating Station Units 1 and 2 and Redondo Beach Generating Station Unit 7

Response: AES will submit a retirement plan to the District for AES Huntington Beach Generating Station Units 1 and 2 and Redondo Beach Generating Station Unit 7 to demonstrate compliance with SCAQMD Rule 1304(a)(2), subsequent to the approval of the HBEP license amendment by the California Energy Commission (CEC) and prior to the issuance of a Permit to Construct from the SCAQMD. AES has successfully retired other units at the Huntington Beach Generating Station to the SCAQMD's satisfaction and does not believe that actual retirement plans for these units should be required in order to complete the preliminary or final determination of compliance for HBEP.

If you require further information, please do not hesitate contacting me at 562-493-7840.

Sincerely,

SOKane

Stephen O'Kane
Manager
AES Huntington Beach, LLC
Attachments

cc: Robert Mason/CH2M HILL
Jennifer Didlo/AES
Melissa Foster/Stoel Rives
Jerry Salamy/CH2M HILL

Attachment 1
Best Available Control Technology Determination for Huntington Beach Energy Project

BACT Determination for the Huntington Beach Energy Project

Prepared for

AES Southland Development, LLC

Submitted to

South Coast Air Quality Management District
EPA Region IX

October 2015

CH2MHILL®

Contents

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Acronyms and Abbreviations

°F	degree(s) Fahrenheit
AES	AES Southland Development, LLC
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
Btu/kWh	British thermal units per kilowatt-hour
CARB	California Air Resources Board
CCS	carbon capture and storage
CEC	California Energy Commission
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
CPV	Competitive Power Ventures
CTG	combustion turbine generator
DLN	dry low NO_x
DOE	U.S. Department of Energy
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
GE	General Electric
GHG Tailoring Rule	Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule
GHG	greenhouse gases
GJ	gigajoule(s)
H_2	hydrogen
HBEP	Huntington Beach Energy Project
HFC	hydrofluorocarbon
hp	horsepower
HRSG	heat recovery steam generator
IPCC	Intergovernmental Panel on Climate Change
kg	kilogram(s)
LAER	Lowest Achievable Emission Rate
lb	pound(s)
lb/event	pound(s) per event
lb/hr	pound(s) per hour
lb/MWh	pound(s) per megawatt-hour
Mandatory Reporting Rule	EPA Final Mandatory Reporting of Greenhouse Gases Rule
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
$MTCO_2$/MWh	metric ton(s) of carbon dioxide per megawatt-hour
MW	megawatt(s)
MWh	megawatt-hour(s)
N_2	nitrogen
N_2O	nitrous oxide
N/A	not applicable
NATCARB	National Carbon Sequestration Database and Geographic Information System
NETL	National Energy Technology Laboratory
NGCC	natural gas combined-cycle
NO	nitric oxide

NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NSR	New Source Review
O_2	oxygen
OTC	once-through cooling
PFC	perfluorocarbons
PM	particulate matter
PM_{10}	and particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
ppm	part(s) per million
ppmv	part(s) per million by volume
ppmvd	part(s) per million dry volume
PSA	pressure swing adsorption
PSD	Prevention of Significant Deterioration
psig	pound(s) of force per square inch gauge
PTE	Potential to Emit
RACT	Retrofit Available Control Technology
RPS	Renewable Portfolio Standard
SCAQMD	South Coast Air Quality Management District
scf	standard cubic feet
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SoCalCarb	Southern California Carbon Sequestration Research Consortium
SoCalGas	Southern California Gas
SO_x	sulfur oxides
STG	steam turbine generator
tpy	ton(s) per year
VOC	volatile organic compound
WestCarb	West Coast Regional Carbon Sequestration Partnership

SECTION 1
Project Description

1.1 Project Overview

AES Southland Development, LLC (AES) proposes to construct the Huntington Beach Energy Project (HBEP or Project) at the existing AES Huntington Beach Generating Station site at 21730 Newland Street, Huntington Beach, California 92646. The HBEP will consist of two power blocks, with one power block consisting of a two-on-one combined-cycle power block with a capacity of 644 megawatts (MW) and a second power block consisting of two simple-cycle gas turbines with a capacity of 200 MW.

The combined-cycle power block will consist of two General Electric (GE) Frame 7FA.05 combustion turbine generators (CTG), one steam turbine generator (STG), an auxiliary boiler, and an air-cooled condenser. Each CTG will be equipped with an unfired heat recovery steam generator (HRSG). The CTGs will use dry low oxides of nitrogen (NO_x) (DLN) burners and selective catalytic reduction (SCR) to limit NO_x emissions to 2 parts per million by volume (ppmv). Emissions of carbon monoxide (CO) will be limited to 2 ppmv and volatile organic compounds (VOC) to 2 ppmv through the use of best combustion practices and an oxidation catalyst. Best combustion practices and burning pipeline-quality natural gas will minimize emissions of the remaining pollutants.

The simple-cycle power block will consist of two GE LMS-100PB CTGs and an air-cooled fin-fan cooler. The CTGs will use DLN burners and SCR to limit NO_x emissions to 2.5 ppmv. Emissions of CO will be limited to 4 ppmv and VOC to 2 ppmv through the use of best combustion practices and an oxidation catalyst. Best combustion practices and burning pipeline-quality natural gas will minimize emissions of the remaining pollutants.

The auxiliary boiler will be a natural-gas-fired unit, including flue gas recirculation and SCR to reduce NO_x and CO emissions to 5 ppmv and 50 ppmv, respectively. The auxiliary boiler will be used to reduce the startup duration of the combined-cycle power block, thereby reducing air emissions.

The HBEP will retain the use of the two existing 275-horsepower (hp) diesel-fired emergency fire water pumps installed during the Huntington Beach Generating Station Units 3 and 4 retooling project in 2001. Because the existing fire water pumps are permitted sources by the South Coast Air Quality Management District (SCAQMD) and are neither being modified nor will their operating profile change, AES has not included the fire pumps in the best available control technology (BACT) analysis for the HBEP.

Authorization for the construction and operation of the HBEP will be through the California Energy Commission (CEC) licensing process and the SCAQMD New Source Review/Prevention of Significant Deterioration (NSR/PSD) permitting process. Because the HBEP includes the use of steam to generate electricity, the Project is also categorized as one of the 28 major PSD source categories (40 Code of Federal Regulations [CFR] 52.21(b)(1)(i)). Therefore, the Project is subject to PSD permitting requirements if the Potential to Emit (PTE) from the Amended Project exceeds 100 tons per year (tpy) for any regulated pollutant.

The Project PTE is expected to exceed the major source threshold for at least one of the PSD-regulated pollutants. Therefore, the Amended Project will be considered a major stationary source in accordance with PSD regulations. The SCAQMD has also been delegated partial PSD permitting authority.[1] Therefore, the PSD BACT analysis is being submitted to the SCAQMD as part of the permitting process.

1.2 Project Objectives

The HBEP's key design objective is to provide up to 844 MW of environmentally responsible, cost-effective, operationally flexible, and efficient generating capacity to the western Los Angeles Basin Local Reliability Area in general, and specifically to the coastal area of Orange County. The Amended Project would serve local area reliability needs, southern California energy demand, and provide controllable generation to allow the integration

[1] http://www.epa.gov/region09/air/permit/pdf/full-scagmd-psd-delegation.pdf

of the ever-increasing contribution of intermittent renewable energy into the electrical grid. The Amended Project will displace older and less efficient generation in southern California, and has been designed to start and stop very quickly and be able to quickly ramp up and down through a wide range of generating capacity. As more renewable electrical resources are brought on line as a result of electric utilities meeting California's Renewable Portfolio Standard, projects strategically located within load centers and designed for fast starts and ramp-up and down capability, such as the HBEP, will be critical in supporting both local electrical reliability and grid stability.

The Amended Project objectives are also contingent on the use of the offset exemption contained within SCAQMD's Rule 1304(a)(2), which allows for the replacement of older, less-efficient electric utility steam boilers with specific new generation technologies on a MW-to-MW basis (that is, the replacement MW are equal to or less than the MW from the electric utility steam boilers). The offset exemption in Rule 1304(a)(2) requires the electric utility steam boiler to be replaced with one of several specific technologies, including the combined-cycle configuration proposed for the Amended HBEP.

The HBEP was designed to address the local capacity requirements within the Los Angeles Basin with the following objectives:

- Provide the most efficient, reliable, and predictable power supply available by using natural-gas-fired combustion turbine technology to replace the once-through cooling (OTC) generation, support the local capacity requirements of southern California's Western Los Angeles Basin, and be consistent with SCAQMD Rule 1304(a)(2).
- Develop an 844-MW project that provides efficient operational flexibility with rapid-start and steep ramping capability (30 percent per minute) to allow for the efficient integration of renewable energy sources into the California electrical grid with competitive electrical generation pricing.
- Reuse existing electrical, water, wastewater, and natural gas infrastructure and land to the extent possible to minimize terrestrial resource and environmental justice impacts by developing on a brownfield site.
- Secure a sufficient-sized site to maintain existing generating capacity to meet regional grid reliability requirements during the development of the project.
- Site the project to serve the Western Los Angeles Basin load center without constructing new transmission facilities.
- Assist the State of California in developing increased local generation projects, thus reducing dependence on imported power.
- Site the project on property that has industrial land use designation with consistent zoning.
- Ensure potential environmental impacts can be avoided, eliminated, or mitigated to a less-than-significant level.

Locating the Amended Project on an existing power plant site avoids the need to construct new linear facilities, including gas and water supply lines, discharge lines, and transmission interconnections. This reduces potential offsite environmental impacts, and the cost of construction. The proposed HBEP site meets all project siting objectives.

The HBEP will provide power to the grid to help meet the need for electricity and to help replace dirtier, less efficient fossil fuel generation resources. The HBEP will enhance the reliability of the state's electrical system by providing power generation near the centers of electrical demand and providing fast response generating capacity to enable increased renewable energy development. Additionally, as demonstrated by the analyses contained in the CEC licensing documentation, the Amended Project would not result in any significant environmental impacts.

SECTION 2

Criteria Pollutant BACT Analysis

Based on SCAQMD's BACT definition and major source thresholds (SCAQMD Rules 1302 and 1303), a BACT analysis is required for the uncontrolled emissions of NO_x, VOC, CO, sulfur oxides (SO_x), and particulate matter less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). Also, the U.S. Environmental Protection Agency (EPA) requires a BACT analysis for the emissions of greenhouse gases (GHGs) as part of the PSD permit application required under the EPA Tailoring Rule. The GHG BACT analysis is included in the following section.

AES plans to rely on the response characteristics of the GE CTGs and auxiliary boiler to provide a wide range of efficient, operationally flexible, fast-start, fast-ramping capacity to allow for the efficient integration of renewable energy sources into the California electrical grid. Table 2 -1 presents the proposed permit levels for the combined and simple-cycle CTGs.

TABLE 2-1

Maximum Pollutant Emission Rates for Operation of the HBEP

Pollutant	Emission Limits (at 15% O_2)		
	One GE 7FA.05 [a]	One GE LMS-100PB [b]	One Auxiliary Boiler [c]
VOC	2 ppmv (averaged over 1-hour)	2 ppmv (averaged over 1-hour)	0.28 lb/hr
CO	2 ppmv (averaged over 1-hour)	4 ppmv (averaged over 1-hour)	50 ppmv (averaged over 1-hour)
NO_x	2 ppmv (averaged over 1-hour)	2.5 ppmv (averaged over 1-hour)	5 ppmv (averaged over 1-hour)
SO_x	<0.75 grain of sulfur per 100 dry standard cubic feet of natural gas		0.048 lb/hr
$PM_{10/2.5}$	8.50 lb/hr	6.24 lb/hr	0.30 lb/hr
Ammonia	5 ppmv	5 ppmv	5 ppmv
GHG [d]	766 lb CO_2/MWh (Net)	1,161 lb CO_2/MWh (Net)	N/A

[a] Maximum values are for each turbine at an ambient temperature of 32°F and excludes startups and shutdowns.

[b] Maximum values are for each turbine at an ambient temperature of 65.8°F and excludes startups and shutdowns.

[c] Maximum hourly emission rates assume 100 percent load.

[d] Includes an 8 percent degradation.

Notes:

CO_2 = carbon dioxide

°F = degrees Fahrenheit

N/A = not applicable (i.e., BACT analysis not required)

O_2 = oxygen

lb/hr = pound(s) per hour

lb/MWh = pound(s) per megawatt-hour

The following discussion presents an assessment of the BACT for the HBEP and includes the following components:

- Outline of the methodology used to conduct the criteria pollutant BACT analyses
- Discussion of the available technology options for controlling NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and SO_x emissions
- Presentation of the proposed BACT emission levels identified for the HBEP

2.1 Methodology for Evaluating the Criteria Pollutant BACT Emission Levels

The NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and SO_x BACT analysis for the HBEP is based on EPA's top-down analysis method. The following top-down analysis steps are listed in EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate the most-effective controls, and document the results
- Step 5: Select the BACT

As part of the control technology ranking step (Step 3), emission limits for other recently permitted natural-gas-fired combustion turbines were compiled based on a search of the various federal, state, and local BACT, Retrofit Available Control Technology (RACT), and Lowest Achievable Emission Rate (LAER) databases. The following databases were included in the search:

- **EPA RACT/BACT/LAER Clearinghouse (EPA, 2015)**
  - Search included the NO_x, CO, VOC, particulate matter (PM), and sulfur dioxide (SO_2) BACT/LAER determinations for combined-cycle and simple-cycle combustion turbines with permit dates between 2001 and September 2015.
- **California Air Pollution Control Officers Association/California Air Resources Board (CARB) BACT Clearinghouse (CARB, 2015)**
  - Search included the BACT determinations listed in CARB's BACT clearinghouse for combined-cycle and simple-cycle turbines from all California air districts.
- **Local Air Pollution Control Districts BACT Guidelines/Clearinghouses:**
  - **SCAQMD BACT Guidelines (SCAQMD, 2015)**
    - Search included the BACT determinations for combined-cycle and simple-cycle gas turbines listed in SCAQMD BACT Guidelines for major sources.
  - **Bay Area Air Quality Management District (BAAQMD) BACT/Toxics BACT Guidelines (BAAQMD, 2015)**
    - Search included the BACT determinations for combined-cycle and simple-cycle turbines equal to or greater than 40 MW in Section 2, Combustion Sources, in the BAAQMD BACT Guidelines.
  - **San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse (SJVAPCD, 2015)**
    - Search included the BACT determinations listed under the SJVAPCD BACT Guideline Section 3.4.2 (combined- and simple-cycle, uniform-load gas turbines greater than 50 MW)
- **BACT Analyses for Recently Permitted Combustion Turbine CEC Projects (CEC, 2015)**
  - Review included the BACT analysis for the Pio Pico, GWF Tracy, Hanford, and Henrietta projects, the Oakley Generating Station Project, the Mariposa Energy Project, the Russell City Energy Center, the Los Esteros Critical Energy Facility – Phase 1 and Phase 2, the Palmdale Hybrid Power Project, the El Segundo Power Project, the Carlsbad Power Project, and the Watson Cogeneration and Electric Reliability Project.

The natural-gas-fired combustion turbine permit emission limits for each of the BACT pollutants at other recently permitted facilities were then compared to the proposed emission limits for the HBEP, as set forth in Table 2-1. If the emission limits at other facilities were less than the values in Table 2-1, additional research was conducted to find which turbine technology had been selected and whether the facilities had been constructed (Step 3). If it could be demonstrated that other units with lower emission rates either had not yet been built or used a different turbine technology than that selected for the HBEP, the proposed emission limits for the HBEP were determined to be BACT (Step 5).

2.2 Criteria Pollutant BACT Analysis

2.2.1 NO_x

NO_x is a byproduct of the combustion of an air-and-fuel mixture in a high-temperature environment. NO_x is formed when the heat of combustion causes the nitrogen (N_2) molecules in the combustion air to dissociate into individual N_2 atoms, which then combine with oxygen (O_2) atoms to form nitric oxide (NO) and nitrogen dioxide (NO_2). The principal form of nitrogen oxide produced during turbine combustion is NO, but NO reacts quickly to form NO_2, creating a mixture of NO and NO_2 commonly called NO_x.

2.2.1.1 Identification of Combustion Turbine NO_x Emissions Control Technologies – Step 1

Several combustion and post-combustion technologies are available for controlling turbine NO_x emissions. Combustion controls minimize the amount of NO_x created during the combustion process, and post-combustion controls remove NO_x from the exhaust stream after the combustion has occurred. Following are the three basic strategies for reducing NO_x during the combustion process:

1. Reduction of the peak combustion temperature
2. Reduction in the amount of time the air and fuel mixture is exposed to the high combustion temperature
3. Reduction in the O_2 level in the primary combustion zone

Following is a discussion of the potential control technologies for combined-cycle and simple-cycle combustion turbines:

NO_x Combustion Control Technologies. The two combustion controls for combustion turbines are (1) the use of water or steam injection, and (2) DLN combustors, which include lean premix and catalytic combustors.

Water or Steam Injection. The injection of water or steam into the combustor of a gas turbine quenches the flame and absorbs heat, reducing the combustion temperature. This temperature reduction reduces the formation of thermal NO_x. Water or steam injection also allows more fuel to be burned without overheating critical turbine parts, increasing the combustion turbine maximum power output. Combined with a post-combustion control technology, water or injection can achieve NO_x emission levels of 25 part(s) per million dry volume (ppmvd) at 15 percent O_2, but with the added economic, energy, and environmental expense of using water.

DLN Combustors. Conventional combustors are diffusion-controlled. The fuel and air are injected separately, with combustion occurring at the stoichiometric interfaces. This method of combustion results in combustion "hot spots," which produce higher levels of NO_x. The lean premix and catalytic technologies are two types of DLN combustors that are available alternatives to the conventional combustors to reduce NO_x combustion "hot spots."

In the lean premix combustor, which is the most popular DLN combustor available, the combustors reduce the formation of thermal NO_x through the following: (1) using excess air to reduce the flame temperature (i.e., lean combustion); (2) reducing combustor residence time to limit exposure in a high-temperature environment; (3) mixing fuel and air in an initial "pre-combustion" stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) achieving two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of O_2 available to combine with N_2 and then a secondary lean burn-stage to complete combustion in a cooler environment. Lean premix combustors have only been developed for gas-fired turbines. The more-advanced designs are capable of achieving a 70- to 90 percent NO_x reduction with a vendor-guaranteed NO_x concentration of 9 to 25 ppmvd.

Catalytic combustors use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature to reduce thermal NO_x formation. The catalytic combustor uses a flameless catalytic combustion module, followed by completion of combustion (at lower temperatures) downstream of the catalyst.

Post-combustion NO_x Control Technologies. Three post-combustion controls are available for combustion turbines: (1) SCR, (2) SCONOx™ (that is, EMx), and (3) selective non-catalytic reduction (SNCR). Both SCR and EMx control technologies use a catalyst bed to control the NO_x emissions and, combined with DLN or water injection, are capable of achieving NO_x emissions levels of 2.0 ppmvd for combined-cycle gas turbines and 2.5 ppmvd for simple-cycle combustion turbines. EMx uses a hydrogen regeneration gas to convert the NO_x to elemental N_2 and water. SNCR also uses ammonia to control NO_x emissions but without a catalyst.

Selective Catalytic Reduction. SCR is a post-combustion control technology designed to control NO_x emissions from gas turbines. The SCR system is placed inside the exhaust ductwork and consists of a catalyst bed with an ammonia injection grid located upstream of the catalyst. The ammonia reacts with the NO_x and O_2 in the presence of a catalyst to form N_2 and water. The catalyst consists of a support system with a catalyst coating typically of titanium dioxide, vanadium pentoxide, or zeolite. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream; this is referred to as "ammonia slip."

EMx System. The EMx system uses a single catalyst to remove NO_x emissions in the turbine exhaust gas by oxidizing NO to NO_2 and then absorbing NO_2 onto the catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx catalyst is from 300 to 700 degrees Fahrenheit (°F). EMx does not use ammonia, so there are no ammonia emissions from this catalyst system (CARB, 2004).

When all of the potassium carbonate absorber coating has been converted to N_2 compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N_2. Carbon dioxide (CO_2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst (CARB, 2004).

Selective Non-catalytic Reduction. SNCR involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600 to 2,100 °F[2]. This technology is not available for combustion turbines because gas turbine exhaust temperatures are below the minimum temperature required of 1,600°F.

2.2.1.2 Eliminate Technically Infeasible Options – Step 2

Pre-combustion NO_x Control Technologies

Water or Steam Injection. The use of water or steam injection is considered a feasible technology for reducing NO_x emissions to 25 ppmvd when firing natural gas under most ambient conditions. Combined with SCR, water or steam injection can achieve the proposed NO_x emission levels but at a slightly lower thermal efficiency as compared to DLN combustors.

DLN Combustors. The use of DLN combustors is a feasible technology for reducing NO_x emissions from the HBEP. DLN combustors are capable of achieving 9 to 25 ppmvd NO_x emissions over a relatively large operating range (70 to 100 percent load), and when combined with SCR can achieve the proposed NO_x emission levels.

The XONON™ technology has been demonstrated successfully in a 1.5-MW simple-cycle pilot facility, and it is commercially available for turbines rated up to 10 MW, but catalytic combustors such as XONON™ have not been demonstrated on an industrial E Class gas turbine. Therefore, the technology is not considered feasible for the proposed HBEP.

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[2] http://www.icac.com/i4a/pages/index.cfm?pageid=3399

Post-combustion NO_x Control Technologies

Selective Catalytic Reduction. The use of SCR, with an ammonia slip of less than 5 part(s) per million (ppm), is considered a feasible technology for reducing NO_x emissions to the proposed levels.

EMx System. In the Palmdale Hybrid Power Project PSD permit, EPA noted that it appears EMx has only been demonstrated to achieve 2.5 ppm NO_x (EPA, 2011a). In addition, the BAAQMD concluded in a recent permitting case that "it is clear that EMx is not as developed as SCR at this time and cannot achieve the same level of emissions performance that SCR is capable of" (BAAQMD, 2011). Therefore, EMx technology is not considered feasible for achieving the proposed levels.

Selective Non-catalytic Reduction. SNCR requires a temperature window that is higher than the exhaust temperatures from natural-gas-fired combustion turbine installations. Therefore, SNCR is not considered technically feasible for the proposed HBEP.

2.2.1.3 Combustion Turbine NO_x Control Technology Ranking – Step 3

Based on the preceding discussion, the use of water injection, DLN combustors, and SCR are the effective and technically feasible NO_x control technologies available for the HBEP. DLN combustors were selected because these allow for lower NO_x emission rates (9 ppmvd) from the combustion turbine over either water or steam (wet) injection (25 ppmvd). Furthermore, DLN combustors result in a very slight improvement in thermal efficiency over the wet injection NO_x control alternative and reduce the HBEP's water consumption. When used in combination with SCR, these technologies will control NO_x emissions to the proposed levels.

Applicable BACT clearinghouse determinations and the BAAQMD, CARB, SCAQMD, and SJVAPCD BACT determinations were reviewed to identify which NO_x emission rates have been achieved in practice for other natural-gas-fired combustion turbine projects. The results of this review for combined-cycle combustion turbines are presented in Table 2-2A and simple-cycle combustion turbines in Table 2-2B.

TABLE 2-2A
Summary of NO_x Emission Limits for Combined-cycle Combustion Turbines
Technology Ranking for Turbines

Facility	Facility ID Number	NO_x Emission Limit at 15 percent O_2
CPV St. Charles	MD-0040	2.0 ppm (3-hour)
Bosque County Power Plant	TX-0540	2.0 ppm (24-hour)
Lake Side Power Plant	UT-0067	2.0 ppm (3-hour)
Empire Power Plant	NY-0100	2.0 ppm (3-hour) without duct burners
Tracy Substation Expansion Project	NV-0035	2.0 ppm (3-hour)
Langley Gulch Power Plant	ID-0018	2.0 ppm (3-hour)
Palomar Escondido – SDG&E	2001-AFC-24	2.0 ppm (1-hour); 2.0 ppm (3-hour) with duct burners or transient hour of +25 MW
Warren County Facility	VA-0308	2.0 ppm with or without duct burners
Ivanpah Energy Center, L.P.	NV-0038	2.0 ppm (1-hour) without duct burners; 13.96 lb/hr with duct burners
Gila Bend Power Generating Station	AZ-0038	2.0 ppm (1-hour)
Duke Energy Arlington Valley	AZ-0043	2.0 ppm (1-hour)
Colusa II Generation Station	2006-AFC-9	2.0 ppm (1-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	2.0 ppm (1-hour)
Russell City Energy Center	2001-AFC-7	2.0 ppm (1-hour)
CPV Warren	VA-0291	2.0 ppm (1-hour)
IDC Bellingham	CA-1050	2.0 ppm/1.5 ppm (1-hour)

TABLE 2-2A
Summary of NO_x Emission Limits for Combined-cycle Combustion Turbines
Technology Ranking for Turbines

Facility	Facility ID Number	NO_x Emission Limit at 15 percent O_2
Oakley Generating Station	2009-AFC-4	2.0 ppm (1-hour)
GWF Tracy Combined-cycle Project	2008-AFC-7	2.0 ppm (1-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm (1-hour)
Magnolia Power Project	CA-1097	2.0 ppm (3-hour)
Otay Mesa Energy Center, LLC	CA-1177	2.0 ppm (1-hour)
FPL Turkey Point Power Plant	FL-0263	2.0 ppm (24-hour)
FPL West County Energy Center	FL-0286	2.0 ppm (24-hour)
Linden Generating Station – PSEG Fossil, LLC	NJ-0058	2.0 ppm
Caithnes Bellport Energy Center	NY-0095	2.0 ppm
Athens Generating Plant	NY-0098	2.0 ppm (3-hour)
El Segundo Repower Project	115663	2.0 ppm (1-hour)
LADWP Scattergood	800075	2.0 ppm (1-hour)
Wanapa Energy Center	OR-0041	2.0 ppm (3-hour)
King Power Station	TX-0590	2.0 ppm (1-hour)
Warren County Power Plant – Dominion	VA-0315	2.0 ppm (1-hour)
Western Midway Sunset Power Project	99-AFC-09	2.0 ppm (1-hour)
Sacramento Municipal Utility District	CA-0997	2.0 ppm

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.0 ppm NO_x identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the California Energy Commission (EPA, 2015 and CEC, 2015)

Combined-cycle Review

The review of these recent determinations, presented in Table 2-2A, shows that one facility, IDC Bellingham Project, has been issued a lower NO_x emission limit than the proposed BACT emission limit for the HBEP of 2.0 ppm NO_x. The IDC Bellingham Project was never built; therefore, that emission limit was never achieved in practice. As a result, the proposed emission rate of 2.0 ppm (1-hour) for the HBEP is the lowest NO_x emission rate achieved in practice for similar sources and, therefore, is proposed as the BACT NO_x emission limit.

Simple-cycle Review

Table 2-2B presents the recent BACT determinations for simple-cycle projects and shows that the proposed BACT emission limit for the HBEP of 2.5 ppm NO_x is consistent with recent BACT determinations for simple-cycle turbines.

Auxiliary Boiler

The HBEP auxiliary boiler proposes to use low-NO_x burners and SCR to control NO_x emissions to 5 ppm. A review of EPA's RACT/BACT/LAER Clearinghouse does not produce any projects with NO_x determinations as low as proposed for the HBEP's auxiliary boiler (the lowest determination being 7 ppm for the Stockton Cogen project – RBLC – CA-1206). A review of the SCAQMD's recent permitting actions for the El Segundo Power Redevelopment Project (ID 115663) shows that the proposed HBEP auxiliary boiler's NOx emission rate of 5 ppmvd is consistent with the SCAQMD's recent auxiliary boiler BACT determination (July 2015) for the El Segundo project's auxiliary boiler.

TABLE 2-2B
Summary of NO_x Emission Limits for Simple-cycle Combustion Turbines
Technology Ranking for Turbines

Facility	Facility ID Number	NO_x Emission Limit at 15 percent O_2
Lambie Energy Center	CA-1098	2.5 ppm (3-hour)
El Cajon Energy, LLC	CA-1174	2.5 ppm (1-hour)
Escondido Energy Center	CA-1175	2.5 ppm (1-hour)
Orange Grover Project	CA-1176	2.5 ppm (1-hour)
Rincon Power Plant	GA-0098	2.5 ppm
Bayonne Energy Center	NJ-0075	2.5 ppm
Kearny Generating Station – PSEG Fossil, LLC	NJ-0076	2.5 ppm (3-hour)
Howard Down Station	NJ-0077	2.5 ppm (3-hour)
Jasper County Generating Facility – SCE&G	SC-0064	2.5 ppm
Tenaska Bear Garden Station	VA-0250	2.5 ppm (3-hour)
Carlsbad Energy Center	07-AFC-06C	2.5 ppm (1-hour)
Pio Pico Energy Center	11-AFC-1C	2.5 ppm (1-hour)
Canyon Power Plant	07-AFC-9C	2.5 ppm (1-hour)
LADWP Scattergood Generating Station	800075	2.5 ppm (1-hour)
LADWP Haynes Generating Station	800074	2.5 ppm (1-hour)
El Segundo Power Redevelopment Project	115663	2.5 ppm (1-hour)

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.5 ppm NO_x identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the California Energy Commission (EPA, 2015 and CEC, 2015)

2.2.1.4 Evaluate Most-effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, the proposed NO_x emission rates (combined-cycle of 2.0 ppm, simple-cycle of 2.5 ppm, and the auxiliary boiler at 5 ppm) are the lowest NO_x emission rates achieved in practice at similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.1.5 NO_x BACT Selection – Step 5

The proposed BACT for NO_x emissions from the HBEP is the use of DLN combustors with SCR to control NO_x emissions from the CTGs and flue gas recirculation and SCR to control NO_x emissions from the auxiliary boiler.

2.2.2 CO

CO is discharged into the atmosphere when some of the fuel remains unburned or is only partially burned (incomplete combustion) during the combustion process. CO emissions are also affected by the gas turbine operating load conditions. CO emissions can be higher for gas turbines operating at low loads than for similar gas turbines operating at higher loads (EPA, 2006).

2.2.2.1 Identification of Combustion Turbine CO Emissions Control Technologies – Step 1

Effective combustor design and post-combustion control using an oxidation catalyst are two technologies (discussed below) for controlling CO emissions from a combustion turbine. As noted in the NO_x BACT analysis, the EMx and XONON technologies were determined to not be feasible for the HBEP.

Best Combustion Control. CO is formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of CO is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures (in excess of 1,800 °F) with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of CO but increase the formation of NO_x. The application of water injection or staged combustion (DLN combustors) tends to lower combustion temperatures (in order to reduce NO_x formation), potentially increasing CO formation. However, using good combustor design and following best operating practices will minimize the formation of CO while reducing the combustion temperature and NO_x emissions.

Oxidation Catalyst. An oxidation catalyst is typically a precious metal catalyst bed located in the HRSG. The catalyst enhances oxidation of CO to CO_2, without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

2.2.2.2 Eliminate Technically Infeasible Options – Step 2

Using good combustor design, following best operating practices, and using an oxidation catalyst are technically feasible options for controlling CO emissions from the proposed HBEP.

2.2.2.3 Combustion Turbine CO Control Technology Ranking – Step 3

Based on the preceding discussion, using best combustor control and an oxidation catalyst are technically feasible combustion turbine control technologies available to control CO emissions. Accordingly, AES proposes to control CO emissions using both methods to meet the proposed levels.

Applicable BACT clearinghouse determinations and the SCAQMD, EPA, BAAQMD, CARB, and SJVAPCD BACT determinations were reviewed to determine whether CO emission rates less than the proposed HBEP levels have been achieved in practice for other natural-gas-fired combustion turbine projects. The results of this review for combined-cycle combustion turbines are presented in Table 2-3A and simple-cycle combustion turbines in Table 2-3B. As these tables demonstrate, most projects have CO emission rates that are the same as or higher than the CO emission rate proposed for the HBEP.

TABLE 2-3A
Summary of CO Emission Limits for Combined-cycle Combustion Turbines
Emission Control Ranking for Turbines

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2
Lawrence Energy	OH-0248	2.0 ppm without duct burners
Berrien Energy, LLC	MI-0366	2.0 ppm without duct burners (3-hour)
COB Energy Facility	OR-0039	2.0 ppm (4-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	2.0 ppm (3-hour)
Wallula Power Plant	WA-0291	2.0 ppm (3-hour)
Duke Energy Arlington Valley (AVEFII)	AZ-0043	2.0 ppm (3-hour)
Wanapa Energy Center	OR-0041	2.0 ppm (3-hour)
Vernon City Light and Power	CA-1096	2.0 ppm (3-hour)
Mariposa Energy Project	2009-AFC-3	2.0 ppm (3-hour)
Palmdale Hybrid Power Plant Project	08-AFC-9	2.0 ppm without duct burners (1-hour)

TABLE 2-3A
Summary of CO Emission Limits for Combined-cycle Combustion Turbines
Emission Control Ranking for Turbines

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2
Wansley Combined-cycle Energy Facility	GA-0102	2.0 ppm with duct burners
McIntosh Combined-cycle Facility	GA-0105	2.0 ppm with duct burners
Sumas Energy 2 Generation Facility	WA-0315	2.0 ppm (1-hour)
Oakley Generating Station	2009-AFC-4	2.0 ppm (1-hour)
Goldendale Energy	WA-302	2.0 ppm (1-hour)
IDC Bellingham	CA-1050	2.0 ppm (1-hour)
Russell City Energy Center	2001-AFC-7	2.0 ppm with duct burners (1-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm with duct burners (1-hour)
Magnolia Power Project	CA-1097	2.0 ppm with duct burners (1-hour)
Kelson Ridge	MD-0033	2.0 ppm (3-hour)
Liberty Generating Station	NJ-0043	2.0 ppm
Linden Generating Station – PSEG Fossil, LLC	NJ-0058	2.0 ppm
Cogen Technologies Linden Venture, L.P.	NJ-0059	2.0 ppm
Caithnes Bellport Energy Center	NY-0095	2.0 ppm
LADWP Scattergood	800075	2.0 ppm (1-hour)
El Segundo Repower Project	115663	2.0 ppm (1-hour)
CPV Warren	VA-0291	1.3 ppm without duct burners; 1.2 ppm with duct burners
Warren County Power Station - Dominion	VA-0308	1.3 ppm without duct burners
Kleen Energy Systems	CT-0151	0.9 ppm (1-hour)

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.0 ppm CO identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the California Energy Commission (EPA, 2015 and CEC, 2015).

TABLE 2-3B
Summary of CO Emission Limits for Simple-cycle Combustion Turbines
Emission Control Ranking for Turbines

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2
Great River Energy – Elk River Station	MN-0075	4.0 ppm (4-hour)
Carlsbad Energy Center	07-AFC-06C	4.0 ppm (1-hour)
Pio Pico Energy Center	11-AFC-1C	4.0 ppm (1-hour)
Canyon Power Plant	07-AFC-9C	4.0 ppm (1-hour)
LADWP Scattergood Generating Station	800075	4.0 ppm (1-hour)
LADWP Haynes Generating Station	800074	4.0 ppm (1-hour)
El Segundo Power Redevelopment Project	115663	4.0 ppm (1-hour)

TABLE 2-3B
Summary of CO Emission Limits for Simple-cycle Combustion Turbines
Emission Control Ranking for Turbines

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 4.0 ppm CO identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the California Energy Commission (EPA, 2015 and CEC, 2015).

Combined-cycle Review

Three recent BACT determinations have lower CO emission rates than the HBEP combined-cycle units. These three projects are discussed below.

Competitive Power Ventures (CPV) Warren and Warren County Power Station. The CPV Warren and Warren County Power Station are the same project as Dominion Resources Service, Inc. purchased the CPV Warren Project. The final PSD permit includes CO emission limits of 1.5 ppm and 2.4 ppm, on a 1-hour averaging basis for operating conditions without and with duct burners, respectively. Based on publically available information, the Warren County Power Station became operational in December 2014. Therefore, this level of control has not been demonstrated in practice on a long-term basis.

Kleen Energy Systems. The Kleen Energy Systems facility conducted the initial source tests in June 2011. Based on a November 2011 letter from the Connecticut Department of Energy & Environmental Protection, the facility was able to successfully demonstrate compliance with the CO emission limits of 0.9 ppm (1-hour). However, the Kleen Energy Systems air permit exempts CO emissions during load rate changes (i.e., non-steady state operation) from the CO 1-hour averaging period, which has the effect of relaxing the standard if frequent load rate changes occurred over the course of the averaging period.[3]

Conclusion. With the exception of the Kleen Energy System facility, the proposed HBEP CO emission rate of 2.0 ppmvd (1-hour) is the lowest CO emission rate achieved in practice during all phases of operation excluding startup and shutdowns.

Simple-cycle Review

The recent simple-cycle BACT determinations are consistent with the proposed HBEP BACT level of 4.0 ppm.

Auxiliary Boiler

The HBEP auxiliary boiler proposes to use low-NO_x burners and good combustion design to control CO emissions to 50 ppm. A review of the SCAQMD's recent permitting actions for the El Segundo Power Redevelopment Project (Facility ID 115663) shows that the Amended HBEP auxiliary boiler's CO emission rate of 50 ppmvd is consistent with the SCAQMD's recent auxiliary boiler BACT determination (July 2015) for the El Segundo Power Redevelopment Project's auxiliary boiler.

2.2.2.4 Evaluate Most Effective Controls and Document Results – Step 4

The proposed CO emission rates for the HBEP are consistent with recent CO BACT determinations achieved or verified with long-term compliance records for other similar facilities. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.2.5 CO BACT Selection – Step 5

The BACT for CO emissions from the HBEP is good combustion design and the installation of an oxidation catalyst system.

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[3] This source shall not exceed the emission limits stated herein at any time as determined in accordance with the applicable averaging periods defined in Part III of this permit or as specified in an approved stack test protocol, **except during periods of start-up, shut-down, shifts between loads**, fuel switching, equipment cleaning, emergency, and/or malfunction.

2.2.3 VOC

The pollutants commonly classified as VOC are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned (incomplete combustion) during the combustion process

2.2.3.1 Identification of Combustion Turbine VOC Emissions Control Technologies – Step 1

Effective combustor design and post-combustion control using an oxidation catalyst are two technologies for controlling VOC emissions from a combustion turbine. The industrial combustion turbines proposed for the HBEP are able to achieve relatively low, uncontrolled VOC emissions of approximately 3 ppmvd because the combustors have a firing temperature of approximately 2,500 °F with an exhaust temperature of approximately 1,000 °F. A DLN-equipped combustion turbine that incorporates an oxidation catalyst system can achieve VOC emissions in the 2 ppmvd range. As noted in the NO_x BACT analysis, the EMx and XONON technologies were determined to not be feasible for the HBEP.

Best Combustion Control. As previously discussed, VOC is formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of VOC is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of VOC but increase the formation of NO_x. The application of water injection or staged combustion (DLN combustors) tends to lower combustion temperatures (to reduce NO_x formation), potentially increasing VOC formation. However, good combustor design and best operating practices will minimize the formation of VOC while reducing the combustion temperature and NO_x emissions.

Oxidation Catalyst. An oxidation catalyst is typically a precious metal catalyst bed located in the exhaust duct. The catalyst enhances oxidation of VOC to CO_2 without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

2.2.3.2 Eliminate Technically Infeasible Options – Step 2

Good combustor design and the use of an oxidation catalyst are both technically feasible options for controlling VOC emissions from the proposed HBEP.

2.2.3.3 Combustion Turbine VOC Control Technology Ranking – Step 3

Based on the preceding discussion, using good combustor control and an oxidation catalyst are technically feasible combustion turbine control technologies available to control VOC emissions. Accordingly, a VOC emission limit of 2.0 ppmvd (1-hour) for both the combined- and simple-cycle turbines is proposed.

Applicable BACT clearinghouse determinations and the SCAQMD, EPA, BAAQMD, CARB, and SJVAPCD BACT determinations were reviewed to determine whether VOC emission rates less than the proposed HBEP levels have been achieved in practice for other natural-gas-fired combustion turbine projects. The results of this review for combined-cycle combustion turbines are presented in Table 2-4A and simple-cycle combustion turbines in Table 2-4B.

Combined-cycle Review

Based on a review of Table 2-4A, a number of recent combined-cycle projects have been permitted and are operational with VOC limits lower than the HBEP's proposed 2.0 ppm limit. All of these projects employ the use of good combustion control and the use of an oxidation catalyst to control VOC emissions, identical to the HBEP. Given the HBEP's use of the same control technologies, it is reasonable to assume the HBEP will emit VOC at comparable emission rates as these projects. However, a review of the air permits for some of these facilities shows that compliance with these lower emissions are determined using test methods other than the SCAQMD's Reference Method 25.3. As such, the proposed combined-cycle level of 2.0 ppm is proposed as BACT. Furthermore, the SCAQMD's recent (July 2015) VOC BACT determination for the El Segundo Repower Project's GE Frame 7FA.05 combined-cycle units was 2 ppm, consistent with the proposed HBEP VOC emission limits.

TABLE 2-4A

Summary of VOC Emission Limits for Combined-cycle Combustion Turbines

Emission Control Ranking for Turbines

Facility	Facility ID Number	VOC Emission Limit at 15 percent O_2
Florida Power and Light Martin Plant	FL-0244	1.3 ppm without duct burners
Duke Energy Arlington Valley (AVEFII)	AZ-0043	1 ppm without duct burners (3-hour)
Fairbault Energy Park	MN-0071	1.5 ppm without duct burners
VA Power – Possum Point	VA-0255	1.2 ppm without duct burners
Los Esteros Critical Energy Facility – Phase 2c	2003-AFC-2	2.0 ppm with duct burners (3-hour)
GWF Tracy Combined-cycle Project	2008-AFC-7	1.5 ppm without duct burners (3-hour); 2.0 ppm with duct burners (3-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	1.4 ppm without duct burners; 2.0 ppm with duct burners (3-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm without duct burners (1-hour); 2.0 ppm with duct burners (1-hour)
Palmdale Hybrid Power Plant Project	SE 09-01	1.4 without duct burners (1-hour); 2.0 ppm with duct burners (1-hour)
Victorville Hybrid Gas-Solar	2007-AFC-1	1.4 ppm without duct burners; 2.0 ppm with duct burners
Colusa II Generation Station	2006-AFC-9	1.38 ppm without duct burners; 2.0 ppm with duct burners
FPL Turkey Point Power Plant	FL-0263	1.6 ppm without duct burners; 1.9 with duct burners
West Deptford Energy	NJ-0074	1.9 ppm (1-hour)
Plant McDonough Combined-cycle	GA-0127	1.0 ppm (1-hour) without; 1.8 ppm with duct burners (3-hour)
King Power Station	TX-0590	1.8 ppm (3-hour)
CPV Cunningham Creek	VA-0261	1.8 ppm
FPL West County Energy Center Unit 3	FL-0303	1.2 ppm with duct burners; 1.5 with duct burners
FPL West County Energy Center	FL-0286	1.5 ppm
Gila Bend Power Generating Station	AZ-0038	1.4 ppm with duct burners
Western Midway Sunset Powre Project	99-AFC-09	1.4 ppm (3-hour)
Genova Arkansas I, LLC	AR-0070	1.4 ppm
CPV Atlantic Power Generating Facility	FL-0219	1.4 ppm
El Paso Broward Energy Center	FL-0225	1.4 ppm
El Paso Manatee Energy Center	FL-0226	1.4 ppm
El Paso Belle Glade Energy Center	FL-0227	1.4 ppm
Ninemile Point Electric Generating Plant	LA-0254	1.4 ppm (1-hour)
Mountainview Power	CA-0949	1.4 ppm
Sacramento Municipal Utility District	CA-0997	1.4 ppm
FPL Manatee Plant – Unit 3	FL-0245	1.3 ppm
Teco Bayside Power Station	FL-0246	1.3 ppm
Cogen Technologies Linden Venture, L.P.	NJ-0059	1.2 ppm
Conectiv Bethlehem, Inc.	PA-0189	1.2 ppm

TABLE 2-4A
Summary of VOC Emission Limits for Combined-cycle Combustion Turbines
Emission Control Ranking for Turbines

Facility	Facility ID Number	VOC Emission Limit at 15 percent O_2
Liberty Generating Station	NJ-0043	1.0 ppm (no duct burners)
Empire Power Plant	NY-0100	1.0 ppm (no duct burners)
Fairbault Energy Park	MN-0053	1.0 ppm (3-hour) (no duct burners)
Oakley Generating Station	2009-AFC-4	1.0 ppm (1-hour) (no duct burners)
Sutter – Calpine	1997-AFC-02	1.0 ppm with duct burners (calendar day average)
Russell City Energy Center	2001-AFC-7	1.0 ppm with duct burners (1-hour)
LADWP Scattergood Generating Station	800075	2.0 ppm (1-hour)
El Segundo Repower Project	115663	2.0 ppm (1-hour)
CPV Warren	VA-0291	0.7 without duct burners; 1.6 with duct burners; (3-hour)
Warren County Facility	VA-0308	0.7 without duct burners; 1.0 with duct burners
Chouteau Power Plant	OK-0129	0.3 ppm (3-hour) with duct burners

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.0 ppm VOC identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the CEC (EPA, 2012 and CEC, 2012).

Simple-cycle Review

Based on a review of Table 2-4b, a number of recent simple-cycle projects have been permitted and are operational with VOC limits lower than the HBEP's proposed 2.0 ppm limit. All of these projects employ the use of good combustion control and the use of an oxidation catalyst to control VOC emissions, identical to the HBEP. Given the same level of control, it's reasonable to assume the HBEP will emit VOC at comparable emission rates as these projects. However, a review of the air permits for some of these facilities shows that compliance with these lower emissions are determined using test methods other than the SCAQMD's Reference Method 25.3. As such, the proposed simple-cycle level of 2.0 ppm is proposed as BACT. Furthermore, the SCAQMD's recent (July 2015) VOC BACT determination for the El Segundo Repower Project's GE LMS100 simple-cycle units was 2 ppm, consistent with the proposed HBEP VOC emission limits.

TABLE 2-4B
Summary of VOC Emission Limits for Simple-cycle Combustion Turbines
Emission Control Ranking for Turbines

Facility	Facility ID Number	VOC Emission Limit at 15 percent O_2
Indigo Energy Facility	CA-0951	2.0 ppm
LA Dept. of Water & Power	CA-0952	2.0 ppm
Alliance Colton – Century	CA-0953	2.0 ppm
El Colton, LLC	CA-1095	2.0 ppm (3-hour)
LADWP Haynes Generating Station	800074	2.0 ppm (1-hour)
LADWP Scattergood Generating Station	800075	2.0 ppm (1-hour)
El Segundo Repower Project	115663	2.0 ppm (1-hour)
Escondido Energy Center, LLC	CA-1175	2.0 ppm (1-hour)

TABLE 2-4B
Summary of VOC Emission Limits for Simple-cycle Combustion Turbines
Emission Control Ranking for Turbines

Facility	Facility ID Number	VOC Emission Limit at 15 percent O_2
Orange Grover Project	CA-1176	2.0 ppm (1-hour)
Rincon Power Plant	GA-0098	2.0 ppm
Renaissance Power, LLC	MI-0267	2.0 ppm
El Paso Belle Glade Energy Center	FL-0227	1.4 ppm
Deerfield Beach Energy Center	FL-0228	1.4 ppm
Pompano Beach Energy Center	FL-0229	1.4 ppm
FPL Manatee Plant – Unit 3	FL-0245	1.3 ppm
Progress Bartow Power Plant	FL-0285	1.2 ppm

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.0 ppm VOC identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the CEC (EPA, 2012 and CEC, 2012).

Auxiliary Boiler

The HBEP auxiliary boiler proposes to use low-NO_x burners, clean burning natural gas, and good combustion design to control VOC emissions. A review of the SCAQMD's recent permitting actions for the El Segundo Power Redevelopment Project (Facility ID 115663) shows that the Amended HBEP auxiliary boiler's emission controls are consistent with the SCAQMD's recent BACT determination (July 2015) for the El Segundo Power Redevelopment Project's auxiliary boiler.

2.2.3.4 Evaluate Most Effective Controls and Document Results – Step 4

The proposed combined and simple-cycle VOC emission rate of 2.0 ppmvd (1-hour) is not the lowest VOC emission rate shown, but is consistent with most BACT determinations and recent BACT determinations issued by the SCAQMD.

2.2.3.5 VOC BACT Selection – Step 5

The BACT for VOC emissions from the HBEP is good combustion design and the installation of an oxidation catalyst system to control VOC emissions from the combustion turbines to 2.0 ppmvd (1-hour).

2.2.4 PM_{10} and $PM_{2.5}$

PM from natural gas combustion has been estimated to be less than 1 micron in equivalent aerodynamic diameter, has filterable and condensable fractions, and is usually hydrocarbons of larger molecular weight that are not fully combusted (EPA, 2006). Because the PM is less than 2.5 microns in diameter, the BACT control technology discussion assumes the control technologies for PM_{10} and $PM_{2.5}$ are the same.

2.2.4.1 Identification of Combustion Turbine PM_{10} and $PM_{2.5}$ Emissions Control Technologies – Step 1

Pre-combustion Particulate Control Technologies. The major sources of PM_{10} and $PM_{2.5}$ emissions from a natural-gas-fired gas turbine equipped with SCR for post-combustion control of NO_x are: (1) the conversion of fuel sulfur to sulfates and ammonium sulfates; (2) unburned hydrocarbons that can lead to the formation of PM in the exhaust stack; and (3) PM in the ambient air entering the gas turbine through the inlet air filtration system, and the aqueous ammonia dilution air. Therefore, the use of clean-burning, low-sulfur fuels such as natural gas will result in minimal formation of PM_{10} and $PM_{2.5}$ during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can lead to formation of PM at the stack. In addition to good combustion, use of high-efficiency filtration on the inlet air and SCR dilution air system will minimize the entrainment of PM into the exhaust stream.

Post-combustion Particulate Control Technologies. Two post-combustion control technologies designed to reduce PM emissions from industrial sources are electrostatic precipitators and baghouses. However, neither of these control technologies is appropriate for use on natural-gas-fired turbines because of the very low levels and small aerodynamic diameter of PM from natural gas combustion.

2.2.4.2 Eliminate Technically Infeasible Options – Step 2

Electrostatic precipitators and baghouses are typically used on solid/liquid-fuel fired or other types of sources with high PM emission concentrations, and are not used in natural-gas-fired applications, which have inherently low PM emission concentrations. Therefore, electrostatic precipitators and baghouses are not considered technically feasible control technologies. However, best combustion practices, clean-burning fuels, and inlet air filtration are considered technically feasible for control of PM_{10} and $PM_{2.5}$ emissions from the HBEP.

2.2.4.3 Combustion Turbine PM_{10} and $PM_{2.5}$ Control Technology Ranking – Step 3

The use of best combustion practices, clean-burning fuels, and inlet air filtration are the technically feasible natural-gas-fired turbine control technologies proposed by AES to control PM_{10} and $PM_{2.5}$ emissions to 8.5 lb/hr for the combined-cycle turbines and 6.24 lb/hr for the simple-cycle turbines. Furthermore, because no add-on control devices are technically feasible to control PM emissions from natural-gas-fired turbines, there would be little an applicant could do beyond using best combustion practices and using clean-burning fuels to control particulate emissions.

2.2.4.4 Evaluate Most Effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, using proposed good combustion practice and pipeline-quality natural gas to control $PM_{10}/PM_{2.5}$ emissions to 8.5 lb/hr for the combined-cycle turbines, 6.24 lb/hr for the simple-cycle turbines, and auxiliary boiler are consistent with BACT at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.4.5 PM_{10} and $PM_{2.5}$ BACT Selection – Step 5

The BACT for $PM_{10}/PM_{2.5}$ emissions from the HBEP is using good combustion practices and pipeline-quality natural gas to control $PM_{10}/PM_{2.5}$ emissions.

2.2.5 SO_2

Emissions of SO_2 are entirely a function of the sulfur content in the fuel rather than any combustion variables. During the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2.

2.2.5.1 Identification of Combustion Turbine SO_2 Emissions Control Technologies – Step 1

Two primary mechanisms are used to reduce SO_2 emissions from combustion sources: (1) reduce the amount of sulfur in the fuel, and (2) remove the sulfur from the combustion exhaust gases.

Limiting the amount of sulfur in the fuel is a common practice for natural-gas-fired turbines. For instance, natural-gas-fired turbines in California are typically required to combust only California Public Utilities Commission (CPUC) pipeline-quality natural gas with a sulfur content of less than 1 grain of sulfur per 100 standard cubic feet (scf). The HBEP would be supplied with natural gas from the Southern California Gas (SoCalGas) pipeline, which is limited by tariff Rule 30 to a maximum total fuel sulfur content of less than 0.75 grain of sulfur per 100 scf. Therefore, the use of pipeline-quality natural gas with low sulfur content is a BACT control technique for SO_2.

There are two principal types of post-combustion control technologies for SO_2—wet scrubbing and dry scrubbing. Wet scrubbers use an alkaline solution to remove the SO_2 from the exhaust gases. Dry scrubbers use an SO_2 sorbent injected as powder or slurry to remove the SO_2 from the exhaust stream. However, the SO_2 concentrations in the natural gas exhaust gases are too low for the scrubbing technologies to work effectively or to be technically feasible.

2.2.5.2 Eliminate Technically Infeasible Options – Step 2

Use of pipeline-quality natural gas with very low sulfur content is technically feasible for the HBEP. However, because sulfur emissions from natural-gas-fired turbines are extremely low when using pipeline-quality natural gas, the two post-combustion SO_2 controls for natural-gas fired turbines (wet and dry scrubbers) are not technically feasible.

2.2.5.3 Combustion Turbine SO_2 Control Technology Ranking – Step 3

Use of pipeline-quality natural gas with very low sulfur content is the only technically feasible SO_2 control technology for natural-gas-fired turbines, and it is the most effective SO_2 control technology used by all other natural-gas-fired turbines in California. Therefore, using pipeline-quality natural gas with a regulatory limit of 0.75 grain of sulfur per 100 scf of natural gas for the HBEP is BACT for SO_2.

2.2.5.4 Evaluate Most Effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, the use of pipeline-quality natural gas with a maximum of 0.75 grain of sulfur per 100 scf of natural gas as a BACT control technique for SO_2 will achieve the lowest SO_2 emission rates achieved in practice at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.5.5 SO_2 BACT Selection – Step 5

The BACT for SO_2 from the HBEP is use of pipeline-quality natural gas with a sulfur content of less than 0.75 grain of sulfur per 100 scf of natural gas.

2.2.6 BACT for Startups and Shutdowns

Startup and shutdown events are a normal part of the power plant operation, but they involve NO_x, CO, and VOC emissions rates that are highly variable and greater than emissions during steady-state operation[4]. This is because emission control systems are not fully functional during these events. In the case of the DLN combustors, the turbines must achieve a minimum operating rate before these systems are functional. Likewise, the SCR and oxidation catalyst systems must be heated to a specific minimum temperature before the catalyst systems become effective. Furthermore, startup and shutdown emissions are dependent on a number of project specific factors; therefore, permitted startup and shutdown emission limits are highly variable. For these reasons, BACT for startup and shutdown will consider only the duration of these events.

2.2.6.1 Control Devices and Techniques to Limit Startup and Shutdown Emissions

The available approach to reducing startup and shutdown emissions from combustion turbines is to use best work practices. By following the plant equipment manufacturers' recommendations, power plant operators can limit the duration of each startup and shutdown event to the minimum duration achievable. Plant operators also use their own operational experience with their particular turbines and ancillary equipment to optimize startup and shutdown emissions. The proposed numerical emission limits for the startups and shutdowns are outlined below.

2.2.6.2 Determination of BACT Emissions Limit for Startups and Shutdowns

Startups. The combustion turbine vendor (GE) has determined a turbine startup period of 15 to 20 minutes (hot/warm and cold starts) from first fire to full load operation for the combined-cycle turbines and 10 minutes from first fire to full load operation for the simple-cycle turbines. This startup period does not include the warm-up time required by the SCR and oxidation catalyst systems, which, for the combined-cycle turbines, is affected by the length of time the system has been inactive, as the length of time is related to the temperature and pressure of the steam cycle. For the combined-cycle turbines, two startup cases (hot/warm and cold) were provided based on engineering estimates to reflect the different length of time between combustion turbine activity. Table 2-5 presents the proposed startup emissions and durations proposed as BACT.

[4] Because $PM_{10/2.5}$ and SO_2 emissions are dependent on the amount of fuel combusted, $PM_{10/2.5}$ and SO_2 emissions during startup and shutdown would be less than full load operations since less fuel is consumed as compared to full load operations.

TABLE 2-5
Facility Startup Emission Rates Per Turbine

Startup	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Duration (minutes/event)
Combined-cycle Turbines							
Cold	61	325	36	61	325	36	60
Hot/Warm	17	137	25	25.2	142	25.8	30
Simple-cycle Turbines							
Start	16.6	15.4	2.8	20.7	19.4	4.0	30

lb/event = pound(s) per event

lb/hr = pound(s) per hour

Shutdowns. The turbine vendor also supplied the emission estimates for a typical shutdown event occurring over 30 minutes for the combined-cycle turbines and 13 minutes for the simple-cycle turbines. The shutdown process begins with the combustion turbine reducing load until the DLN system is no longer functional but the SCR and oxidation remain functional. Table 2-6 presents the shutdown emissions and duration proposed as BACT.

TABLE 2-6
Facility Shutdown Emission Rates Per Turbine

	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Duration (minutes/event)
Combined-cycle Shutdown	10	133	32	18.2	138	32.8	30
Simple-cycle Shutdown	3.1	28.1	3.1	9.6	34.4	4.9	13

2.2.6.3 Summary of the Proposed BACT for Startups and Shutdowns

AES proposes to limit individual startup and shutdown durations and emissions to an enforceable BACT permit limit, as shown in Tables 2-5 and 2-6.

SECTION 3
GHG BACT

3.1 Introduction

This BACT evaluation was prepared to address GHG emissions from the HBEP, and the evaluation follows EPA regulations and guidance for BACT analyses as well as EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (EPA, 2011b). GHG pollutants are emitted during the combustion process when fossil fuels are burned. One of the possible ways to reduce GHG emissions from fossil fuel combustion is to use inherently lower GHG-emitting fuels and to minimize the use of fuel, which in this case is achieved by using thermally efficient CTGs, well-designed HRSGs, and STGs to generate additional power from the heat of the CTG exhaust. In the HBEP process, the fossil fuel burned will be pipeline-quality natural gas, which is the lowest GHG-emitting fossil fuel available. The HBEP gas turbines selected to meet the Amended Project's objectives have a high operating turndown rate while maintaining a high thermal efficiency.

3.1.1 Regulatory Overview

Based on a series of actions, including the 2007 Supreme Court decision, the 2009 EPA Endangerment Finding and Cause and Contribute Finding, and the 2010 Light-Duty Vehicle Rule, GHGs became subject to permitting under the CAA. In May 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule), in which EPA defined six GHG pollutants (collectively combined and measured as carbon dioxide equivalent [CO_2e]) as NSR-regulated pollutants and, therefore, subject to PSD permitting when new projects emitted those pollutants above certain threshold levels. Under the GHG Tailoring Rule, beginning July 1, 2011, new sources with a GHG PTE equal to or greater than 100,000 tpy of CO_2e would be considered a major source and would be required to undergo PSD permitting, including preparation of a BACT analysis for GHG emissions. Modifications to existing major sources (CO_2e PTE of 100,000 tpy or greater) that result in an increase of CO_2e greater than 75,000 tpy would be similarly required to obtain a PSD permit, which includes a GHG BACT analysis. However, in July 2014, the U.S. Supreme Court ruled that EPA could not regulate GHG emissions alone. As a result, new sources with a GHG PTE equal to or greater than 100,000 tpy of CO_2e are no longer required to obtain a PSD permit specifically for GHG emissions. Rather, a BACT analysis to evaluate GHG emissions control would only be required if the new source would require a PSD permit as a result of criteria pollutant PTE. The Amended Project results in emission increases above the new source PSD thresholds for at least one criteria pollutant. Therefore, the Amended Project is subject to the GHG Tailoring Rule, and is required to conduct a GHG BACT analysis.

3.1.2 BACT Evaluation Overview

BACT requirements are intended to ensure that a proposed project will incorporate control systems that reflect the latest control technologies that have been demonstrated in practice for the type of facility under review. BACT is defined under the CAA (42 U.S.C. Section 7479[3]) as follows:

> *The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. BACT is defined as the emission control means an emission limitation (including opacity limits) based on the maximum degree of reduction which is achievable for each pollutant, taking into account energy, environmental, and economic impacts, and other costs. ….*

EPA guidance specifies that a BACT analysis should be performed using a top-down approach in which all applicable control technologies are evaluated based on their effectiveness and are then ranked by decreasing level of control. If the most-effective control technology is not being selected for the project, the control technologies on the list are evaluated as to whether they are infeasible because of energy, environmental, and/or economic impacts. The most effective control technology in the ranked list that cannot be so eliminated is then defined as BACT for that pollutant and process. A further analysis must be conducted to establish the emission limit that is BACT, based on determining the lowest emission limit that is expected to be consistently achievable over the life of the plant, taking into account site-specific and project-specific requirements.

For a facility subject to the GHG Tailoring Rule, the six covered GHG pollutants are:

- CO_2
- Nitrous oxide (N_2O)
- Methane (CH_4)
- Hydrofluorocarbons (HFC)
- Perfluorocarbons (PFC)
- Sulfur hexafluoride (SF_6)

Although the top-down BACT analysis is applied to GHGs, there are "unique" issues in the analysis for GHGs that do not arise in BACT for criteria pollutants (EPA, 2011b). For example, EPA recognizes that the range of potentially available control options for BACT Step 1 is currently limited and emphasizes the importance of energy efficiency in BACT reviews. Specifically, EPA states that (EPA, 2011b):

> *The application of methods, systems, or techniques to increase energy efficiency is a key GHG-reducing opportunity that falls under the category of "lower-polluting processes/practices." Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews. In some cases, a more energy efficient process or project design maybe used effectively alone; whereas in other cases, an energy efficient measure may be used effectively in tandem with end-of-stack controls to achieve additional control of criteria pollutants.*

Based on this reasoning, EPA provides permitting authorities with the discretion to use energy-efficient measures as "the foundation for a BACT analysis for GHGs . . ." (EPA, 2011b).

3.2 GHG BACT Analysis

3.2.1 Assumptions

During the completion of the GHG BACT analysis, the following assumptions were made:

- The HBEP BACT analysis for criteria pollutants will result in the installation of an SCR system for NO_x emissions reduction for the turbines and auxiliary boiler and an oxidation catalyst for control of CO and VOCs for each turbine.

- During actual combustion turbine operation, the oxidation catalyst may result in minimal increases in CO_2 from the oxidation of any CO and CH_4 in the flue gas. However, the EPA Final Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule) (40 CFR 98) factors for estimating CO_2e emissions from natural gas combustion assume complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the Mandatory Reporting Rule factors and included in the CO_2e totals.

- Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be very small or negligible. From the HBEP GHG emissions inventory, the estimated N_2O emissions only total 87.4 metric tons per year. Therefore, even if there were an order-of-magnitude increase in N_2O as a result of the SCR, the impact to CO_2e emissions would be insignificant as compared to total estimated HBEP CO_2e emissions.

Use of the SCR and oxidation catalyst slightly decreases the Amended Project's thermal efficiency due to backpressure on the turbines (these impacts are already included in the emission inventory) and, as noted above, may create a marginal but unquantifiable increase to N_2O emissions. Although elimination of the NO_x and CO/VOC controls could conceivably be considered as an option within the GHG BACT, the environmental benefits of the NO_x, CO, and VOC controls are assumed to outweigh the marginal increase to GHG emissions. Therefore, even if carried forward through the GHG BACT analysis, they would be eliminated in Step 4 because of other environmental impacts. Therefore, omission of these controls within the BACT analysis was not considered.

3.2.2 BACT Determination

The top-down GHG BACT determination for the combustion turbines and auxiliary boiler is presented below. This BACT analysis is based on one combined-cycle power block consisting of two combustion turbines with unfired HRSGs, a steam turbine, and an auxiliary boiler, and one simple-cycle power block consisting of two simple-cycle combustion turbines.

The primary GHG of concern for the HBEP is CO_2. This analysis primarily presents the GHG BACT analysis for CO_2 emissions because CH_4 and N_2O emissions are insignificant, at less than two percent of facility GHG CO_2e emissions. The HBEP will emit insignificant quantities of SF_6, HFC, or PFC pollutants, used in electrical switch gear and comfort cooling systems. Therefore, the primary sources of GHG emissions would be the natural-gas-fired combustion turbines and the natural-gas-fired auxiliary boiler.

This determination follows EPA's top-down analysis method, as specified in EPA's GHG Permitting Guidance (EPA, 2011b). The following top-down analysis steps are listed in EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate most effective controls and document results
- Step 5: Select BACT

Each of these steps, described in the following sections, was conducted for GHG emissions from the CTGs. The following top-down BACT analysis has been prepared in accordance with EPA's *New Source Review Workshop Manual* (EPA, 1990) and takes into account energy, environmental, economic, and other costs associated with each alternative technology.

The previous and current emission limits reported for combined-cycle and simple-cycle combustion turbines were based on a search of the various federal, state, and local BACT, RACT, and LAER databases. The search included the following databases:

- EPA BACT/LAER Clearinghouse (EPA, 2015)
  - Search included the CO_2 BACT/LAER determinations for combined-cycle and simple-cycle combustion turbines (greater than 25 MW) with permit dates for the years 2001 through 2015.
- BACT Analyses for Recently Permitted Combined-cycle and Simple-cycle CEC Projects (CEC, 2015)

3.2.2.1 Identification of Available GHG Emissions Control Technologies – Step 1

There are two basic alternatives for limiting GHG emissions from the HBEP equipment:

- Carbon capture and storage (CCS)
- Thermal efficiency

The proposed HBEP design and operation will consist of one combined-cycle power block, a simple-cycle power block, and an auxiliary boiler. The combined-cycle power block will consist of two natural-gas-fired GE Frame 7FA.05 CTGs with unfired HRSGs, one STG, and an auxiliary boiler to facilitate fast start capabilities. The simple-cycle power block will consist of two GE LMS-100PB CTGs. AES has determined that this configuration is the only alternative that meets all of the project objectives as further detailed in Section 1.2. Several of the primary objectives of the HBEP are to backstop variable renewable resources with a multiple stage generator project that incorporates fast start capability, a high degree of turndown, fast ramping capability, and a high thermal efficiency. Therefore, other potentially lower emitting renewable generation technologies were not evaluated in this BACT analysis because this would change the fundamental business purpose of the HBEP.

This is consistent with EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states:

> *EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant...", and "...the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility... (p. 26).*

The only identified GHG emission "control" options are post-combustion CCS and thermal efficiency of the proposed generation facility.

Carbon Capture and Storage. CCS technology is composed of three main components: (1) CO_2 capture and/or compression, (2) transport, and (3) storage.

CO_2 Capture and Compression. CCS systems involve use of adsorption or absorption processes to separate and capture CO_2 from the flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer, depleted coal seam, ocean storage site, or used in crude oil production for enhanced oil recovery.

The capture of CO_2 from gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure, CO_2 concentration, and contaminants in the gas or exhaust stream. Although CO_2 separation processes have been used for years in the oil and gas industries, the characteristics of the gas steams are markedly different than power plant exhaust. CO_2 separation from power plant exhaust has been demonstrated in large pilot-scale tests, but it has not been commercially implemented in full-scale power plant applications.

After separation, the CO_2 must be compressed to supercritical temperature and pressure for suitable pipeline transport and geologic storage properties. Although compressor systems for such applications are proven, commercially available technologies, specialized equipment is required, and operating energy requirements are very high.

CO_2 Transport. The supercritical CO_2 would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by ocean-going vessels.

Because of the extremely high pressures, as well as the unique thermodynamic and dense-phase fluid properties of supercritical CO_2, specialized designs are required for CO_2 pipelines. Control of potential propagation fractures and corrosion also require careful attention to contaminants such as oxygen, nitrogen, methane, water, and hydrogen sulfide.

While transport of CO_2 via pipeline is proven technology, doing so in urban areas will present additional concerns. Development of new rights-of-way in congested areas would require significant resources for planning and execution, and public concern about potential for leakage may present additional barriers.

CO_2 Storage. CO_2 storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage has not been demonstrated in practice, as discussed below. Geologic sequestration is the process of injecting captured CO_2 into deep subsurface rock formations for long-term storage, which includes the use of a deep saline aquifer or depleted coal seams, as well as the use of compressed CO_2 to enhance oil recovery in crude oil production operations.

Under geologic sequestration, a suitable geological formation is identified close to the proposed project, and the captured CO_2 from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet (800 meters). Below this depth, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water that already resides in the pore space would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water, and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

The U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), via the West Coast Regional Carbon Sequestration Partnership (WestCarb) has researched potential geologic storage locations including those in southern California. This information has been presented in NETL's 2010 *Carbon Sequestration Atlas of the United States and Canada*[5], NETL's National Carbon Sequestration Database and Geographic Information System (NATCARB) database[6], and Southern California Carbon Sequestration Research Consortium's (SoCalCarb) Carbon Atlas[7]. As shown in Figures 1 and 2, a number of deep saline aquifers and oil and gas reservoirs have been found to be potentially suitable for CO_2 storage. No potential for storage in depleted coal seams or basalt formations was identified.

The *Carbon Sequestration Atlas* lists the deep saline formations in Ventura and Los Angeles Basins as the "most promising" locations in southern California, and it states that "California may also be a candidate for CO_2 storage in offshore basins, although the lack of available data has limited the assessment of their CO_2 storage potential to areas where oil and gas exploration has occurred." The atlas also notes the potential for use of oil and gas reservoirs in the Los Angeles and Ventura Basins, although it states that "Reservoirs in highly fractured shales within the Santa Maria and Ventura Basins are not good candidates for CO_2 storage."

Funded via the American Recovery and Reinvestment Act, the Wilmington Graben project is an ongoing, comprehensive research program for characterization of the potential for CO_2 storage in the Pliocene and Miocene sediments offshore from Los Angeles and Long Beach. The study includes analysis of existing and new well cores, seismic studies, engineering analysis of potential pipeline systems, and risk analyses. However, no pilot studies of CO_2 injection into onshore or offshore geologic formations in the vicinity of the Amended Project site have been conducted to date.

Thermal Efficiency. Because CO_2 emissions are directly related to the quantity of fuel burned, the less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. As a means of quantifying feasible energy efficiency levels, the State of California established an emissions performance standard for California power plants. California Senate Bill 1368 limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the CEC and the CPUC. CEC regulations establish a standard for baseload generation (that is, with capacity factors in excess of 60 percent) of 1,100 pounds (or 0.55 ton) CO_2 per megawatt-hour (MWh). This emission standard corresponds to a heat rate of approximately 9,400 British thermal units per kilowatt-hour (Btu/kWh) (CEC, 2010).

In addition to the state regulations, EPA promulgated New Source Performance Standard Subpart TTTT, which includes two potentially applicable GHG emission limits for newly constructed combustion turbines. These limits are summarized below.

> Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency times its potential electric output as net-electric sales on a 3-year rolling average basis and combusts more than 90 percent natural gas on a heat input basis on a 12-operating-month rolling average basis - 450 kilograms (kg) of CO_2 per MWh of gross energy output (1,000 pounds [lb] of CO_2 per MWh); or 470 kg of CO_2 per MWh of net energy output (1,030 lb CO_2/MWh)
>
> Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency times its potential electric output or less as net-electric sales on a 3-year rolling average basis and combusts more than 90 percent natural gas on a heat input basis on a 12-operating-month rolling average basis - 50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2 per million British thermal units [MMBtu])

[5] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html

[6] http://www.netl.doe.gov/technologies/carbon_seq/natcarb/storage.html

[7] http://socalcarb.org/atlas.html

The applicable emission standard depends on whether a combustion turbine sells more electricity than its potential electrical output, which is calculated by multiplying the design efficiency and the potential electrical output, and combusts more than 90 percent natural gas. Assuming the combined-cycle power block will generate more electricity than the potential electrical output, the HBEP will need to comply with the 1,000 lb of CO_2 per MWh emission limit. The HBEP is exclusively fueled by natural gas with a combined-cycle power block design efficiency of approximately 56 percent. The HBEP's combined-cycle GHG efficiency is estimated at 766 lb of CO_2 per MWh (net), assuming an 8 percent performance degradation (see Attachment 1), which clearly complies with Subpart TTTT's emission limit of 1,000 lb of CO_2 per MWh.

The HBEP simple-cycle power block design efficiency is 41 percent and the potential HBEP simple-cycle power block's electrical output threshold is 718,320 MWh-Net (based on the design efficiency of 41 percent and the net electrical output of 200 MW for 8,760 hours per year). The HBEP simple-cycle power block's potential annual net electric sales are 258,924 MWh-Net, assuming 200 MWs-Net of generation and 1,284 hours per year of operation (1,150 operating hours plus 58 startup and 76 shutdown hours). Since the annual net electric sales are less than the electric output threshold, the HBEP simple-cycle power block must comply with Subpart TTTT emission limit of 50 kg CO_2 per GJ of heat input (120 lb CO_2/MMBtu). As a natural-gas fired facility, the HBEP is expected to emit CO_2 at a rate of 117 lb CO_2/MMBtu, thereby complying with the applicable emission limit in Subpart TTTT.

The HBEP is a highly efficient multiple-staged generator project that incorporates a high degree of turndown, fast start, and ramping capability that will support grid reliability as renewable generating sources comprise a larger share of California's energy production. This allows an increased use of wind power and other renewable energy sources, with backup power available from the HBEP. A natural-gas-fired plant such as the HBEP uses a relatively small amount of electricity to operate the facility compared to the energy in the fossil fuel combusted. Therefore, minimal benefit occurs in terms of energy efficiency and GHG emission reductions of the facility associated with lowering electricity usage at the facility compared to increasing the thermal efficiency of the process.

The addition of the high thermal efficiency of the HBEP's generation to the state's electricity system will facilitate the integration of renewable resources in California's generation supply and will displace other less-efficient, higher GHG-emitting generation.

California's Renewable Portfolio Standard (RPS) requirement was increased from 20 percent by 2010 to 33 percent by 2020, with the adoption of Senate Bill 2 on April 12, 2011. To meet the new RPS requirements, the amount of dispatchable, high-efficiency, natural gas generation used as regulation resources, fast-ramping resources, or load-following or supplemental energy dispatches will have to be significantly increased. Additionally, Senate Bill 350 will increase the RPS requirements to 50 percent by 2030. The HBEP will aid in the effort to meet California's aggressive RPS standard, because a significant attribute of the HBEP is that the combined- and simple-cycle facility can operate similarly to a peaking plant but at higher thermal efficiency.

Based on design, the HBEP will allow a rapid startup of the combustion turbines, with the combined-cycle combustion turbines capable of achieving full load operation within 15 minutes of initiating a startup (with the exception of the 24 cold starts for the combined-cycle turbines). The simple-cycle power block can achieve full load operation within 10 minutes of initiating a startup. The maximum electrical load ramp rate is 10 percent per minute when operating at the minimum operating rate.

In summary, using the GE Frame 7FA.05 and LMS-100PB turbines allows the project goals to be met, while maintaining a higher efficiency than comparable combustion turbine applications. The ability to produce fast-ramping power to augment renewable power sources to the grid make the HBEP a highly energy-efficient system.

3.2.2.2 Eliminate Technically Infeasible Options – Step 2

The second step for the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to assess its technical feasibility. The technology is feasible only when it is available and applicable. A technology that is not commercially available for the scale of the project was considered infeasible. An available technology is considered applicable only if it can be reasonably installed and operated on the proposed project.

Carbon Capture and Storage. Although many believe that CCS will allow the future use of fossil fuels while minimizing GHG emissions, there are a number of technical barriers concerning the use of this technology for the HBEP, as follows:

- No full-scale systems for solvent-based carbon capture are currently in operation to capture CO_2 from dilute exhaust steams such as those from natural-gas-fired electrical generation systems at the scale proposed for the Amended HEBP.
- Use of captured CO_2 for enhanced oil recovery (EOR) is widely believed to represent the practical first opportunity for CCS deployment; however, identification of suitable oil reservoirs with the necessary willing and able owners and operators is not feasible for the HBEP to undertake. Oil and gas production in the vicinity of the HBEP is available for EOR; however, only pilot-scale projects are known in the region and only estimates are available on the capacity of these miscible oil fields.
- Little experience exists with other types of storage systems, such as deep saline aquifers (geological sequestration) or ocean systems (ocean sequestration). These storage systems are not commercially available technology.
- Because of the developmental nature of CCS technology, vendors and contractors do not provide turn-key offerings; separate contracting would be required for capture system design and construction; compression and pipeline system routing, siting and licensing, engineering and construction; and geologic storage system design, deployment, operations, and monitoring. Because no individual facility could be expected to take on all of these requirements to implement a control technology, this demonstrates that the technology as a whole is not yet commercially available.
- Significant legal uncertainties continue to exist regarding relationship between land surface ownership rights and subsurface (pore space) ownership, and potential conflicts with other uses of land such as exploitation of mineral rights, management of risks and liabilities, and so on.
- The potential for frequent startup and shutdown, as well as intended rapid load fluctuations, of generation units at the HBEP facility makes CCS impractical for two reasons – inability of capture systems to startup in the same short time frame as combustion turbines, and infeasibility for potential users of the CO_2 such as EOR systems to use uncertain and intermittent flows. As described above, the units at the HBEP facility are designed to accommodate rapidly fluctuating power and steam demands from renewable electrical generation sources.

These issues are discussed in more detail below.

FIGURE 1
United States and Canadian Saline Formations
AES Huntington Beach Energy Project
Huntington Beach, California

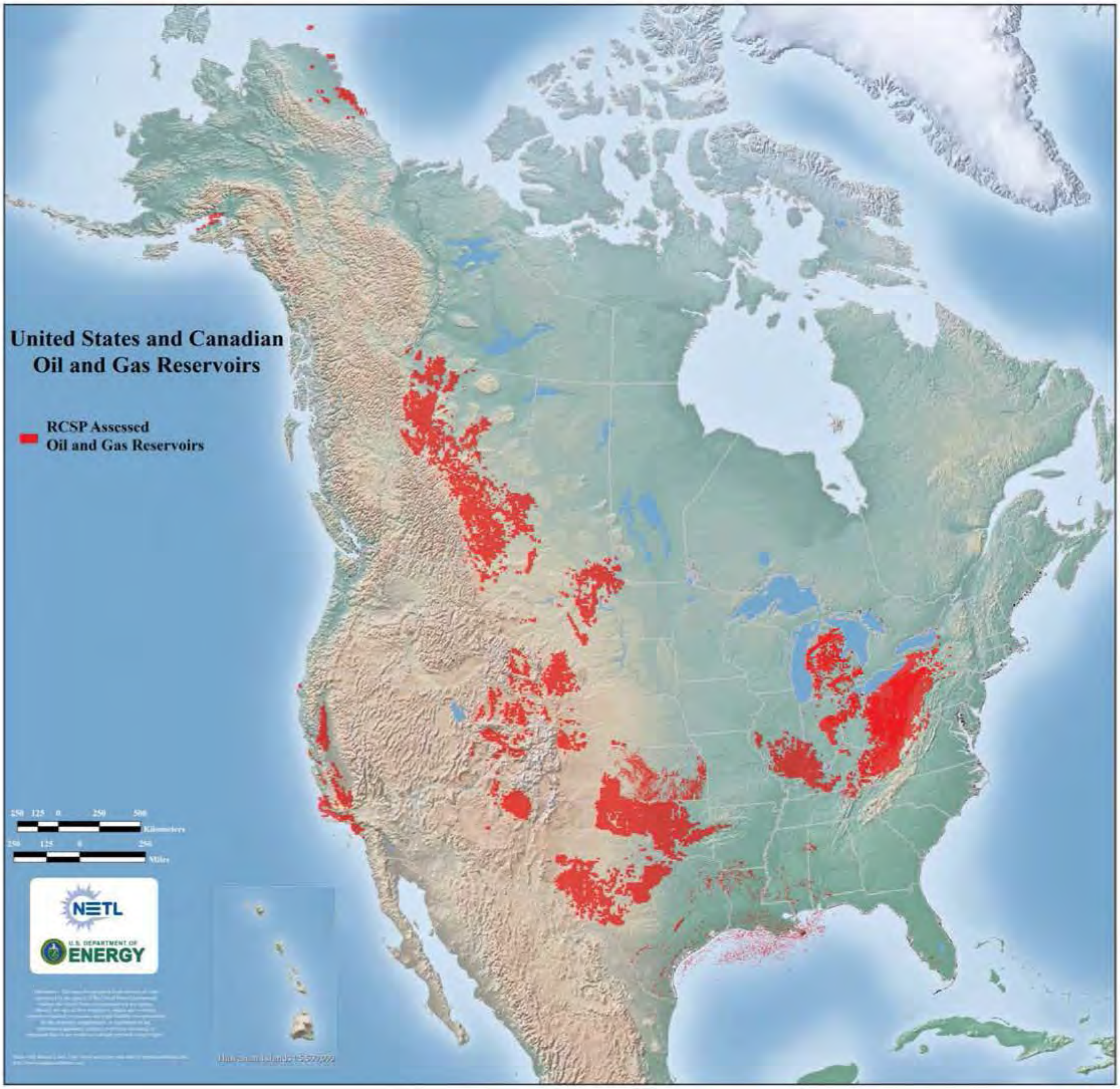


FIGURE 2
United States and Canadian Oil and Gas Reservoirs
AES Huntington Beach Energy Project
Huntington Beach, California

CH2MHILL.

As suggested in EPA's *New Source Review Workshop Manual*, control technologies should be demonstrated in practice on full-scale operations to be considered available within a BACT analysis: "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice" (EPA, 1990). As discussed in more detail below, carbon capture technology has not been demonstrated in practice in power plant applications. Other process industries do have carbon capture systems that are demonstrated in practice; however, the technology used for these processes cannot be applied to power plants at the scale of the HBEP.

Three fundamental types of carbon capture systems are employed throughout various process and energy industries: sorbent adsorption, physical absorption, and chemical absorption. Use of carbon capture systems on power plant exhaust is inherently different from other commercial-scale systems currently in operation, mainly because of the concentration of CO_2 and other constituents in the gas streams.

For example, CO_2 is separated from petroleum in refinery hydrogen plants in a number of locations, but this is typically accomplished on the product gas from a steam CH_4 reforming process that contains primarily hydrogen (H_2), unreacted CH_4, and CO_2. Based on the stoichiometry of the reforming process, the CO_2 concentration is approximately 80 percent by weight, and the gas pressure is approximately 350 pounds of force per square inch gauge (psig). Because of the high concentration and high pressure, a pressure swing adsorption (PSA) process is used for the separation. In the PSA process, all non-hydrogen components, including CO_2 and CH_4, are adsorbed onto the solid media under high pressure; after the sorbent becomes saturated, the pressure is reduced to near atmospheric conditions to desorb these components. The CO_2/CH_4 mixture in the PSA tail gas is then typically recycled to the reformer process boilers to recover the heating value; however, where the CO_2 is to be sold, an additional amine absorption process would be required to separate the CO_2 from CH_4. In its May 2011 *DOE/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update*, NETL notes the different applications for chemical solvent absorption, physical solvent absorption, and sorbent adsorption processes. As noted in Section 4.B, "When the fluid component has a high concentration in the feed stream (for example, 10 percent or more), a PSA mechanism is more appropriate" (NETL, 2011).

In another example, at the Dakota Gasification Company's Great Plains Synfuels Plant in North Dakota, CO_2 is separated from intermediate fuel streams produced from gasification of coal. The gas from which the CO_2 is separated is a mixture of primarily H_2, CH_4, and 30 to 35 percent CO_2; a physical absorption process (Rectisol) is used. In contrast, as noted on page 29 of the *Report of the Interagency Task Force on Carbon Capture and Storage* (DOE and EPA, 2010), CO_2 concentrations for natural-gas-fired systems are in the range of 3 to 5 percent. This adds significant technical challenges to separation of CO_2 from natural-gas-fired power plant exhaust as compared to other systems.

In Section 4.A of the above-referenced technology update, NETL notes this difference between pre-combustion CO_2 capture, such as that from the North Dakota plant, versus the post-combustion capture, such as that required from a natural-gas-fired power plant: "Physical solvents are well suited for pre-combustion capture of CO_2 from syngas at elevated pressures; whereas, chemical solvents are more attractive for CO_2 capture from dilute low-pressure post-combustion flue gas" (NETL, 2011).

In the 2010 report noted above, the task force discusses four currently operating post-combustion CO_2 capture systems associated with power production. All four are on coal-based power plants where CO_2 concentrations are higher (typically 12 to 15 percent), with none noted for natural gas-based power plants (typically 3 to 5 percent).

The DOE/NETL is a key player in the nation's efforts to realize commercial deployment of CCS technology. A downloadable database of worldwide CCS projects is available on the NETL website[8]. Filtering this database for projects that involve both capture and storage, which are based on post-combustion capture technology (the only technology applicable to natural gas turbine systems) and are shown as "active" with "injection ongoing" or "plant in operation," yields four projects. Three projects, one of which is a pilot-scale process noted in the interagency task force report as described above, are listed at a capacity of 274 tons per day (100,000 tpy), and

[8] http://www.netl.doe.gov/technologies/carbon_seq/global/database/index.html

the fourth has a capacity of only 50 tons per day. Post-combustion CCS has not been accomplished on a scale of the Amended HEBP facility. Furthermore, scale-up involving a substantial increase in size from pilot scale to commercial scale is unusual in chemical processes and would represent significant technical risk.

A chemical solvent CCS approach would be required to capture the approximate 3 to 5 percent CO_2 emitted from the flue gas generated from the natural-gas-fired systems (combined-cycle) used at the Amended HEPB facility. To date, a chemical solvent technology has not been demonstrated at the operating scale proposed.

As detailed in the August 2010 report, one goal of the task force is to bring 5 to 10 commercial demonstration projects online by 2016. With demonstration projects still years away, clearly the technology is not currently commercially available at the scale necessary to operate the Amended HEBP facility. It is notable that several projects, including those with DOE funding or loan guarantees, were cancelled in 2011, making it further unlikely that technical information required to scale up these processes can be accomplished in the near future. For example, the AEP Mountaineer site (AEP; a former DOE demonstration commercial-scale project) was to expand capture capacity to 100,000 tpy; however, to date only the "Project Validation Facility" was completed and only accomplished capture of a total of 50,000 metric tons and storage of 37,000 metric tons of CO_2. AEP recently announced that the larger project will be cancelled after completion of the front-end engineering design because of uncertain economic and policy conditions.

EPA's Fact Sheet and Ambient Air Quality Impact Report for the Palmdale project states that "commercial CO_2 recovery plants have been in existence since the late 1970s, with at least one plant capturing CO_2 from gas turbines". However, on review of the fact sheet referenced for the gas turbine project[9], it is notable that the referenced project is not a commercial-scale operation; rather, it is a pilot study at a commercial power plant. The pilot system captured 365 tons per day of CO_2 from the power plant, in the range of the power pilot tests noted above. Full-scale capture of power plant CO_2 has not yet been accomplished anywhere in the world.

The interagency task force report notes the lack of demonstration in practice:

> *Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.* (DOE and EPA, 2010)

The ability to inject into deep saline aquifers as an alternative to EOR reservoirs is a major focus of the NETL research program. Although it is believed that saline aquifers are a viable opportunity, there are many uncertainties. Risk of mobilization of natural elements such as manganese, cobalt, nickel, iron, uranium, and barium into potable aquifers is of concern. Technical considerations for site selection include geologic siting, monitoring and verification programs, post-injection site care, long-term stewardship, property rights, and other issues.

At least one planned saline aquifer pilot project is underway in the Lower San Joaquin Valley near Bakersfield, California (the Kimberlina Saline Formation), that may act as a possible candidate location for geologic sequestration and storage. According to WestCarb, a pilot project plant operated by Clean Energy Systems is targeting the Vedder Sandstone formation at a depth of approximately 8,000 feet, where there is a beaded stream unit of saline formation that may be favorable for CO_2 storage. It is unclear when the project is planned for full scale testing, and no plans are currently available to build a pipeline within the area to transport CO_2 to the test site. As noted above, the Wilmington Graben project is a large-scale study of the potential for geologic storage in offshore formations near Los Angeles; however, no indications of near-term plans for pilot testing were noted in NETL or SoCalCarb's websites.

9 http://www.powermag.com/coal/2064.html

As noted above, presumably the CO_2 could be used for EOR applications within the Los Angeles and Ventura Basins, but the exact location, time frame, and needed flow rates for those existing or future EORs are unclear because this information is typically treated as being a trade secret. During a study to evaluate the "future oil recovery potential in the major oil basins and large oil fields in California," the DOE concluded that a number of oil fields in the Los Angeles Basin are "amendable to miscible CO_2-EOR." Two of those oil fields, the Santa Fe Springs and Dominquez fields, are located approximately 30 miles from the Amended HEBP facility. However, the feasibility of obtaining the necessary permits to build infrastructure and a pipeline to transport CO_2 to these fields through a densely urbanized area is uncertain.

Figure 3 from the Interagency Task Force report shows that no existing CO_2 pipelines are shown in California. The report does note that nationally there are "many smaller pipelines connecting sources with specific customers"; however, based on lack of natural or captured CO_2 sources in southern California, it is assumed that no pipelines exist. The SoCalCarb carbon atlas shows a number of existing pipelines in the region; however, these are petroleum product pipelines. As noted above, because of high pressures, potential for propagation facture, and other issues, CO_2 pipeline design is highly specialized, and product pipelines would not be suitable for re-use of CO_2 transport.

Regarding CO_2 storage security, the CCS task force report (DOE and EPA, 2010) notes such uncertainties:

> *"The technical community believes that many aspects of the science related to geologic storage security are relatively well understood. For example, the Intergovernmental Panel on Climate Change (IPCC) concluded that "it is considered likely that 99 percent or more of the injected CO_2 will be retained for 1,000 years" (IPCC, 2005). However, additional information (including data from large-scale field projects, such as the Kimberlina project, with comprehensive monitoring) is needed to confirm predictions of the behavior of natural systems in response to introduced CO_2 and to quantify rates for long-term processes that contribute to trapping and, therefore, risk profiles (IPCC, 2005). "*

Field data from the Kimberlina CCS pilot project will provide additional information regarding storage security for that and other locations. Meanwhile, some uncertainties will remain regarding safety and permanence aspects of storage in these types of formations.

The effectiveness of ocean sequestration as a full-scale method for CO_2 capture and storage is unclear given the limited availability of injection pilot tests and the ecological impacts to shallow and deep ocean ecosystems. Ocean sequestration is conducted by injecting supercritical liquid CO_2 from either a stationary or towed pipeline at targeted depth interval, typically below 3,000 feet. CO_2 is injected below the thermocline, creating either a rising droplet or a dense phase plume and sinking bottom gravity current. Through NETL, extensive research is being conducted by the Monterey Bay Aquarium Research Institute on the behavior of CO_2 hydrates and dispersion of these hydrates within the various depth horizons of the marine environment; however, the experiments are small in scale and the results may not be applicable to larger-scale injection projects in the near future. Long-term effects on the marine environment, including pH excursions, are ongoing, making the use of ocean sequestration technically infeasible at the current time. The feasibility of implementing a commercially available sequestration approach is further brought into question, with the IPCC stating:

> *Ocean storage, however, is in the research phase and will not retain CO_2 permanently as the CO_2 will re-equilibrate with the atmosphere over the course of several centuries...Before the option of ocean injection can be deployed, significant research is needed into its potential biological impacts to clarify the nature and scope of environmental consequences, especially in the longer term...Clarification of the nature and scope of long-term environmental consequences of ocean storage requires further research.* (IPCC, 2005).

Questions may also arise regarding the international legal implications of injecting industrial generated CO_2 into the ocean, which may eventually migrate to other international waters.

CCS technology development is dominated by vendors that are attempting to commercialize carbon capture technologies and by academia-led teams (largely funded by DOE) that are leading research into the geologic systems. The ability for electric utilities to contract for turn-key CCS systems simply does not exist at this time.

Most current carbon capture systems are based on amine or chilled ammonia technology, which are chemical absorption processes. Although capture system startup and shutdown time of vendor processes could not be confirmed within this BACT analysis, clearly both types of processes would require durations that exceed the time required for the HBEP turbine startup or load response. As described above, the Amended HEBP may start or stop turbines, and it may adjust the load on the operating turbines rapidly to meet grid reliability demands. In contrast, both amine and chilled ammonia systems require startup of countercurrent liquid-gas absorption towers and either chilling of the ammonia solution or heating of regeneration columns for the amine systems. It is technically infeasible for the carbon capture systems to startup and shut down or to make large adjustments in gas volume in the time frames required to serve this type of operation effectively; this means that portions of the HBEP operation would run without CO_2 capture even with implementation of a CCS system. Alternatively, the CCS system could be operated at a minimum load during periods of expected operation. However, this approach would consume energy, offsetting some of the benefit.

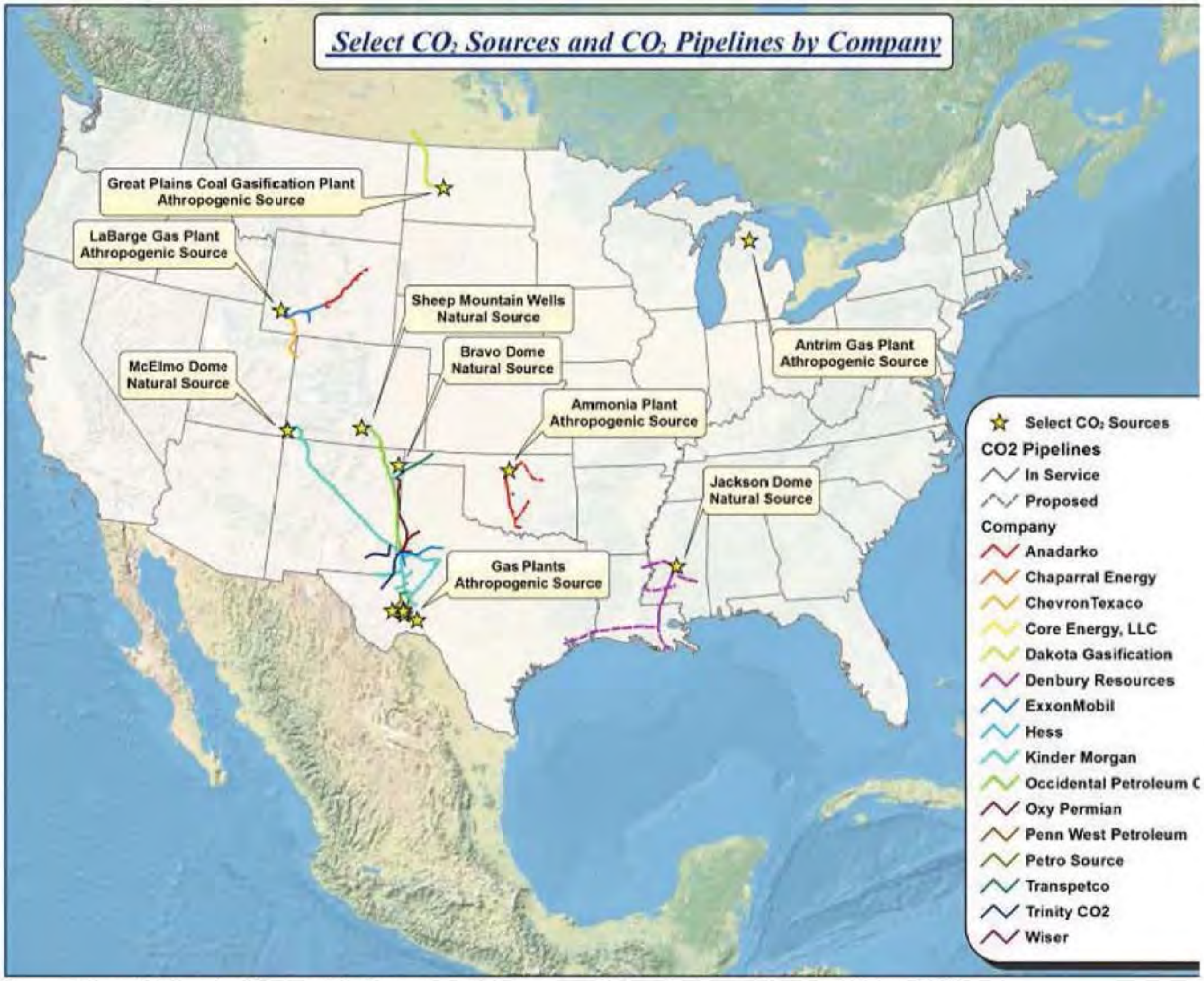
Finally, the potential to sell CO_2 to industrial or oil and gas operations is infeasible for an operation such as this, where daily operation of the HBEP depends on grid dispatch needs, particularly to offset reductions from renewable energy sources. Even if a potential EOR opportunity could be identified, such an operation would typically need a steady supply of CO_2. Intermittent CO_2 supply from potentially short duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable. Therefore, CCS technology would be better suited for applications with low variability in operating conditions.

In the EPA PSD and Title V GHG Permitting Guidance, the issues noted above are summarized: "A number of ongoing research, development, and demonstration projects may make CCS technologies more widely applicable *in the future*" (EPA, 2011b; italics added). From page 36 of this guidance, it is noted:

> *While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard.* (EPA, 2011b)

The CCS alternative is not considered technically feasible for the Amended HEBP, and it should therefore be eliminated from further consideration in Step 2. However, at the suggestion of EPA team members on other recent projects, economic feasibility issues will be discussed in Step 4.

Thermal Efficiency. Thermal efficiency is a standard measurement metric for combined-cycle facilities; therefore, it is technically feasible as a control technology for BACT consideration.



Source: Figure B-1 from the "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010.

FIGURE 3
Existing and Planned CO2 Pipelines in the United States with Sources
AES Huntington Beach Energy Project
Huntington Beach, California

CH2MHILL.

3.2.2.3 Combustion Turbine GHG Control Technology Ranking – Step 3

Because CCS is not technically feasible, the only remaining technically feasible GHG control technology for the Amended HEBP is thermal efficiency. While CCS will be discussed further in Step 4, and if it were technically feasible would rank higher than thermal efficiency for GHG control, thermal efficiency is the only technically feasible control technology that is commercially available and applicable for the Amended HEBP.

3.2.2.4 Evaluate Most Effective Controls – Step 4

Step 4 of the BACT analysis is to evaluate the remaining technically feasible controls and consider whether energy, environmental, and/or economic impacts associated with the remaining control technologies would justify selection of a less-effective control technology. The top-down approach specifies that the evaluation begin with the most-effective technology.

Carbon Capture and Sequestration. As demonstrated in Step 2, CCS is not a technically feasible alternative for the the Amended HEBP. Nonetheless, at the suggestion of the EPA team members on other recent projects, economic feasibility of CCS technology is reviewed in this step. Control options considered in this step therefore include application of CCS technology and plant energy thermal efficiency. As demonstrated below, CCS is clearly not economically feasible for the Amended HEBP.

On page 42 of the EPA PSD and Title V Permitting Guidance, it is suggested that detailed cost estimates and vendor quotes should not be required where it can be determined from a qualitative standpoint that a control strategy would not be cost effective:

> *With respect to the valuation of the economic impacts of [AES] control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system.* (EPA, 2011b)

The guidance document also acknowledges the current high costs of CCS technology:

> *EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the technical feasibility of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the economical feasibility of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.*(EPA, 2011b)

The costs of constructing and operating CCS technology are indeed extraordinarily high, based on current technology. Even with the optimistic assumption that appropriate EOR opportunities could be identified in order to lower costs, compared to "pure" sequestration in deep saline aquifers, or through deep ocean storage, additional costs to the HBEP would include the following:

- Licensing of scrubber technology and construction of carbon capture systems
- Significant reduction to plant output due to the high energy consumption of capture and compression systems
- Identification of oil and gas companies holding depleted oil reservoirs with appropriate characteristics for effective use of CO_2 for tertiary oil recovery, and negotiation with those parties for long-term contracts for CO_2 purchases
- Construction of compression systems and pipelines to deliver CO_2 to EOR or storage locations
- Hiring of labor to operate, maintain, and monitor the capture, compression, and transport systems

- Resolving issues regarding project risk that would jeopardize the ability to finance construction

The interagency task force report provides an estimate of capital and operating costs for carbon capture from natural gas systems: "For a [550-MWe net output] NGCC plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture" (DOE and EPA, 2010). Using the "Capacity Factor Method" for prorating capital costs for similar systems of different sizes as suggested by the Association for the Advancement of Cost Engineering and other organizations, the CO_2 capture system capital cost for the Amended HEBP is estimated as at least $467 million. Based on an estimated HBEP capital cost of $770 million to $880 million for the plant and equipment, the capture system alone would add approximately 50 percent to the cost of the overall plant equipment capital cost.

As noted above, the effort required to identify and negotiate with oil and gas companies that may be able to utilize the CO_2 would be substantial. Prospective EOR oil fields are located within the area, but no active commercial facilities exist within the Los Angeles Basin, making predictions for CO_2 demand generated by CCS difficult. And, because of the patchwork of oil well ownership, many parties could potentially be involved in negotiations over CO_2 value.

Because of the extremely high pressures required to transport and inject CO_2 under supercritical conditions, the compressors required are highly specialized. For example, the compressors for the Dakota Gasification Company system are of a unique eight-stage design. It is unclear whether the Task Force natural gas combined-cycle (NGCC) cost estimate noted above includes the required compression systems; if not, then this represents another substantial capital cost.

Pipelines must be designed to withstand the very high pressures (over 2,000 psig) and the potential for corrosion if any water is introduced into the system. As noted above, if CCS were otherwise technically and economically feasible for the Amended HEBP, the most realistic scenario could be to construct a pipeline from the Huntington Beach area to either the Santa Fe Springs or Dominquez oil fields near Los Angeles for EOR, assuming that permits and right-of-way agreements are obtained and there is an active EOR operation in this location. As noted above, the approximate distance of the pipeline to either of these two fields is approximately 30 miles. Based on engineering analysis by the designers of the Denbury CO_2 pipeline in Wyoming, costs for an 8-inch CO_2 pipeline are estimated at $600,000 per mile, for a total cost of $18 million. Therefore, the pipeline alone would represent an additional 3 percent increase to the capital cost assuming that the EOR opportunities could be realized; however, costs could be substantially higher to transport CO_2 to deep saline aquifer or ocean storage locations.

It is unlikely that financing could be approved for a project that combines CCS with generation, given the technical and financial risks. Also, as evidenced with utilities' inability to obtain CPUC approval for integrated gasification / combined-cycle projects because of their unacceptable cost and risk to ratepayers (such as Wisconsin's disapproval of the Wisconsin Electric Energy project), it is reasonable to assume that the same issues would apply in this case before the CEC.

In summary, capital costs for capture system and pipeline construction alone would almost double the project capital cost, and lost power sales resulting from the CCS system energy penalty would represent another major impact to the project financials and a multi-fold increase to project capital costs. Other costs, such as identification, negotiation, permitting studies, and engineering of EOR opportunities; operating labor and maintenance costs for capture, compression, and pipeline systems; uncertain financing terms or inability to finance; and difficulty in obtaining CEC approval would also impact the project also, it is unclear whether compression systems are included in the task force estimate of capture system costs. Not only is CCS not technically feasible at this Amended Project scale, as the above discussion demonstrates, but CCS is clearly not economically feasible for natural-gas-fired turbines at this time.

Thermal Efficiency. A search of the EPA's RACT/BACT/LAER Clearinghouse was performed for NGCC projects. GHG permit information was found for one source—Westlake Vinyls Company LP Cogeneration Plant (LA-0256)—which was issued a permit in December 2011. The record for this source includes only hourly and annual CO_2e emission limitations and no information of costs estimated performed for the GHG BACT determination. Recent GHG determinations were completed for the Russell City Energy Center and the Palmdale Hybrid Power Project in

California. Both projects proposed the use of combined-cycle configurations to produce commercial power, and the BACT analyses for both projects concluded that plant efficiency was the only feasible combustion control technology. However, the Palmdale project includes a 251-acre solar thermal field that generates up to 50 MWs during sunny days, which reduces the project's overall heat rate.

Because CCS is not technically or economically feasible, thermal efficiency remains the most effective, technically feasible, and economically feasible GHG control technology for the HBEP. The operationally flexible turbine class and steam cycle designs selected for the HBEP are the most thermally efficient for the project design objectives, operating at the projected annual capacity factor of approximately 40 percent. Table 3-1 compares the HBEP heat rate with that of other recent combined- and simple-cycle projects permitted in California.

TABLE 3-1
Comparison of Heat Rates and GHG Performance Values of Recently Permitted Projects

Plant Performance Variable	Heat Rate (Btu/kWh)	GHG Performance ($MTCO_2/MWh$)
Amended Huntington Beach Energy Project	6,322 – Combined-cycle 9,074 – Simple-cycle [a]	0.379 [a]
Watson Cogeneration Project [b]	5,027 to 6,327	0.219 to 0.318
Palmdale Hybrid Power Project	6,970 [c]	0.370 [c]
Russell City Energy Project	6,852 [d]	0.371 [e]
El Segundo Power Redevelopment Project	6,754 – Combined-cycle 8,458 – Simple-cycle [f]	0.409
Carlsbad Energy Center [g]	9,473	0.503

[a] The net heat rate at 65.8°F at site elevation, relative humidity of 58.32 percent, no inlet air cooling,. Heat rates averaged over the operating range of 50 to 100 percent load, with heat rates at higher load rates being more efficient. GHG performance based on plant-wide CO_2 emissions of 1,720,623 metric tons CO_2/year / (644 MWs * 6,612 hours/year + 200 MWs * 1,401 hours/year).

[b] From Watson Cogeneration Project Commission Final Decision.

[c] From Tables 3 and 4 of the Palmdale Hybrid Power Project Greenhouse Gas BACT Analysis (AECOM, 2011).

[d] Net design heat rate with no duct burners, from "GHG BACT Analysis Case Study, Russell City Energy Center; November 2009, updated February 3, 2010."

[e] From Russell City total heat input of 4,477 MMBtu/hr (from PSD Permit), generation of 653 MW was calculated utilizing design heat rate of 6,852 Btu/kWh. From reference document in footnote d above, 1-hour CO_2 limit is 242 $MTCO_2$/hr, which yields 0.371 MT CO_2/MWh.

[f] From El Segundo Power Redevelopment Project Revised Final Determination of Compliance, pages 9 and 11, July 9, 2015 (TN 205313-2).

[g] From Carlsbad Energy Center Project Amendments Final Decision, Greenhouse Gas Table 3, page 6.1-14, August 3, 2015 (TN 205625).

Note:

$MTCO_2$/MWh = metric tons of carbon dioxide per megawatt-hour

As shown in Table 3-1, when comparing the HBEP heat rate and GHG performance values for other recently permitted California facilities, the HBEP heat rate is consistent with these other recent projects. For instance, comparing the HBEP overall plant efficiency to the Carlsbad project shows the benefits of the HBEP's more efficient combined-cycle power block.

The HBEP offers the flexibility of fast start and ramping capability of both combined- and simple-cycle configurations, as well as the high efficiency associated with the combined-cycle power block. Comparing the thermal efficiency of the HBEP to other recently permitted California projects demonstrates that the HBEP's thermal efficiency is consistent with other projects and the HBEP thermal efficiency is proposed as BACT for GHGs.

3.2.2.5 GHG BACT Selection – Step 5

Based on the above analysis, the only remaining feasible and cost-effective option is the "Thermal Efficiency" option, which therefore is selected as the BACT.

As shown above, the GE Frame 7FA.05 and LMS-100PB combustion turbines operating as combined-cycle and simple-cycle power blocks compare favorably with other comparable turbines. The HBEP turbines will combust natural gas to generate electricity from both the CTGs and STG. Therefore, the thermal efficiency for the Amended Project is best measured in terms of lb of CO_2 per MWh.

The performance of all CTGs degrades over time. Typically, turbine degradation at the time of recommended routine maintenance is up to 8 percent. Additionally, thermal efficiency can vary significantly with combustion turbine turndown and steam turbine/duct burning combinations. Finally, annual metrics for output-based limits on GHG emissions are affected by startup and shutdown periods because fuel is combusted before useful output of energy or steam. Therefore, the annual average thermal efficiency performance of any turbine will be greater than the optimal efficiency of a new turbine operating continuously at peak load over the lifetime of the turbine.

Based on the projected annual operating profile and equipment design specification provided by AES, the GHG BACT calculation for the HBEP was determined in lb of CO_2 per MWh of energy output (on a gross basis). Included in this calculation is the inherent degradation in turbine performance over the lifetime of the HBEP. The HBEP proposed BACT level for GHG emissions is an emission rate of 836 lb CO_2/MWh of net energy output[10].

[10] 1,720,623 metric tons of CO2/year / 4,538,328 MWh (644 MWs * 6,612 hours/year + 200 MW * 1,401 hours/year) * 2204.62 lb/metric tons

SECTION 4

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Attachment 2
Huntington Beach Energy Project Air Permit Application Documentation

Report

Huntington Beach Energy Project Air Permit Application Documentation

Applicant

AES North America Development, LLC

October 2015

Prepared by

CH2MHILL®

Contents

SECTION 1
Background

The Huntington Beach Energy Project (HBEP) is a proposed 844-megawatt (MW) nominal power plant to be located at the existing site of the Huntington Beach Generating Station, situated approximately 900 feet from the Pacific Ocean. The surrounding area is a mix of residential, wetland preserve, public beach, and industrial land uses, and is bordered by a manufactured home/recreation vehicle park on the west, Huntington Beach Channel and residential areas to the north and east, a tank farm to the north, the Huntington Beach Wetland Preserve/Magnolia Marsh wetlands on the southeast, and the Huntington Beach State Park and Pacific Ocean to the south and southwest. The entire parcel on which the Huntington Beach Generating Station is located, including the switchyard and tank farm, is approximately 106 acres, and the new plant will be constructed on about 28.6 of those acres. The nearest inhabitants to the proposed project site are in a residential area approximately 300 to 400 feet west of the site.

The current Huntington Beach Generating Station consists of two utility boilers. Boilers 1 and 2 are identical units, each rated at 215 MW output and 2,021 million British thermal units per hour (MMBtu/hr) heat input. The boilers are equipped with selective catalytic reduction (SCR) systems, and are fired exclusively on natural gas. The boilers were built in the 1950s. There are two 275-horsepower (hp) diesel-fueled emergency engines, which were installed in 2001 for fire control, a 30,000-gallon urea storage tank, and two urea-to-ammonia converters. The urea is used in the SCR systems, and is converted into ammonia before injection into the boiler exhaust with the use of the urea-ammonia converters. There is also an old peaker turbine (Unit 5) that has been shut down and no longer operates, as well as Boilers 3 and 4, which have also been shut down.

The current ownership of the equipment at the site is split between AES Huntington Beach, LLC (AES), which owns Boilers 1 and 2, the two emergency engines, and the urea storage tank, and Edison Mission Energy, LLC, which purchased Boilers 3 and 4 and permanently retired them in November 2012. AES is the operator for all the equipment onsite. Boilers 1 and 2, along with their SCR systems, urea storage tank, and urea-to-ammonia converters will be shut down concurrent with the combined-cycle power block coming online.

As part of this project, AES has also proposed to shut down Boiler 7, rated at 4,752.2 MMBtu/hr heat input and 480 MW output, at the AES Redondo Beach Generating Station. Therefore, the total generating capacity being retired as part of this project is 910 MW.

The proposed new facility will consist of two power blocks (one combined-cycle and one simple-cycle) capable of producing a nominal power output of 844 MW net. The combined-cycle power block will consist of two combustion turbine generators (CTG), two heat recovery steam generators (HRSG) without duct firing, one steam turbine generator (STG), a natural-gas-fired auxiliary boiler, and auxiliary equipment including an aqueous ammonia storage tank and an oil/water separator. The simple-cycle power block will consist of two CTGs and auxiliary equipment including an aqueous ammonia storage tank and an oil/water separator. AES, a wholly-owned subsidiary of AES Southland Corp., will be the facility owner and operator of the new plant.

The plant will be designed to supply power to the wholesale energy market through the existing substation, located adjacent and to the northeast of the property. Output will depend on market conditions and dispatch requirements. The plant's expected availability is over 98 percent on an annual basis, with the actual capacity factor anticipated to be between 45 and 75 percent. AES expects the plant to be dispatched at peaking and intermediate loads on a regular basis. Therefore, the plant is designed to have the ability to start quickly – cold starts should be 60 minutes for the combined-cycle power block and 30 minutes for the simple-cycle power block – and can operate with only one turbine online at any given time.

The HBEP requires a significant revision to the existing Title V permit at the AES, Huntington Beach site (Facility ID# 115389). The new project is also subject to the oxides of nitrogen (NO_x) and oxides of sulfur (SO_x) Regional Clean Air Incentives Market (RECLAIM) and Prevention of Significant Deterioration (PSD) regulations for nitrogen dioxide (NO_2), carbon monoxide (CO), greenhouse gases (GHG), and particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}).

Construction of the combined-cycle power block is scheduled to begin in the second quarter of 2017 and end in the second quarter of 2020. Construction of the simple-cycle power block is scheduled to begin in the second quarter of 2022 and end in the fourth quarter of 2023.

SECTION 2

Process Description for Combustion Turbines

The gas turbine facility will consist of two combined-cycle and two simple-cycle combustion turbines. The combined-cycle power block will consist of two General Electric (GE) Frame 7FA.05 CTGs, each rated at 231.2 MW (International Organization for Standardization [ISO] gross) and equipped with dry low NO_x combustors, evaporative inlet air cooling, an SCR, and an oxidation catalyst, two HRSGs, and an STG rated at 230.9 MW (ISO gross). The combined-cycle power block will include a Rentech, model D-Type water tube auxiliary boiler rated at 71 MMBtu/hr, higher heating value (HHV) basis, with a single John Zink/Coen RMB low NO_x burner. The auxiliary boiler will also include an SCR and flue-gas recirculation emission controls. Other ancillary equipment includes an ammonia storage tank and an oil/water separator. The combined-cycle CTG exhaust stacks will be 150 feet tall and the auxiliary boiler exhaust stack will be 80 feet tall.

The simple-cycle power block will consist of two GE LMS-100PB CTGs, each rated at 100.8 MW (average ambient temperature gross) and equipped with dry low NO_x combustors, evaporative inlet air-cooling, an SCR, and an oxidation catalyst, an ammonia storage tank, and an oil/water separator. The simple-cycle CTG exhaust stacks will be 80 feet tall.

Each power block is independently operated.

The system output will vary depending on the ambient air temperature condition, use of evaporative coolers, amount of auxiliary load, generator power factor, and other factors. At the site's low temperature (maximum output case), the plant total output is restricted to 894.4 MW (693.6 MW for the combined-cycle CTGs and 200.8 MW for the simple-cycle CTGs). Table 2-1 presents the combined-cycle output on a per turbine basis. Table 2-2 presents the simple-cycle output on a per turbine basis.

TABLE 2-1
Combined-Cycle Output Per Turbine

	ISO 59°F – 60% RH (Evaporative Cooling Off)	110°F – 8% RH (Evaporative Cooling On)	32°F – 87% RH (Evaporative Cooling Off)	66°F – 58% RH Evaporative Cooling On)
Gas Turbine Heat Input, MMBtu/hr, HHV	2,240	2,123	2,273	2,248
Gas Turbine Gross Output[a], kW	231,197	215,890	236,140	232,073
Steam Turbine Gross Output[b], kW	115,470	96,702	110,675	114,838
Total Gross Power Output[c], kW	346,667	312,592	346,815	346,911
Net Power Output, kW	339,875	318,160	340,745	340,840
Net Plant Heat Rate, Btu/kWh, LHV	5,967	6,271	6,017	5,984
Net Plant Heat Rate, Btu/kWh, HHV	6,576	6,912	6,672	6,596

[a] On a per turbine basis.

[b] One-half of the total steam turbine output.

[c] Multiply by 2 to get the output per power block.

Notes:

°F = degrees Fahrenheit
Btu/kWh = British thermal unit(s) per kilowatt-hour
kW = kilowatt
LHV = lower heating value
RH = relative humidity

TABLE 2-2
Simple-Cycle Output Per Turbine

	110°F – 8% RH (Evaporative Cooling On)	32°F – 87% RH (Evaporative Cooling Off)	66°F – 58% RH Evaporative Cooling On)
Gas Turbine Heat Input, MMBtu/hr, HHV	737	880	885
Gas Turbine Gross Output, kW	77,501	100,393	100,814
Net Power Output, kW	76,041	98,934	99,355
Net Plant Heat Rate, Btu/kWh, LHV	8,726	8,012	8,027
Net Plant Heat Rate, Btu/kWh, HHV	9,686	8,894	8,910

There will be no new transmission lines or gas lines needed for the project. Each of the components is discussed in more detail below.

2.1 Combined-Cycle Turbine Data

The combined-cycle power block will consist of two GE Frame 7FA.05 CTGs, each rated at 231.2 MW (ISO gross) and equipped with dry low NO_x combustors, evaporative inlet air cooling, an SCR, and an oxidation catalyst, two HRSGs, and an STG rated at 230.9 MW (ISO gross). Each turbine will be equipped with inlet air filters and coolers. The turbines will combust natural gas exclusively. Total heat input for two turbines at nominal conditions is 4,496 MMBtu/hr, HHV basis, and fuel use at these conditions is approximately 4.28 million cubic feet per hour (MMcf/hr), based on a natural gas heat content of 1,050 British thermal unit(s) per cubic foot (Btu/cf). Pertinent turbine specifications are summarized in Table 2-3.

TABLE 2-3
Combined-Cycle Turbine Data

Parameter	Specification
CT Manufacturer	General Electric
Model	Frame 7FA.05
Fuel Type	Natural gas
Maximum Power Output	236.14 MW (1 turbine @ 32°F, no duct firing)
Maximum Heat Input	2,273 MMBtu/hr, HHV (1 turbine @ 32°F)
Maximum Fuel Consumption	2.16 MMcf/hr, HHV (1 turbine @ 32°F, 1,050 Btu/cf)
Maximum Exhaust Flow	75.7 MMcf/hr, dry @ 15% O_2 (1 turbine @ 32°F)
NOx Combustion Control	DLN 9 ppm
Post Combustion Control	SCR 2.0 ppm, 1-hour average
Ammonia Injection Rate per turbine	242.0 lb/hr maximum
Steam Turbine Output at 63°F Ambient	229.68 MW @ 66°F
Net Plant Heat Rate, LHV	5,967 Btu/kW @ ISO
Net Plant Heat Rate, HHV	6,576 Btu/kW @ ISO

Notes:
Btu/kW = British thermal unit(s) per kilowatt
DLN = dry low NO_x
lb/hr = pound(s) per hour
O_2 = oxygen
ppm = part(s) per million

Each turbine will exhaust to an HRSG. The HRSGs are designed to convert heat from the exhaust gas to produce steam for use in the steam turbine. Exhaust gases enter the HRSG at approximately 1,100 degrees Fahrenheit (°F). The HRSGs and steam turbine both employ a triple pressure design. Feed water into the HRSG will be converted to high, intermediate, and low-pressure steam for use in the steam turbine. The steam exits the steam turbine as low-pressure steam, enters the air-cooled condenser, and is cooled and condensed back into water. Each HRSG will vent to a separate exhaust stack.

2.2 Simple-Cycle Turbine Data

The simple-cycle power block will consist of two GE LMS-100PB CTGs, each rated at 100.8 MW (average ambient temperature gross) and equipped with dry low NO_x combustors, evaporative inlet air-cooling, an SCR, and an oxidation catalyst. The turbines will combust natural gas exclusively. Total heat input for two turbines at nominal conditions is 1,770 MMBtu/hr, HHV basis, and fuel use at these conditions is approximately 1.69 MMcf/hr, based on a natural gas heat content of 1,050 Btu/cf. Pertinent turbine specifications are summarized in Table 2-4.

TABLE 2-4
Simple-Cycle Turbine Data

Parameter	Specification
CT Manufacturer	General Electric
Model	LMS-100PB
Fuel Type	Natural gas
Maximum Power Output	100.4 MW (1 turbine @ 32°F, no duct firing)
Maximum Heat Input	880 MMBtu/hr, HHV (1 turbine @ 32°F)
Maximum Fuel Consumption	0.84 MMcf/hr, HHV (1 turbine @ 32°F, 1,050 Btu/cf)
Maximum Exhaust Flow	56.3 MMcf/hr, dry @ 15% O_2 (1 turbine @ 32°F)
NOx Combustion Control	DLN 25 ppm
Post Combustion Control	SCR 2.5 ppm, 1-hour average
Ammonia Injection Rate per turbine	180 lb/hr maximum
Net Plant Heat Rate, LHV	8,027 Btu/kW @ 66°F
Net Plant Heat Rate, HHV	8,910 Btu/kW @ 66°F

Each turbine will exhaust to an exhaust transition containing the air pollution control system and will vent to a separate exhaust stack.

2.3 Auxiliary Boiler

The combined-cycle power block will use steam supplied from the auxiliary boiler to reach its base load quickly while simultaneously reducing both startup time of the gas turbines and the associated emissions. The auxiliary boiler specifications are listed in Table 2-5.

TABLE 2-5
Auxiliary Boiler Specifications

Parameter	Specification
Boiler Manufacturer	Rentech
Maximum Heat Input	71 MMBtu/hr
Model No.	D-Type
Boiler Type	Water-tube
Fuel Type	Natural Gas
Maximum Fuel Consumption	0.068 MMcf/hr

TABLE 2-5
Auxiliary Boiler Specifications

Parameter	Specification
Maximum Exhaust Flow	29,473 acfm
Maximum Exhaust Temperature	318°F
NO_x Combustion Control	Low NO_x Burner
NO_x BACT Concentration at Stack Outlet	5 ppm @ 3% O_2 (post-SCR)
CO BACT Concentration at Stack Outlet	50 ppm @ 3% O_2 (post-SCR)

Note:
acfm = actual cubic feet per minute

2.4 Air Pollution Control (APC) Equipment

APC equipment will be installed to control NO_x, CO, and volatile organic compounds (VOC) from the gas turbines. Each APC system will consist of the following: 1) dry low NO_x (DLN) burners, 2) SCR, and 3) oxidation catalyst.

DLN Burners - Each CTG will include built-in pollution controls based on a dry combustion design (dry low-NO_x combustor) to reduce NO_x emissions. This control will reduce the combined-cycle CTG NO_x emissions to 9 part(s) per million volume, dry basis (ppmvd) at 15 percent oxygen (O_2) and the simple-cycle CTG NO_x emissions to 25 ppmvd at 15 percent O_2. The dry low NO_x control will be fully operational when the turbine reaches a load of approximately 60 percent or more.

Oxidation Catalyst System – An oxidation catalyst will be installed in the HRSG section of the combined-cycle turbines and the exhaust transition for the simple-cycle turbines. The catalyst will be designed to reduce exhaust gas CO to 2.0 ppmvd or less at 15 percent O_2 and VOC to 2.0 ppmvd at 15 percent O_2. Pertinent oxidation catalyst specifications are provided in Tables 2-6 and A-7.

TABLE 2-6
Combined-Cycle Oxidation Catalyst Data

Parameter	Specification
Manufacturer	BASF
Catalyst Type	Palladium in a honeycomb structure
Catalyst Volume	265.8 cf
Catalyst Area	1,679 ft^2
Reactor Dimensions	2.1"L X 26.17' W X 71.8' H (includes SCR catalyst housing)
Space Velocity	467,260 hr^{-1}
Area Velocity	73,971 ft/hr
CO Removal Efficiency	70 – 85%
Outlet CO	2.0 ppmvd @ 15% O_2
VOC Removal Efficiency	50 – 60%
Outlet VOC	2.0 ppmvd @ 15% O_2
Minimum Operating Temperature	570°F

Notes:
cf = cubic feet
ft^2 = square feet
ft/hr = feet per hour
H = height
hr^{-1} = per hour
L = length
W = width

TABLE 2-7
Simple-Cycle Oxidation Catalyst Data

Parameter	Specification
Manufacturer	BASF Camet
Catalyst Type	Palladium in a honeycomb structure
Catalyst Volume	165.6 cf
Catalyst Area	794.8 ft^2
Reactor Dimensions	0.21' L X 22' W X 36' H (includes SCR catalyst housing)
Space Velocity	139,539 hr^{-1}
Area Velocity	29,071 ft/hr
CO Removal Efficiency	90 – 96%
Outlet CO	4.0 ppmvd @ 15% O_2
VOC Removal Efficiency	50 – 60%
Outlet VOC	2.0 ppmvd at 15% O_2
Minimum Operating Temperature	500°F

Selective Catalytic Reduction System – An SCR catalyst will be installed in the HRSG section of the combined-cycle turbines, the exhaust transition for the simple-cycle turbines, and the auxiliary boiler. The SCR system is expected to reduce NO_x emissions to 2.0 ppmvd at 15 percent O_2 on a 1-hour average for the combined-cycle turbines, 2.5 ppmvd at 15 percent O_2 for the simple-cycle turbines, and 5 ppmvd at 3 percent O_2 for the auxiliary boiler. The SCR catalyst will be located downstream of the CO catalyst, and will consist of a vanadium/titanium/tungsten type catalyst in a honeycomb structure. Aqueous ammonia (ammonium hydroxide at 19 percent concentration by weight) from the storage tank will be vaporized, diluted with air, and injected into the exhaust through an injection grid. The amount of ammonia injected will vary depending on NO_x reduction requirements, but will be approximately a 1:1 molar ratio of ammonia to NO_x. Tables 2-8 and 2-9 present the combined- and simple-cycle SCR data.

TABLE 2-8
Combined-Cycle SCR Catalyst Data

Parameter	Specification
Manufacturer	Cormetech
Catalyst Type	Titanium/Vanadium/Tungsten honeycomb
Catalyst Volume	1,289 cf
Catalyst Area	1,841 ft^2
Reactor Dimensions	18" L X 25.71' W X 71.6' H
Space Velocity	96,352 hr^{-1}
Area Velocity	67,462 ft/hr
Ammonia Injection Rate	242 lbm/hr
Ammonia Slip	5.0 ppm
Outlet NO_x	2.0 ppm @ 15% O^2
Guarantee	25,000 hours of operation, or 5 years
SCR/CO Catalyst Total Cost	$1 million
Operating Temperature Range	570°F – 692°F

Note:
lbm/hr – pound-mole per hour

TABLE 2-9
Simple-Cycle SCR Catalyst Data

Parameter	Specification
Manufacturer	Cormetech CMHT
Catalyst Type	Titanium/Vanadium/Tungsten honeycomb
Catalyst Volume	1,370.4 cf
Catalyst Area	126.5 ft^2
Reactor Dimensions	11.5' L X 10.83' W X 11' H (includes CO catalyst housing)
Space Velocity	16,859 hr^{-1}
Area Velocity	182,639 ft/hr
Ammonia Injection Rate	180 lbm/hr
Ammonia Slip	5.0 ppm
Outlet NO_x	2.5 ppm @ 15% O_2
Guarantee	24,000 hours of operation, or 3 years
SCR/CO Catalyst Total Cost	$1.1 million
Operating Temperature Range	500°F – 870°F

The SCR catalyst for the auxiliary boiler will be installed downstream of the low NO_x burner and will reduce the exhaust NO_x emissions from 9 ppmvd to 5 ppmvd at 3 percent O_2. The SCR catalyst will be manufactured by B&W. The catalyst material will be vanadium based on a homogeneous honeycomb titanium support matrix. The catalyst model will be from the FM Series. The total catalyst volume is 46 cubic feet (cf). The catalyst dimensions will be 3 feet 8 inches high by 5 feet 5 inches wide by 7 feet 3 inches in length. The life cycle of the SCR modules is expected to be 3 years. The SCR warranty is 5 ppmvd ammonia slip at 3 percent O_2. The operating range for the SCR catalyst will be 415°F to 628°F. Table 2-10 is a summary of the specifications of the SCR catalyst for the auxiliary boiler.

TABLE 2-10
Auxiliary Boiler SCR Catalyst Summary

Parameters	Specifications
Catalyst Manufacturer	B&W
Catalyst Description	Vanadium
Catalyst Model No.	FM Series
Catalyst Volume	46 cf
Catalyst Area	28 ft^2
Space Velocity	485 hr^{-1}
Area Velocity	47,800 ft/hr
Stack Outlet CO	50 ppmvd @ 3% O_2
Stack Outlet NO_x	5 ppmvd @ 3% O_2 (1-hour average)
Catalyst Life	3 years
Ammonia Injection Rate	19% aqueous ammonia, provided by the Combined-cycle Power Block Aqueous Ammonia

TABLE 2-10
Auxiliary Boiler SCR Catalyst Summary

Parameters	Specifications
Ammonia Source	Storage Tanks
Maximum Operating Temperature	628°F

2.5 Exhaust Stacks

Each combined-cycle turbine/HRSG will be equipped with an identical 20-foot-diameter, 150-foot-tall stack. Each simple-cycle turbine will be equipped with an identical 13.5-foot-diameter, 80-foot-tall stack. The stacks will contain sampling ports for exhaust gas testing. Table 2-11 contains stack data.

TABLE 2-11
Stack Data

Specification	Combined-Cycle	Simple-Cycle	Auxiliary Boiler
Stack Diameter (ft)	20	13.5	3
Stack Height (ft)	150	80	80
Stack Area (ft^2)	314.2	143.1	7.07
Exhaust Gas Temperature (°F)	194	853	318
Exhaust Gas Volume (MMcf/hr)	75.72 @ 32°F	56.29 @ 32°F	1.77
Exhaust Gas Velocity (ft/min)	4,017 @ 32°F	6,551 @ 32°F	4,170

Notes:
ft = foot
ft/min = feet per minute

2.6 Monitoring Systems

Each turbine will be equipped with continuous stack monitors for NO_x, CO, and O_2, along with a fuel meter. The auxiliary boiler will be equipped with a NO_x, O_2, and fuel meter. A data acquisition system is required to collect information from the analyzers and fuel meters to calculate exhaust flows and mass emissions of NO_x for transmission through the remote terminal unit (RTU). Other parameters which are required to be measured and recorded include the ammonia injection rate, exhaust temperature prior to the SCR catalyst, CTG output, and pressure drop across the SCR catalyst. A NO_x analyzer will be placed upstream of the SCR catalyst for fine tuning the ammonia injection rate and also for use in estimating ammonia slip.

2.7 Ammonia Storage Tanks

Each power block will include a separate ammonia storage tank. The combined-cycle power block and auxiliary boiler will use a 40,000-gallon tank (13 feet in diameter and 45 feet long horizontal tank) and the simple-cycle power block will use a 15,000-gallon tank (6 feet in diameter and 18 feet long horizontal tank) to store a 19 percent aqueous ammonia solution for use in the turbines and auxiliary boiler SCRs. These tanks are horizontal pressure vessels with pressure relief valves (PRVs) set at 50 pressure square inch, gauge (psig). During loading, vapors from the tanks are vented back to the filling truck through the vapor return line. The tanks are designed so that under normal operating conditions, the pressure will not exceed the PRV setting. Expected average combined-cycle and simple-cycle turbine ammonia use is about 32.3 and 24 gallons per hour (242 pound(s) per hour [lb/hr] for the combined-cycle and 180 lb/hr for the simple-cycle) per CTG.

2.8 Cooling System

There are no cooling towers associated with the combined-cycle turbines as they will be air-cooled. Exhaust steam from the STG will be condensed in an air-cooled condenser. The air-cooled condenser will utilize large fans to blow ambient air across finned tubes through which the low-pressure steam flows. The condensate collects in a receiver located under the air-cooled condenser; condensate pumps will then return the condensate from the receiver back to the HRSGs for reuse. Steam generated by the auxiliary boiler will pass through the HRSGs and STG, and will be condensed in the air-cooled condenser. The simple-cycle turbines generate no steam; therefore, steam condensing is not required.

2.9 Oil Water Separator

There will be two new oil water separators (OWS) installed to serve the each power block. These OWS will collect potentially oily wastewater from equipment area wash downs and lubricant containing areas. The only potential oil contaminant is lubricating oil associated with the gas turbines and associated feed water pumps. Oil will be collected in the OWS and will be removed by vacuum truck before the oil collection section reaches its capacity.

SECTION 3
Emissions

Emissions from the gas turbines and auxiliary boiler will consist of NO_x, CO, carbon dioxide equivalent (CO_2e), VOC, PM_{10}, $PM_{2.5}$, and SO_x, plus toxics. Emissions are calculated for four basic operational modes, as follows:

1. Commissioning – a one-time event which occurs following installation and just prior to bringing the turbine online for commercial operation
2. Startup – occurs each time the turbine is started
3. Normal operation
4. Shutdown – occurs each time the turbine is shut down

3.1 Operating Schedule

AES has proposed the operating schedule for HBEP shown in Table 3-1 on a per turbine basis. The emissions and modeling analysis assume simultaneous startup of all combustion units is possible.

TABLE 3-1
Operating Schedule

	GE Frame 7FA.05		GE LMS-100PB	
Parameter	Events	Hours	Events	Hours
Annual Hours	--	6,100	--	1,150
Annual Cold Startup	24	24.0	0	--
Annual Warm Startup	100	50.0	0	--
Annual Hot Startup	376	188	350	175
Annual Shutdown	500	250	350	76
Total Annual Startup/ Shutdown Hours	--	512	--	251
Total Annual Operating Hours (per turbine)	--	6,612	--	1,401
Monthly Cold Startup	2	2.0	0	--
Monthly Warm Startup	15	7.50	0	--
Monthly Hot Startup	45	22.5	62	31.0
Monthly Shutdown	62	31.0	62	13.4
Total Monthly Startup/ Shutdown Hours (per turbine)	--	63.0	--	44.4
Monthly Operating Hours (per turbine)	--	681	--	700

The auxiliary boiler may operate 8,760 hours per year, with 24 cold starts, 48 warm starts, and 48 hot starts. Monthly operation assumes 2 cold starts, 4 warm starts, and 4 hot starts.

The maximum hourly emissions for normal operation, startups, and shutdowns are presented in Tables 3-2 through 3-5 for each combustion technology.

TABLE 3-2

Maximum Hourly Emissions Normal Operation (1 Turbine)

Pollutant	Uncontrolled GE FA.05 Hourly Emissions[a]	Uncontrolled GE LMS-100PB Hourly Emissions[b]	Controlled GE FA.05 Hourly Emissions	Controlled GE LMS-100PB Hourly Emissions
NO_x	59.3	82.9	16.5	8.29
CO	35.2	201.8	10.0	8.07
VOC	1.58	4.6	1.58	2.31
PM_{10}	9.0	6.2	9.0	6.2
SO_x	4.86	1.6	4.86	1.6
Ammonia	/////////	/////////	15.3	6.1

[a] Uncontrolled emission rates based on DLN without SCR, NO_x = 9 ppm and CO = 7.07 ppm.

[b] Uncontrolled emission rates based on DLN without SCR, NO_x = 25 ppm, CO = 100 ppm, and VOC = 4 ppm.

TABLE 3-3

Maximum Hourly And Total Emissions Startups and Shutdowns (1 GE Frame 7FA.05 Turbine)

	Cold Start, 60 minutes		Warm Start, 30 minutes		Hot Start, 30 minutes		Shutdown, 30 minutes	
Pollutant	lb/hr[b]	lb/event	lb/hr[b]	lb/event	lb/hr[b]	lb/event	lb/hr[b]	lb/event
NO_x[a]	61.0	61.0	25.2	17	25.2	17	18.2	10
CO[a]	325	325	142	137	142	137	138	133
VOC[a]	36	36	25.8	25	25.8	25	32.8	32
PM_{10}	9.0	9.0	9.0	4.5	9.0	4.5	9.0	4.5
SO_x	4.86	4.86	4.86	2.4	4.86	2.4	4.86	2.4

[a] The NO_x, CO, and VOC emissions in this table are as reported by AES.

[b] The lb/hr numbers represent the highest hour during the event.

Note:

lb/event = pound(s) per event

TABLE 3-4

Maximum Hourly and Total Emissions Startups and Shutdowns (1 GE LMS-100PB Turbine)

	Start, 30 minutes		Shutdown, 13 minutes	
Pollutant	lb/hr[b]	lb/event	lb/hr[b]	lb/event
NO_x[a]	20.7	16.6	9.6	3.1
CO[a]	19.4	15.4	34.4	28.1
VOC[a]	4.0	2.8	4.9	3.1
PM_{10}	6.2	3.12	6.2	3.12
SO_x	1.6	0.82	1.6	0.82

[a] The NO_x, CO, and VOC emissions in this table are as reported by AES.

[b] The lb/hr numbers represent the highest hour during the event.

TABLE 3-5
Maximum Hourly And Total Emissions Startups and Shutdowns (Auxiliary Boiler)

Pollutant	Cold Start, 170 minutes		Warm Start, 85 minutes		Hot Start, 25 minutes	
	lb/hr[b]	lb/event	lb/hr[b]	lb/event	lb/hr[2]	lb/event
NO_x[a]	1.48	4.2	1.48	2.1	0.87	0.62
CO[a]	1.52	4.3	1.55	2.2	2.29	0.64
VOC[a]	1.66	4.69	1.62	2.3	0.85	0.69
PM_{10}	0.30	0.85	0.30	0.425	0.30	0.125
SO_x	0.05	0.136	0.05	0.068	0.05	0.02

[a] The NO_x, CO, and VOC emissions in this table are as reported by AES.

[b] The lb/hr numbers represent the highest hour during the event.

The monthly operating schedule, along with the maximum monthly and average daily emissions, are presented in Tables 3-6, 3-7, and 3-8 for the combined-cycle and simple-cycle turbines.

TABLE 3-6
Monthly Operating Schedule (GE FA.05 Turbine)

Parameter	Number	Hours
Cold Starts/Month	2	2.0
Warm Starts/Month	15	7.50
Hot Starts/Month	45	22.5
Shutdowns/Month	62	31.0
Total Start-Stop/Month	NA	63.0
Total Monthly Turbine Operating Hours (not including starts and stops)	NA	681

Note:

NA = Not applicable

TABLE 3-7
Monthly Operating Schedule (GE LMS-100PB Turbine)

Parameter	Number	Hours
Starts/Month	62	31.0
Shutdowns/Month	62	13.4
Total Start-Stop/Month	NA	44.4
Total Monthly Turbine Operating Hours (not including starts and stops)	NA	700

Note:

NA = Not applicable

As shown in Table 3-8, daily emissions are based on monthly emissions divided by 30, based on the monthly operating schedule in Table 3-6.

TABLE 3-8
Maximum Monthly and Average Daily Emissions (GE FA.05 Turbine)

Pollutant	lb/month	Average lb/day
NO_X	25,587	853
CO	43,895	1,463
VOC	8,847	295
SO_2	2,385	79.5
PM_{10}	13,392	446
$PM_{2.5}$	13,392	446

Notes:

lb/day = pound(s) per day

lb/month = pound(s) per month

As shown in Table 3-9, daily emissions are based on monthly emissions divided by 30, based on the monthly operating schedule in Table 3-7.

TABLE 3-9
Maximum Monthly and Average Daily Emissions (GE LMS-100PB Turbine)

Pollutant	lbs/month	Average lbs/day
NO_X	14,039	468
CO	16,689	556
VOC	3,961	132
SO_2	812	27.1
PM_{10}	9,288	310
$PM_{2.5}$	9,288	310

Table 3-10 summarizes the auxiliary boiler maximum hourly, daily, and annual emissions estimates.

TABLE 3-10
Auxiliary Boiler Maximum Hourly, Daily, and Annual Emissions Estimates

Aux boiler	NO_X	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$	Fuel Use (MMBtu)
Hourly Emissions (lb/hr)	0.42	2.83	0.28	0.048	0.30	0.30	70.8
Daily Emissions (lb/day)	5.80	35.0	4.16	0.60	3.77	3.77	878
Monthly Emissions (lb/month)	174	1,051	125	17.9	113	113	26,327
Annual Emissions (lb/year)	2,054	12,384	1,473	211	1,333	1,333	310,096
Annual Emissions (tpy)	1.03	6.19	0.74	0.11	0.67	0.67	--

Notes:

1. Hourly emissions are based on the maximum hourly firing rate.
2. Daily emissions are the monthly emissions averaged over 30 days.
3. Monthly and annual emissions assume two cold starts, four warm starts, and four hot starts per month, and operation at the maximum hourly firing rate.

3.2 Annual Emissions

Table 3-11 summarizes the annual criteria pollutants for each combustion technology.

TABLE 3-11
Annual Criteria Pollutant Emissions

	Annual Emissions per Unit (tpy)			Annual Emissions per Combustion Technology (tpy)*		
Pollutant	**GE 7FA.05**	**GE LMS-100PB**	**Auxiliary Boiler**	**GE 7FA.05**	**GE LMS-100PB**	**Auxiliary Boiler**
NO_X	56.7	8.2	1.03	113	16.4	1.03
CO	92.2	12.3	6.19	184	24.5	6.19
VOC	18.3	2.35	0.74	36.7	4.7	0.74
SO_2	5.30	0.38	0.11	10.6	0.76	0.11
PM_{10}	29.8	4.37	0.67	59.6	8.74	0.67
$PM_{2.5}$	29.8	4.37	0.67	59.6	8.74	0.67

*Accounts for 2 GE 7FA.05 combined-cycle turbines, 2 GE LMS-100PB simple-cycle turbines, and one auxiliary boiler.

Table 3-12 summarizes the annual toxic emissions for the combined-cycle combustion turbines.

TABLE 3-12
Combined-cycle: Summary of Operation Emissions – Air Toxics

Proposed Project	Emission Factors		Emissions (per Turbine)		
Compound	**lb/MMcf [a]**	**lb/MMBtu [a]**	**lbs/hr**	**lbs/yr**	**tpy**
Ammonia [b]	5 ppm	-	15.2	100,290	50.1
Acetaldehyde	4.08E-02	4.00E-05	0.091	595	0.30
Acrolein	6.53E-03	6.40E-06	0.015	95	0.048
Benzene	1.22E-02	1.20E-05	0.027	178	0.089
1,3-Butadiene	4.39E-04	4.30E-07	0.0010	6.39	0.0032
Ethylbenzene	3.26E-02	3.20E-05	0.073	476	0.24
Formaldehyde [c]	3.67E-01	3.60E-04	0.82	5,351	2.68
Hexane	NA	NA	NA	NA	NA
Naphthalene	1.33E-03	1.30E-06	0.0030	19.3	0.010
PAHs [d]	2.24E-03	2.20E-06	0.0025	16.4	0.008
Propylene (Propene)	NA	NA	NA	NA	NA
Propylene Oxide	2.96E-02	2.90E-05	0.066	431	0.22
Toluene	1.33E-01	1.30E-04	0.30	1,932	0.97
Xylene	6.53E-02	6.40E-05	0.15	951	0.48
TOTAL HAPs				**10,052**	**5.03**
TOTAL TACs				**5,536**	**2.77**

TABLE 3-12

Combined-cycle: Summary of Operation Emissions – Air Toxics

Proposed Project	Emission Factors		Emissions (per Turbine)		
Compound	lb/MMcf [a]	lb/MMBtu [a]	lbs/hr	lbs/yr	tpy

[a] Obtained from Table 3.1-3 of *AP-42* (EPA, 2000), with the exception of formaldehyde and ammonia. Units of lbs/MMcf calculated by multiplying lbs/MMBtu by the gas heat content.

[b] Based on the operating exhaust NH_3 limit of 5 ppmv @ 15% O_2 and an F-factor of 8,710.

[c] Emission factor was modified to reflect the SCAQMD's formaldehyde emission factor of 3.6×10^{-4}.

[d] Per Section 3.1.4.3 of *AP-42* (EPA, 2000), PAH emissions were assumed to be controlled up to 50% through the use of an oxidation catalyst.

Notes:

NA = Not applicable

Hourly per turbine emissions calculated by multiplying the emission factor by 2273 MMBtu/hr- HHV.

Annual per turbine emissions calculated by multiplying the emission factor by 2248 MMBtu/hr- HHV and 6612 hours/year.

Table 3-13 summarizes the annual toxic emissions for the simple-cycle combustion turbines.

TABLE 3-13
Simple-cycle: Summary of Operation Emissions – Air Toxics

Proposed Project	Emission Factors		Emissions (per Turbine)			Emissions (Facility Total)		
Compound	**lb/MMcf [a]**	**lb/MMBtu [a]**	**lbs/hr**	**lbs/yr**	**tpy**	**lbs/hr**	**lbs/yr**	**tpy**
Ammonia [b]	5 ppm	-	6.14	8,595	4.3	12.3	17,190	8.6
Acetaldehyde	4.08E-02	4.00E-05	0.035	50	0.025	0.071	99	0.05
Acrolein	6.53E-03	6.40E-06	0.0057	7.9	0.004	0.011	15.9	0.008
Benzene	1.22E-02	1.20E-05	0.011	14.9	0.007	0.021	29.8	0.015
1,3-Butadiene	4.39E-04	4.30E-07	0.00038	0.53	0.00027	0.00076	1.07	0.0005
Ethylbenzene	3.26E-02	3.20E-05	0.028	40	0.020	0.057	79	0.04
Formaldehyde [c]	3.67E-01	3.60E-04	0.32	446	0.22	0.64	893	0.45
Hexane	NA	NA	NA	NA	NA	NA	NA	NA
Naphthalene	1.33E-03	1.30E-06	0.0012	1.61	0.0008	0.0023	3.2	0.0016
PAHs [d]	2.24E-03	2.20E-06	0.0010	1.36	0.0007	0.0019	2.7	0.0014
Propylene (Propene)	NA	NA	NA	NA	NA	NA	NA	NA
Propylene Oxide	2.96E-02	2.90E-05	0.026	36	0.018	0.051	72	0.04
Toluene	1.33E-01	1.30E-04	0.12	161	0.08	0.23	322	0.16
Xylene	6.53E-02	6.40E-05	0.057	79	0.04	0.11	159	0.08
TOTAL HAPs				839	0.42		1,677	0.84
TOTAL TACs				462	0.23		924	0.46

[a] Obtained from Table 3.1-3 of AP-42 (EPA, 2000), with the exception of formaldehyde and ammonia. Units of lb/MMscf calculated by multiplying lb/MMBtu by the gas heat content.

[b] Based on the operating exhaust NH_3 limit of 5 ppmv @ 15% O_2 and an F-factor of 8,710.

[c] Emission factor was modified to reflect the SCAQMD's formaldehyde emission factor of $3.6x10^{-4}$.

[d] Per Section 3.1.4.3 of *AP-42* (EPA, 2000), PAH emissions were assumed to be controlled up to 50% through the use of an oxidation catalyst.

Notes:

NA = Not applicable

Hourly per turbine emissions calculated by multiplying the emission factor by 885 MMBtu/hr- HHV.

Annual per turbine emissions calculated by multiplying the emission factor by 885 MMBtu/hr- HHV and 1401 hours/year.

Table 3-14 summarizes the annual toxic emissions for the auxiliary boiler.

TABLE 3-14
Auxiliary Boiler: Summary of Operation Emissions – Air Toxics

Proposed Project	Emission Factors		Emissions		
Compound	lb/MMscf [a]	lb/MMBtu [a]	lbs/hr	lbs/yr [b]	tpy
2-Methylnaphthalene	2.40E-05	2.35E-08	1.67E-06	7.30E-03	3.65E-06
3-Methylchloranthrene	1.80E-06	1.76E-09	1.25E-07	5.47E-04	2.74E-07
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.57E-08	1.11E-06	4.86E-03	2.43E-06
Acenaphthene	1.80E-06	1.76E-09	1.25E-07	5.47E-04	2.74E-07
Acenaphthylene	1.80E-06	1.76E-09	1.25E-07	5.47E-04	2.74E-07
Anthracene	2.40E-06	2.35E-09	1.67E-07	7.30E-04	3.65E-07
Benz(a)anthracene	1.80E-06	1.76E-09	1.25E-07	5.47E-04	2.74E-07
Benzene	2.10E-03	2.06E-06	1.46E-04	6.38E-01	3.19E-04
Benzo(a)pyrene	1.20E-06	1.18E-09	8.33E-08	3.65E-04	1.82E-07
Benzo(b)fluoranthene	1.80E-06	1.76E-09	1.25E-07	5.47E-04	2.74E-07
Benzo(g,h,i)perylene	1.20E-06	1.18E-09	8.33E-08	3.65E-04	1.82E-07
Benzo(k)fluoranthene	1.80E-06	1.76E-09	1.25E-07	5.47E-04	2.74E-07
Butane	2.10E+00	2.06E-03	1.46E-01	6.38E+02	3.19E-01
Chrysene	1.80E-06	1.76E-09	1.25E-07	5.47E-04	2.74E-07
Dibenzo(a,h)anthracene	1.20E-06	1.18E-09	8.33E-08	3.65E-04	1.82E-07
Dichlorobenzene	1.20E-03	1.18E-06	8.33E-05	3.65E-01	1.82E-04
Ethane	3.10E+00	3.04E-03	2.15E-01	9.42E+02	4.71E-01
Fluoranthene	3.00E-06	2.94E-09	2.08E-07	9.12E-04	4.56E-07
Fluorene	2.80E-06	2.75E-09	1.94E-07	8.51E-04	4.26E-07
Formaldehyde	7.50E-02	7.35E-05	5.21E-03	2.28E+01	1.14E-02
Hexane	1.80E+00	1.76E-03	1.25E-01	5.47E+02	2.74E-01
Indeno(1,2,3-cd)pyrene	1.80E-06	1.76E-09	1.25E-07	5.47E-04	2.74E-07
Naphthalene	6.10E-04	5.98E-07	4.23E-05	1.85E-01	9.27E-05
Pentane	2.60E+00	2.55E-03	1.80E-01	7.90E+02	3.95E-01
Phenanathrene	1.70E-05	1.67E-08	1.18E-06	5.17E-03	2.58E-06
Propane	1.60E+00	1.57E-03	1.11E-01	4.86E+02	2.43E-01
Pyrene	5.00E-06	4.90E-09	3.47E-07	1.52E-03	7.60E-07
Toluene	3.40E-03	3.33E-06	2.36E-04	1.03E+00	5.17E-04
Arsenic	2.00E-04	1.96E-07	1.39E-05	6.08E-02	3.04E-05
Barium	4.40E-03	4.31E-06	3.05E-04	1.34E+00	6.69E-04
Beryllium	1.20E-05	1.18E-08	8.33E-07	3.65E-03	1.82E-06
Cadmium	1.10E-03	1.08E-06	7.64E-05	3.34E-01	1.67E-04
Chromium	1.40E-03	1.37E-06	9.72E-05	4.26E-01	2.13E-04
Cobalt	8.40E-05	8.24E-08	5.83E-06	2.55E-02	1.28E-05
Copper	8.50E-04	8.33E-07	5.90E-05	2.58E-01	1.29E-04
Manganese	3.80E-04	3.73E-07	2.64E-05	1.16E-01	5.78E-05

TABLE 3-14
Auxiliary Boiler: Summary of Operation Emissions – Air Toxics

Proposed Project	Emission Factors		Emissions		
Compound	**lb/MMscf** [a]	**lb/MMBtu** [a]	**lbs/hr**	**lbs/yr** [b]	**tpy**
Mercury	2.60E-04	2.55E-07	1.80E-05	7.90E-02	3.95E-05
Molybdenum	1.10E-03	1.08E-06	7.64E-05	3.34E-01	1.67E-04
Nickel	2.10E-03	2.06E-06	1.46E-04	6.38E-01	3.19E-04
Selenium	2.40E-05	2.35E-08	1.67E-06	7.30E-03	3.65E-06
Vanadium	2.30E-03	2.25E-06	1.60E-04	6.99E-01	3.50E-04
Zinc	2.90E-02	2.84E-05	2.01E-03	8.82E+00	4.41E-03
TOTAL HAPs				1,212	0.61
TOTAL TACs				575	0.29

[a] Obtained from Tables 1.4-3 and 1.4-4 of *AP-42* (EPA, 1998). Units of lbs/MMBtu calculated by dividing lbs/MMscf by the gas heat content.

[b] The auxiliary boiler will operate at the maximum hourly firing rate and will have two cold starts, four warm starts, and four hot starts per month.

Notes:

Hourly emissions calculated by multiplying the emission factor by 71 MMBtu/hr- HHV.

Annual per turbine emissions calculated by multiplying the emission factor by 310,096 MMBtu/year- HHV.

SECTION 4

Air Quality Impacts Analysis

An air quality impacts analysis was conducted to compare worst-case ground-level impacts resulting from the Huntington Beach Energy Project (HBEP) with established state and federal ambient air quality standards and applicable South Coast Air Quality Management District (SCAQMD) significance criteria. The stack parameters, emission rates, and results for each modeled scenario are described below, as related to commissioning and operation of the combined-cycle turbines, simple-cycle turbines, and auxiliary boiler.

4.1 Commissioning Impacts Analysis

For commissioning, a total of 6 scenarios were modeled, as listed below:

- Two General Electric (GE) 7FA.05s at 10 percent load with auxiliary boiler operation
- Two GE 7FA.05s at 40 percent load with auxiliary boiler operation
- Two GE 7FA.05s at 80 percent load with auxiliary boiler operation
- Two GE LMS-100PBs at 5 percent load with operation of two GE 7FA.05s and the auxiliary boiler
- Two GE LMS-100PBs at 75 percent load with operation of two GE 7FA.05s and the auxiliary boiler
- Two GE LMS-100PBs at 100 percent load with operation of two GE 7FA.05s and the auxiliary boiler

The stack parameters for each unit included in the modeled scenarios are presented in Appendix A, Table 1. Stack parameters presented include source coordinates, elevation, stack height, temperature, exit velocity, and stack diameter.

The short-term and annual emission rates (in gram(s) per second [g/s] and pound(s) per hour [lb/hr]) for each unit included in the modeled scenarios are presented in Appendix A, Table 2. These emission rates are the highest unabated emissions expected during commissioning. Only nitrogen dioxide (NO_2) and carbon monoxide (CO) were modeled for the short-term averaging periods because sulfur dioxide (SO_2) and particulate matter with aerodynamic diameter less than or equal to 10 microns or 2.5 microns (PM_{10} and $PM_{2.5}$, respectively) are not emitted in amounts greater than normal operating rates. In other words, results for short-term SO_2, PM_{10}, and $PM_{2.5}$ were extracted from the operational modeling results, as discussed later within this response. Additionally, short-term modeling was only included for short-term NO_2 and CO for scenarios where the emission rates were not captured by another commissioning or operation scenario modeled. NO_2, PM_{10}, and $PM_{2.5}$ were modeled for annual averaging periods, and the emission rates account for operation following commissioning activities.

The building parameters included in the modeled scenarios are presented in Appendix A, Table 3. The building parameters for the three GE 7FA.05 commissioning scenarios include the presence of existing Huntington Beach Generating Station (HBGS) Units 1, 2, 3, and 4 in addition to those of the GE 7FA.05s. The building parameters for the three GE LMS-100PB commissioning scenarios include the presence of the two GE 7FA.05s and existing HGBS Units 1 and 2 in addition to those of the GE LMS-100PBs.

The results for each modeled scenario are presented in Appendix A, Table 4. As with the emission rates, these results are sorted by short-term and annual averaging periods. As noted, impacts for the first scenario are only for a single GE 7FA.05 turbine, with NO_2 modeled using the plume volume molar ratio method (PVMRM). Impacts for the GE LMS-100PB scenarios include operation of the auxiliary boiler and GE 7FA.05s at the worst-case operating conditions, as discussed later within this response. These results were used to identify the maximum impacts provided below.

Table 4-1 presents the results of the GE 7FA.05 commissioning impacts analysis. As indicated, the maximum predicted CO, NO_2, SO_2, annual PM_{10}, and $PM_{2.5}$ commissioning impacts combined with the background concentrations will be below the ambient air quality standards for each averaging period. For PM_{10}, the 24-hour background concentration exceeds the California Ambient Air Quality Standard (CAAQS) without adding the modeled concentration. As a result, the predicted impact combined with the background concentration would be greater than the CAAQS. However, the commissioning activity would be finite, and the Project Owner will limit the hours of operation required to complete commissioning activities. Additionally, as described in Section 5.1.7.3 of the permit application, HBEP emissions will be fully offset consistent with SCAQMD Rule 1303 through the SCAQMD internal offset bank under SCAQMD Rule 1304(a)(2). Therefore, impacts from GE 7FA.05 commissioning will be less than significant.

TABLE 4-1
GE 7FA.05 Commissioning Impacts Analysis – Maximum Modeled Impacts Compared to the Ambient Air Quality Standards

Pollutant	Averaging Time	Maximum Modeled Concentration, $\mu g/m^3$ [a]	Background Concentration, $\mu g/m^3$ [b]	Total Predicted Concentration, $\mu g/m^3$	CAAQS, $\mu g/m^3$	NAAQS, $\mu g/m^3$
CO	1-hour	3,377	3,321	6,698	23,000	40,000
	8-hour	1,793	2,519	4,312	10,000	10,000
NO_2	1-hour (max)[c]	179	142	321	339	—
	Annual[d]	0.66	21.8	22.5	57	100
SO_2	1-hour (max)	5.79	20.2	26.0	655	—
	3-hour	4.99	20.2	25.2	—	1,300
	24-hour	1.70	5.20	6.90	105	—
PM_{10}	24-hour	5.69	51.0	56.7	50	150
	Annual	0.59	19.3	19.9	20	—
$PM_{2.5}$	24-hour (98th percentile)[e]	3.31	21.3	24.6	—	35
	Annual	0.59	8.60	9.19	12	12

[a] Maximum modeled 1-hour NO_2 and 1- and 8-hour CO concentrations are for commissioning of a single GE 7FA.05 turbine only. Maximum modeled annual NO_2; 1-, 3-, and 24-hour SO_2; and 24-hour and annual $PM_{10/2.5}$ concentrations include impacts from both GE 7FA.05 turbines and the auxiliary boiler.
[b] Background concentrations were the highest concentrations monitored during 2011 through 2013.
[c] The maximum 1-hour NO_2 concentration is based on American Meteorological Society/U.S. Environmental Protection Agency (EPA) Regulatory Model (AERMOD) PVMRM output with an in-stack NO_2 to oxides of nitrogen (NO_X) ratio of 0.5 and an out-of-stack NO_2 to NO_X ratio of 0.9 (EPA, 2011; California Air Pollution Control Officer's Association [CAPCOA], 2011). Hourly paired ozone data is from the SCAQMD Costa Mesa monitoring station.
[d] The maximum annual NO_2 concentration includes an ambient NO_2 ratio of 0.75 (EPA, 2005).
[e] The total predicted concentration for the federal 24-hour $PM_{2.5}$ standard is the 5-year average, high-8th-high modeled concentration combined with the 3-year average, 98th percentile background concentration.

Table 4-2 presents the results of the GE LMS-100PB commissioning impacts analysis. As indicated, the maximum predicted CO, NO_2, SO_2, annual PM_{10}, and $PM_{2.5}$ commissioning impacts combined with the background concentrations will be below the ambient air quality standards for each averaging period. For PM_{10}, the 24-hour background concentration exceeds the CAAQS without adding the modeled concentration. As a result, the predicted impact combined with the background concentration would be greater than the CAAQS. However, the commissioning activity would be finite, and the Project Owner will limit the hours of operation required to complete commissioning activities. Additionally, as described in Section 5.1.7.3 of the PTA, HBEP emissions will be fully offset consistent with SCAQMD Rule 1303 through the SCAQMD internal offset bank under SCAQMD Rule 1304(a)(2). Therefore, impacts from GE LMS-100PB commissioning will be less than significant.

TABLE 4-2
GE LMS-100PB Commissioning Impacts Analysis – Maximum Modeled Impacts Compared to the Ambient Air Quality Standards

Pollutant	Averaging Time	Maximum Modeled Concentration, µg/m³	Background Concentration, µg/m³ [a]	Total Predicted Concentration, µg/m³	CAAQS, µg/m³	NAAQS, µg/m³
CO	1-hour	527	3,321	3,848	23,000	40,000
	8-hour	125	2,519	2,644	10,000	10,000
NO_2 [b]	1-hour (max)	79.1	142	221	339	—
	Annual	0.49	21.8	22.3	57	100
SO_2	1-hour (max)	5.69	20.2	25.9	655	—
	3-hour	4.94	20.2	25.1	—	1,300
	24-hour	1.66	5.20	6.86	105	—
PM_{10}	24-hour	5.38	51.0	56.4	50	150
	Annual	0.53	19.3	19.8	20	—
$PM_{2.5}$	24-hour (98th percentile) [c]	3.13	21.3	24.4	—	35
	Annual	0.53	8.60	9.13	12	12

[a] Background concentrations were the highest concentrations monitored during 2011 through 2013.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 (EPA, 2011) and 0.75 (EPA, 2005), respectively.
[c] The total predicted concentration for the federal 24-hour $PM_{2.5}$ standard is the 5-year average, high-8th-high modeled concentration combined with the 3-year average, 98th percentile background concentration.

There are no commissioning activities associated with installation of the auxiliary boiler. Therefore, it was included in each of the modeled commissioning scenarios as being in normal operation only.

4.2 Operation Impacts Analysis

To evaluate the worst-case air quality impacts, each technology was assessed at peak, average, and minimum load at low, average, and high ambient temperatures. This assessment, referred to as a load analysis, included a total of 41 modeled scenarios, as listed below:

- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 32 degrees Fahrenheit (°F)
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 32°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 32°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 32°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 32°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 32°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 32°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 32°F

- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 32°F
- Operation of two GE 7FA.05s at maximum load with evaporative cooling, two GE LMS-100PBs at maximum load with evaporative cooling, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at maximum load with evaporative cooling, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at maximum load with evaporative cooling, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at maximum load with evaporative cooling, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at maximum load with evaporative cooling, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at maximum load with evaporative cooling, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at maximum load with evaporative cooling, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 65.8°F
- Operation of two GE 7FA.05s at maximum load with evaporative cooling, two GE LMS-100PBs at maximum load with evaporative cooling, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at maximum load with evaporative cooling, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at maximum load with evaporative cooling, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 110°F

- Operation of two GE 7FA.05s at maximum load with evaporative cooling, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at maximum load with evaporative cooling, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at maximum load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at maximum load with evaporative cooling, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at average load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at maximum load with evaporative cooling, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at maximum load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at average load, and the auxiliary boiler at an ambient temperature of 110°F
- Operation of two GE 7FA.05s at minimum load, two GE LMS-100PBs at minimum load, and the auxiliary boiler at an ambient temperature of 110°F

The stack parameters for each unit included in the load analysis are presented in Appendix B, Table 1. Stack parameters presented include source coordinates, elevation, stack height, temperature, exit velocity, and stack diameter.

The short-term and annual emission rates (in g/s and lb/hr) for each unit included in the load analysis are presented in Appendix B, Table 2. As shown, only the exhaust scenarios with combustion turbines operating at an average annual ambient temperature of 65.8°F include annual emission rates. Generally, the emission rates are based on the following:

- Short-term SO_2 emission rates for the GE 7FA.05s and GE LMS-100PBs are based on a maximum fuel sulfur content of 0.75 grain per 100 dry standard cubic feet of natural gas.
- Hourly CO and NO_2 emission rates for the GE 7FA.05s are based on cold startup events.
- Hourly CO and NO_2 emission rates for the GE LMS-100PBs are based on one startup, one shutdown, and the balance of the hour at steady-state operation.
- 8-hour CO emission rates for the GE 7FA.05s are based on one cold start, one warm start, two shutdowns, and the balance of the period at steady-state operation.
- 8-hour CO emission rates for the GE LMS-100PBs are based on two startups, two shutdowns, and the balance of the period at steady-state operation.

- Hourly emission rates for the auxiliary boiler are based on steady-state operation at 100 percent load.
- Annual emission rates for the GE 7FA.05s are based on 24 cold startups, 100 warm startups, 376 hot startups, 500 shutdowns, and 6,100 hours of steady-state operation.
- Annual emission rates for the GE LMS-100PBs are based on 350 hot startups, 350 shutdowns, and 1,150 hours of steady-state operation.
- Annual emission rates for the auxiliary boiler are based on 120 startups and 365 days of operation at 100 percent load.

The building parameters included in the load analysis are presented in Appendix B, Table 3. The building parameters include the presence of existing HGBS Units 1 and 2 in addition to those of the GE 7FA.05s and the GE LMS-100PBs.

The results for each scenario modeled through the load analysis are presented in Appendix B, Table 4. As with the emission rates, only the exhaust scenarios with combustion turbines operating at an average annual ambient temperature of 65.8°F include annual averaging period results. These results were used to identify the maximum impacts described below.

Table 4-3 presents a comparison of the maximum HBEP operational impacts to the CAAQS and National Ambient Air Quality Standards (NAAQS). As indicated, the maximum predicted CO, NO_2, SO_2, annual PM_{10}, and $PM_{2.5}$ operational impacts combined with the background concentrations will be below the ambient air quality standards for each averaging period. The 24-hour PM_{10} background concentration exceeds the CAAQS without adding the modeled concentration. As a result, the predicted impact combined with the background concentration will be greater than the CAAQS. However, as described in Section 5.1.7.3 of the PTA, HBEP emissions will be fully offset consistent with SCAQMD Rule 1303 through the SCAQMD internal offset bank under SCAQMD Rule 1304(a)(2). Therefore, impacts from operation will be less than significant.

TABLE 4-3

HBEP Operation Impacts Analysis – Maximum Modeled Impacts Compared to the Ambient Air Quality Standards

Pollutant	Averaging Time	Maximum Modeled Concentration, µg/m³	Background Concentration, µg/m³ [a]	Total Predicted Concentration, µg/m³	CAAQS, µg/m³	NAAQS, µg/m³
CO	1-hour	627	3,321	3,948	23,000	40,000
	8-hour	118	2,519	2,637	10,000	10,000
NO_2 [b]	1-hour (max)	94	142	236	339	—
	1-hour (98th percentile)[c]	—	—	126	—	188
	Annual	0.56	21.8	22.4	57	100
SO_2	1-hour (max)	5.69	20.2	25.9	655	—
	1-hour (99th percentile)[d]	4.80	8.80	13.6	—	196
	3-hour	4.94	20.2	25.1	—	1,300
	24-hour	1.66	5.20	6.86	105	365
PM_{10}	24-hour	5.38	51.0	56.4	50	150
	Annual	0.59	19.3	19.9	20	—
$PM_{2.5}$	24-hour (98th percentile)[e]	3.13	21.3	24.4	—	35
	Annual	0.59	8.60	9.19	12	12

[a] Background concentrations were the highest concentrations monitored during 2011 through 2013.

[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 (EPA, 2011) and 0.75 (EPA, 2005), respectively.

[c] The total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average, high-8th-high modeled concentration paired with 98th percentile seasonal hour-of-day background concentrations for 2010 through 2012.

[d] The total predicted concentration for the federal 1-hour SO_2 standard is the 5-year average, high-4th-high modeled concentration combined with the 3-year average, 99th percentile background concentration.

[e] The total predicted concentration for the federal 24-hour $PM_{2.5}$ standard is the 5-year average, high-8th-high modeled concentration combined with the 3-year average, 98th percentile background concentration.

4.2.1 Rule 2005

To demonstrate compliance with SCAQMD Rule 2005, each combustion unit was modeled individually using the stack parameters, emission rates, and building parameters from Appendix B, Tables 1, 2, and 3, respectively. The particular operational scenario selected for each combustion unit was chosen based on the load analysis results. In other words, only the parameters from the operational scenarios leading to the worst-case 1-hour, 1-hour federal, and annual NO_2 impacts were used. The results for each modeled scenario are presented in Appendix B, Table 5. These results were used to identify the maximum impacts described below.

The maximum modeled NO_2 concentrations are presented in Table 4-4 and are compared to the SCAQMD Rule 2005 significance threshold. Although each combustion emission unit was modeled, the results presented in Table 4-4 are only for the emission unit causing the highest modeled concentrations, in this case one combined-cycle turbine. The maximum modeled NO_2 concentrations were also added to representative background concentrations and compared to the state and federal ambient air quality standards for NO_2. Although the NO_2 concentrations per emission unit are greater than the SCAQMD Rule 2005 1-hour threshold, they are less than the ambient air quality standards and will be fully offset through the surrender of NO_X Regional Clean Air Incentives Market (RECLAIM) trading credits (RTCs). Therefore, the predicted NO_2 impacts from operation will be less than significant compared to SCAQMD Rule 2005.

TABLE 4-4
Rule 2005 Air Quality Thresholds and Standards Applicable to the HBEP (per emission unit)

Pollutant/Averaging Time	Maximum Modeled Concentration, μg/m³ [a]	Significant Threshold, μg/m³ [b]	Background Concentration, μg/m³ [c]	Total Predicted Concentration, μg/m³	CAAQS, μg/m³	NAAQS, μg/m³
NO_2 (1-hour)	60.3	20	142	202	339	—
NO_2 (Federal 1-hour)	62.0	N/A	98.2	160	—	188
NO_2 (Annual)	0.27	1.0	21.8	22.1	57	100

[a] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 (EPA, 2011) and 0.75 (EPA, 2005), respectively.
[b] Allowable change in air quality concentration per emission unit per SCAQMD Rule 2005, Appendix A.
[c] Background concentrations were the highest concentrations monitored during 2011 through 2013.

4.2.2 Regulation XVII (Prevention of Significant Deterioration [PSD])

To demonstrate compliance with SCAQMD Regulation XVII, operation of the HBEP was modeled using the stack parameters, emission rates, and building parameters from Appendix B, Tables 1, 2, and 3, respectively. As with the Rule 2005 assessment, the particular operational scenario selected for each combustion unit was chosen based on the load analysis results. In other words, only the parameters from the operational scenarios leading to the worst-case 1-hour and annual NO_2, 1-hour and 8-hour CO, and 24-hour and annual PM_{10} impacts were used. However, for 24-hour PM_{10}, the scenario contributing the maximum impact had both GE 7FA.05s operating at minimum load for 24 hours per day. Because this is an unlikely scenario, refined modeling was performed assuming each GE 7FA.05 would operate 20 hours per day at minimum load and 4 hours per day at average load. The results are presented in Appendix B, Table 6 and were used to identify the maximum impacts described below.

As shown in Table 4-5, the maximum predicted 1-hour CO, 8-hour CO, annual NO_2, 24-hour PM_{10}, and annual PM_{10} impacts from operation of the HBEP are below the Class II significance impact levels (SILs), Class II PSD Increment Standards, and significant monitoring concentrations. Therefore, additional analysis of 1-hour CO, 8-hour CO, annual NO_2, 24-hour PM_{10}, and annual PM_{10} impacts is not required. However, the maximum predicted 1-hour NO_2 impacts from operation of the HBEP exceed the Class II SIL, with a radius of impact with predicted concentrations greater than 7.52 micrograms per cubic meter (μg/m³) of 5.3

kilometers (km). Therefore, the cumulative impacts of the HBEP and competing sources were assessed for all receptors where the HBEP impacts alone exceeded the 1-hour NO_2 SIL, as described below.

TABLE 4-5
HBEP Predicted Impacts Compared to the PSD Air Quality Impact Standards

Pollutant/Averaging Time	Maximum Modeled Concentration, μg/m³	Significant Impact Level, μg/m³	PSD Class II Increment Standard, μg/m³	Significant Monitoring Concentration, μg/m³
CO (1-hour)	627	2,000	N/A	N/A
CO (8-hour)	118	500	N/A	575
NO_2 (1-hour)[a]	88.9	7.52[c]	N/A	N/A
NO_2 (Annual)[a]	0.56	1.0	25	14
PM_{10} (24-hour)[b]	4.93	5.0	30	10
PM_{10} (Annual)	0.59	1.0	17	N/A

[a] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 (EPA, 2011) and 0.75 (EPA, 2005), respectively.
[b] The 24-hour PM_{10} concentration is based on both GE 7FA.05 turbines operating 20 hours per day at minimum load and 4 hours per day at average load.
[c] The SIL for 1-hour NO_2 is based on SCAQMD correspondence.
N/A = not applicable (i.e., no standard)

To assess the cumulative impacts of the HBEP and competing sources, operation of the HBEP was modeled with concurrent operation of the competing sources listed below, which were approved by the SCAQMD on October 8, 2013[1]:

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

The stack parameters for each unit included in the competing source assessment are presented in Appendix B, Table 7. Stack parameters presented include source coordinates, elevation, stack height, temperature, exit velocity, and stack diameter for point sources and elevation, release height, and horizontal and vertical dimensions for volume sources. The 1-hour NO_2 emission rates (in g/s and lb/hr) for each unit included in the competing source assessment are presented in Appendix B, Table 8. Note that the stack parameters and emission rates used for the HBEP were selected based on the load analysis results. In other words, only the parameters from the operational scenarios leading to the worst-case federal 1-hour NO2 impacts were used. The building parameters were taken from Appendix B, Table 3. The competing source assessment results are presented in Appendix B, Table 9 and were used to identify the maximum impacts described below.

The receptor grid used in the competing source assessment modeling includes only those receptors in which the worst-case HBEP 1-hour NO_2 impacts exceeded the SIL. In other words, only those receptors where the five-year average of modeled impacts exceeding the SIL were included.

Table 4-6 presents a summary of the predicted cumulative 1-hour NO_2 impacts from operation of the HBEP and competing sources, as well as a comparison to the NAAQS. As shown, the predicted HBEP cumulative impacts, including a representative background NO_2 concentration, are below the NAAQS. Therefore, operation of the HBEP will not cause or contribute to a violation of the NAAQS.

[1] Source parameters and emissions rates for all competing sources, with the exception of HBGS, were provided by SCAQMD.

TABLE 4-6
HBEP and Competing Source Predicted 1-hour NO_2 Impacts Compared to the NAAQS

Pollutant	Averaging Time	Total Predicted Concentration, µg/m³ [a]	NAAQS, µg/m³
NO_2	1-hour	146	188

[a] The total predicted concentration for the federal 1-hour NO_2 standard is the 5-year average, high-8th-high modeled concentration paired with 98th percentile seasonal hour-of-day background concentrations for 2010 through 2012.

To assess potential impacts to Class I areas, operation of the HBEP was modeled using the stack parameters, emission rates, and building parameters from Appendix B, Tables 1, 2, and 3, respectively. As with the Rule 2005 assessment, the particular operational scenario selected for each combustion unit was chosen based on the load analysis results. In other words, only the parameters from the operational scenarios leading to the worst-case annual NO_2 and 24-hour and annual PM_{10} impacts were used. The results are presented in Appendix B, Table 10 and were used to identify the maximum impacts described below.

Table 4-7 presents a summary of the predicted annual NO_2, 24-hour PM_{10}, and annual PM_{10} impacts and a comparison to the PSD Class I Increment Standards. The predicted impacts from operation of the HBEP are below the SILs. Therefore, the HBEP would have a negligible impact at the more distant Class I areas.

TABLE 4-7
HBEP Predicted Impacts Compared to the Class I SIL and PSD Class I Increment Standards

Pollutant/Averaging Time	Maximum Modeled Concentration at 50 km, µg/m³	Significant Impact Level, µg/m³	PSD Class I Increment Standard, µg/m³
NO_2 (Annual)[a]	0.0062	0.1	2.5
PM_{10} (24-hour)	0.055	0.3	2.0
PM_{10} (Annual)	0.0067	0.2	1.0

[a] The annual NO_2 concentration includes an ambient NO_2 ratio of 0.75 (EPA, 2005).

4.2.3 Fumigation

To assess fumigation impacts, modeling was performed using the stack parameters and emission rates from Appendix B, Tables 1 and 2, respectively. As with the Rule 2005 assessment, the particular operational scenario selected for each combustion unit modeled was chosen based on the load analysis results. In other words, only the parameters from the operational scenarios leading to the worst-case 1-hour NO_2, 1-hour, 3-hour, and 24-hour SO_2, 1-hour and 8-hour CO, and 24-hour PM_{10} impacts were used. Table 4-8 presents a comparison of the potential HBEP operational fumigation impacts to the state and federal ambient air quality standards. As indicated, the CO, NO_2, SO_2, and PM_{10} concentrations combined with the background concentrations do not exceed the CAAQS or NAAQS, as applicable. Therefore, fumigation impacts of CO, NO_2, SO_2, and PM_{10} would be less than significant.

TABLE 4-8

HBEP Operation Impacts Analysis – Fumigation Impacts Analysis Results Compared to the Ambient Air Quality Standards

Pollutant	Averaging Time	SCREEN3 Fumigation Result, µg/m³	Background Concentration, µg/m³ [a]	Total Predicted Concentration, µg/m³	CAAQS, µg/m³	NAAQS, µg/m³
NO_2[b]	1-hour (max)	172	142	314	339	—
SO_2	1-hour (max)	10.5	20.2	30.7	655	—
	3-hour	9.45	20.2	29.7	—	1,300
	24-hour	4.20	5.20	9.40	105	—
CO	1-hour	980	3,321	4,301	23,000	40,000
	8-hour	204	2,519	2,723	10,000	10,000
PM_{10}	24-hour	15.5	51.0	66.5	N/A	150

[a] Background concentrations were the highest concentrations monitored during 2011 through 2013.

[b] The 1-hour NO_2 concentration includes an ambient NO_2 ratio of 0.80 (EPA, 2011).

N/A = not applicable (i.e., area is designated nonattainment such that a comparison to the standard is not required)

SECTION 5

Regulatory Evaluation

5.1 Laws, Ordinances, Regulations, and Standards

The Clean Air Act (CAA), implemented by the U.S. Environmental Protection Agency (EPA), requires major new and modified stationary sources of air pollution to obtain a construction permit prior to commencing construction through a program known as the federal New Source Review (NSR) program. The requirements of the NSR program are dependent on whether the air quality in the area where the new source (or modified source) is being located attains the National Ambient Air Quality Standards (NAAQS). The program that applies in areas that are in attainment of the NAAQS is the Prevention of Significant Deterioration (PSD). The program that applies to areas where the air does not meet the NAAQS (termed nonattainment areas) is the non-attainment NSR.

EPA implements the NSR program through regional offices. Arizona, California, Hawaii, Nevada, and specific Pacific trust territories are administrated out of the EPA Region IX office in San Francisco. EPA typically delegates its NSR, Title V, and Title IV authority to local air quality agencies that have sufficient regulatory structure to implement these programs consistent with requirements of the CAA and implementing regulations. The South Coast Air Quality Management District (SCAQMD) has been delegated several of these programs, including the authority to administer the PSD program.

The California Air Resources Board (ARB) was established by the state legislature in 1967 with the purpose of attaining and maintaining healthy air quality, conducting research into causes and solutions to air pollution, and addressing the impacts that motor vehicles have on air quality. To this end, ARB implements the following programs:

- Establish and enforce motor vehicle emission standards, including fuel standards.
- Monitor, evaluate, and set health-based air quality standards.
- Conduct research to solve air pollution problems.
- Establish toxic air contaminant (TAC) control measures.
- Oversee and assist local air quality districts.

Air pollution control districts were established based on meteorological and topographical factors. The districts were established to enforce air pollution regulations for the purpose of attaining and maintaining all state and federal ambient air quality standards (AAQS). The districts regulate air emissions by issuing air permits to stationary sources of air pollution in compliance with approved regulatory programs. Each district promulgates rules and regulations specific to air quality issues within its jurisdiction. The air emissions sources regulated by each district vary. The types of air pollution sources that might be regulated include manufacturers, power plants, refineries, gasoline service stations, and auto body shops.

The applicable laws, ordinances, regulations, and standards (LORS) and compliance with these requirements are discussed in more detail in the following sections.

5.2 Federal LORS

EPA promulgates and enforces federal air quality regulations, with Region IX administering the federal air programs in California. The federal CAA provides the legal authority to regulate air pollution from stationary sources. The applicable federal regulations are summarized in Table 5-1, along with the agency responsible for administration of the regulation.

TABLE 5-1
Applicable Federal Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Title 40 Code of Federal Regulations (CFR) Part 50	Establishes AAQS for criteria pollutants.	EPA Region IX	The Project Owner conducted a dispersion modeling analysis to determine if the Huntington Beach Energy Project (HBEP or Project) would exceed the state or federal AAQS. Dispersion modeling indicates the Project will not exceed the state or federal AAQS for the attainment pollutants during normal operations. Nonattainment pollutant emissions will be mitigated consistent with the SCAQMD's State Implementation Plan-Approved NSR program.
Title 40 CFR Part 51, NSR (SCAQMD Regulation XIII)	Requires pre-construction review and permitting of new or modified stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of AAQS.	SCAQMD with EPA Region IX Oversight	Requires NSR facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which ambient concentration levels are higher than NAAQS. The NSR requirements are implemented at the local level with EPA oversight (SCAQMD Regulation XIII). A Permit to Construct (PTC) and Permit to Operate (PTO) application will be obtained from SCAQMD prior to construction of the Project. As a result, the compliance requirements of 40 CFR 51 will be met.
Title 40 CFR Part 52, PSD	The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified in areas classified as attainment, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I Areas (e.g., national parks and wilderness areas).	SCAQMD with EPA Region IX Oversight	The PSD requirements apply on a pollutant-specific basis to any project that is a new major stationary source or a major modification to an existing major stationary source. SCAQMD classifies an unlisted source (which is not in the specified 28 source categories) that emits or has the potential to emit 250 tons per year (tpy) of any pollutant regulated by the CAA as a major stationary source. For listed sources, the threshold is 100 tpy. Oxides of nitrogen (NO_x), volatile organic compounds (VOC), or sulfur dioxide (SO_2) emissions from a modified major source are subject to PSD if the cumulative emission increases for either pollutant exceeds 40 tpy. In addition, a modification at a non-major source is subject to PSD if the modification itself would be considered a major source. In May 2010, EPA issued the greenhouse gas (GHG) permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule), in which EPA defined six GHG pollutants (collectively combined and measured as carbon dioxide equivalent [CO_2e]) as NSR-regulated pollutants. Under the GHG Tailoring Rule, new projects that emit GHG pollutants above certain threshold levels would be subject to PSD permitting beginning in July 2011. However, in July 2014, the U.S. Supreme Court ruled that EPA could not regulate GHG emissions alone. As a result, new sources with a GHG potential to emit (PTE) equal to or greater than 100,000 tpy of CO_2e are no longer required to obtain a PSD permit specifically for GHG emissions. If the new source would require a PSD permit as a result of criteria pollutant PTE, a Best Available Control Technology (BACT) analysis to evaluate GHG emissions control would still be required. The HBEP is a natural-gas-fired, combined-cycle and simple-cycle, air-cooled electrical generating facility and would be considered one of the 28 source categories. Therefore, the emission rates were compared to the 100 tpy threshold. As shown in Table 5.1-15 of the Petition to Amend (PTA), the emission increase in carbon monoxide (CO) and NO_x would exceed the 100 tpy threshold per pollutant. Therefore, the HBEP would be subject to PSD

TABLE 5-1
Applicable Federal Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
			analysis requirements for CO and NO_x. Since the Project exceeds the PSD thresholds for several criteria pollutants, a BACT analysis for GHG emissions control is required. A PSD application was submitted to the SCAQMD and EPA as part of the PTA, which included a BACT analysis for GHG emissions control.
Title 40 CFR Part 60, Subpart KKKK (SCAQMD Regulation IX)	Establishes national standards of performance for new or modified facilities in specific source categories.	SCAQMD with EPA Region IX Oversight	40 CFR 60 Subpart KKKK – NO_x Emission Limits for New Stationary Combustion Turbines applies to all new combustion turbines that commence construction, modification, or reconstruction after February 18, 2005. The Rule requires natural-gas-fired turbines with a heat input greater than 850 million British thermal units per hour (MMBtu/hr) to meet an NO_x emission limit of 15 part(s) per million (ppm) at 15 percent oxygen (O_2), and an SO_2 limit of 0.060 pound(s) per million British thermal unit (lb/MMBtu). Alternatively, a fuel sulfur limit of 500 part(s) per million by weight (ppmw) could be met. Stationary combustion turbines regulated under this subpart would be exempt from the requirements of Subpart GG. The proposed combined-cycle and simple-cycle turbines will use dry low NO_x combustors with selective catalytic reduction (SCR) systems and pipeline-quality natural gas and will comply with both the NO_x and SO_2 limits. The NO_x and SO_2 emissions from the combined-cycle turbines will be 2 ppm at 15 percent O_2 and 0.0022 lb/MMBtu, respectively. The NO_x and SO_2 emissions from the simple-cycle turbines will be 2.5 ppm at 15 percent O_2 and 0.0018 lb/MMBtu, respectively. The certified NO_x Continuous Emission Monitoring System (CEMS) will ensure compliance with the standard. Records of natural gas use and fuel sulfur content will ensure compliance with the SO_2 limit.
Title 40 CFR Part 60, Subpart Dc (SCAQMD Regulation IX)	Establishes national standards of performance for new or modified facilities in specific source categories.	SCAQMD with EPA Region IX Oversight	40 CFR 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. Because the HBEP's auxiliary boiler will be fired exclusively on natural gas, the Project Owner will only be required to maintain monthly fuel consumption records for a minimum of two years.
Title 40 CFR Part 60, Subpart TTTT	Establishes a new source performance standard for electrical generating facilities.	SCAQMD with EPA Region IX Oversight	EPA promulgated New Source Performance Standard Subpart TTTT, which includes two potentially applicable GHG emission limits for newly constructed combustion turbines. A newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency times its potential electric output as net-electric sales on a 3-year rolling average basis and combusts more than 90 percent natural gas on a heat input basis on a 12-operating-month rolling average basis must meet a limit of 450 kilograms (kg) of CO_2 per MWh of gross energy output (1,000 pounds [lb] of CO_2 per MWh), or 470 kg of CO_2 per MWh of net energy output (1,030 lb CO_2/MWh). A newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency times its potential electric output or less as net-electric sales on a 3-year rolling average basis and combusts more than 90 percent natural gas on a heat input basis on a

TABLE 5-1
Applicable Federal Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
			12-operating-month rolling average basis must meet a limit of 50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2 per million British thermal units [MMBtu]). The applicable emission standard depends on whether a combustion turbine sells more electricity than its potential electrical output, which is calculated by multiplying the design efficiency and the potential electrical output, and combusts more than 90 percent natural gas. Assuming the combined-cycle power block will generate more electricity than the potential electrical output, the HBEP will need to comply with the 1,000 lb of CO_2 per MWh emission limit. The HBEP is exclusively fueled by natural gas with a combined-cycle power block design efficiency of approximately 56 percent. The HBEP's combined-cycle GHG efficiency is estimated at 766 lb of CO_2 per MWh (net), assuming an 8 percent performance degradation, which clearly complies with Subpart TTTT's emission limit of 1,000 lb of CO_2 per MWh. The HBEP simple-cycle power block design efficiency is 41 percent and the potential HBEP simple-cycle power block's electrical output threshold is 718,320 MWh-Net (based on the design efficiency of 41 percent and the net electrical output of 200 MW for 8,760 hours per year). The HBEP simple-cycle power block's potential annual net electric sales are 258,924 MWh-Net, assuming 200 MWs-Net of generation and 1,284 hours per year of operation (1,150 operating hours plus 58 startup and 76 shutdown hours). Since the annual net electric sales are less than the electric output threshold, the HBEP simple-cycle power block must comply with Subpart TTTT emission limit of 50 kg CO_2 per GJ of heat input (120 lb CO_2/MMBtu). As a natural-gas fired facility, the HBEP is expected to emit CO_2 at a rate of 117 lb CO_2/MMBtu, thereby complying with the applicable emission limit in Subpart TTTT.
Title 40 CFR Part 63	Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs) or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established from facilities in specific categories.	SCAQMD with EPA Region IX Oversight	40 CFR 63—National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories establishes emission standards to limit emissions of HAPs from specific source categories for Major HAP sources. Sources subject to 40 CFR 63 requirements must either use the maximum achievable control technology (MACT), be exempted under 40 CFR 63, or comply with published emission limitations. The potential NESHAP applicable to the Project is Subpart YYYY, which sets a formaldehyde emission limit or an operational limit of 91 part(s) per billion by volume (ppbv) for turbines. Note that Subpart JJJJJJ is not applicable to the Project because the auxiliary boiler will be fired exclusively with natural gas. Projects would be subject to the 40 CFR 63 requirements if the HAP PTE is greater or equal to 25 tpy for combined HAPs and 10 tpy for individual HAPs. HBEP is not expected to exceed these thresholds and is not subject to NESHAPs,
Title 40 CFR Part 64 (Compliance Assurance Monitoring [CAM] Rule)	Establishes onsite monitoring requirements for emission control systems.	SCAQMD with EPA Region IX Oversight	40 CFR 64—CAM requires facilities to monitor the operation and maintenance of emissions control systems and report any control system malfunctions to the appropriate regulatory agency. If an emission control system is not working properly, the CAM Rule also requires a facility to take action to correct the control system malfunction. The CAM Rule applies to emissions units with uncontrolled PTE levels greater than applicable major source thresholds.

TABLE 5-1
Applicable Federal Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
			Emission control systems governed by Title V operating permits requiring continuous compliance determination methods are generally compliant with the CAM Rule. The HBEP's CTGs will have emission control systems for NO_x and CO (SCR and oxidation catalyst); the HBEP's auxiliary boiler will have emission control systems for NO_x (SCR). However, emissions of NO_x and CO from the CTGs and NO_x from the auxiliary boiler would be directly measured by CEMS. Therefore, the HBEP is exempt from the CAM provisions based on the exemption in 40 CFR 64.2(b)(vi) and SCAQMD Regulation XX for NO_x.
Title 40 CFR Part 70 (SCAQMD Regulation XXX)	CAA Title V Operating Permit Program	SCAQMD with EPA Region IX Oversight	40 CFR 70—Operating Permits Program requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. The requirements of 40 CFR 70 apply to facilities that are subject to New Source Performance Standards (NSPS) requirements and are implemented at the local level through SCAQMD Regulation XXX. According to Regulation XXX, Rule 3001, a facility would be required to submit a Title V application if the facility has a PTE greater than 10 tpy NO_x or VOC, 100 tpy of SO_2, 50 tpy of CO, or 70 tpy of PM_{10} of the HAP PTE is greater or equal to 25 tpy for combined HAPs and 10 tpy for individual HAPs. The HBEP will exceed the Title V thresholds listed in SCAQMD Rule 3001. As a result, the HBEP submitted an application to modify the existing Title V permit.
Title 40 CFR Part 72 (SCAQMD Regulation XXXI)	CAA Acid Rain Program	SCAQMD with EPA Region IX Oversight	40 CFR 72—Acid Rain Program establishes emission standards for SO_2 and NO_x emissions from electric generating units through the use of market incentives, requires sources to monitor and report acid gas emissions, and requires the acquisition of SO_2 allowances sufficient to offset SO_2 emissions on an annual basis. An acid rain facility, such as the HBEP, must also obtain an acid rain permit as mandated by Title IV of the CAA. A permit application must be submitted to SCAQMD at least 24 months before operation of the new units commences. The application must present all relevant sources at the facility, a compliance plan for each unit, applicable standards, and estimated commencement date of operation. The necessary Title IV applications will be submitted as part of the permitting process.

5.3 State LORS

ARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the California Ambient Air Quality Standards (CAAQS); to review the operations of the local air pollution control districts; and to review and coordinate preparation of the State Implementation Plan for achievement of the NAAQS.

The California Health and Safety Code, Section 41700 prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, that endanger the comfort, repose, health, or safety of the public, or that damage business or property.

In August 2006, the California legislature passed Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006. AB 32 requires California resource agencies to establish a comprehensive program of regulatory and market mechanisms to achieve reductions in GHG. The HBEP will be subject to AB 32, and will be required to comply with all final rules, regulations, emissions limitations, emission reduction measures, or market-based compliance mechanisms adopted under AB 32. ARB promulgated a Cap and Trade regulation to limit greenhouse gas (GHG) emissions and to develop a market-based compliance mechanism for the creation, sale, and use of GHG allowances.

In addition to AB 32, Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) was signed into law on September 29, 2006. The law limits long-term investments in base load generation by the state's utilities to power plants that meet an emissions performance standard (EPS) jointly established by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC). In response, the CEC has designed regulations that establish a standard for base load generation owned by, or under long-term contract to, publicly owned utilities of 1,100 pound(s) carbon dioxide per megawatt-hour (lb CO_2/MWh). Base load generation is defined as electricity generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent. The permitted capacity factor for the HBEP will be approximately 50 percent. Therefore, as a non-base load facility, the HBEP is not subject to the EPS; however, despite its inapplicability, the HBEP's state-of-the-art, efficient combined-cycle and simple-cycle configurations nevertheless satisfy this requirement, emitting 709 lb CO_2/MWh and 1,075 lb CO_2/MWh, respectively.

The state has promulgated numerous laws and regulations at the state level (Toxic Air Contaminants and Air Toxic Hot Spots) which are effectuated at the local level by the air districts. A discussion of these state and local LORS is presented in Tables 5-2 and 5-3, respectively.

TABLE 5-2
Applicable State Laws, Ordinances, Regulations, and Standards for the Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
California Health & Safety Code, Section 41700	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	SCAQMD with ARB Oversight	The CEC Conditions of Certification and the air quality management district PTC processes are developed to ensure that no adverse public health effects or public nuisances result from operation of the Project.
California Assembly Bill 32 – Global Warming Solutions Act of 2006 (AB 32)	The purpose is to reduce carbon emissions within the state by approximately 25 percent by the year 2020.	SCAQMD with ARB Oversight	Requires ARB to develop regulations to limit and reduce GHG emissions.
California Code of Regulations, Title 17, Article 5	Establishes GHG limitations, reporting requirements, and a Cap and Trade offsetting program.	ARB	ARB has promulgated a Cap and Trade regulation that limits or caps GHG emissions and requires subject facilities to acquire GHG allowances. HBEP GHG emissions have been estimated and the Project Owner will report emissions and acquire allowances and offsets consistent with these regulations.
California Senate Bill 1368 – Emissions Performance Standards (SB 1368)	The law limits long-term investments in base load generation by the state's utilities to power plants that meet an EPS jointly established by the CEC and CPUC.	CEC with ARB Oversight	CEC has designed regulations that establish a standard for base load generation owned by, or under long-term contract to, publicly owned utilities of 1,100 lb CO_2/MWh. The HBEP combined-cycle and simple-cycle units will emit 709 and 1,075 lb CO_2/MWh, respectively.

5.4 Local LORS

When the state's air pollution statutes were reorganized in the mid-1960s, local districts were required to be established in each county of the state. There are three different types of districts: county, regional, and unified. In addition, special air quality management districts, with more comprehensive authority over non-vehicular sources as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California, including SCAQMD. Air quality management districts have principal responsibility for developing plans for meeting the NAAQS and CAAQS; for developing control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards; for implementing permit programs established for the construction, modification, and operation of sources of air pollution; and for enforcing air pollution statutes and regulations governing non-vehicular sources.

SCAQMD plans define the proposed strategies, including stationary source control measures and NSR rules, whose implementation will attain the CAAQS. The relevant stationary source control measures and NSR requirements are presented in Table 5-3.

TABLE 5-3
Applicable Local Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Assessment
SCAQMD Rule 201	Establishes an orderly procedure for the review of new and modified sources of air pollution through the issuance of permits.	SCAQMD	Rule 201 specifies that any facility installing nonexempt equipment that causes or controls the emission of air pollutants must first obtain a PTC from the SCAQMD. SCAQMD has three separate preconstruction review programs for new or modified sources of criteria pollutant emissions: Regulation XIII (NSR), Regulation XVII (PSD), and Rule 2005 (NSR for Regional Clean Air Incentives Market [RECLAIM]). Section 5.1 of the PTA included an assessment of the air quality impacts in accordance with Regulation XIII, Regulation XVII, and Rule 2005. The completed SCAQMD PTC application forms were included in Appendix 5.1E of the PTA.
SCAQMD Rule 201.1	Incorporates the permit conditions in federally issued permits to construct.	SCAQMD	A person constructing and/or operating equipment or an agricultural permit unit, pursuant to a PTC issued by the EPA, shall construct the equipment or agricultural permit unit in accordance with the conditions set forth in that permit, and shall operate the equipment or agricultural permit unit at all times in accordance with such conditions. A federal PSD permit will be obtained for the HBEP. The Project Owner will comply with the permit conditions established in the PSD permit.
SCAQMD Rule 212	Establishes standards for approving permits and issuing public notice.	SCAQMD	Rule 212 requires public notification if a. Any new or modified permit unit, source under Regulation XX, or equipment under Regulation XXX that may emit air contaminants is located within 1,000 feet from the outer boundary of a school; or b. Any new or modified facility which has onsite emission increases exceeding any of the daily maximums specified in subdivision (g) of this rule; or c. Any new or modified permit unit, source under Regulation XX, or equipment under Regulation XXX with increases in emissions of toxic air contaminants, for which the Executive Officer has made a determination that a person may be exposed to a maximum individual cancer risk (MICR) is greater than, one in one million (1×10^{-6}), due to a project's proposed construction, modification, or relocation for facilities with more than one permitted equipment unless the applicant can show the total facility-wide MICR is below ten in a million (10×10^{-6}). The HBEP will be greater than 1,000 feet from the outer boundary of a school and the predicted total facility-wide MICR is less than ten in one million. However, the onsite emissions will exceed the daily maximums listed in subdivision (g) of this Rule. Therefore, a public notice consistent with the requirements outlined in Rule 212 will be issued. The process for public notification and comment will include all of the applicable provisions of 40 CFR 51.161(b) and 40 CFR 124.10.
SCAQMD Rule 218	Establishes requirements for a CEMS.	SCAQMD	The owner or operator of any equipment subject to this Rule shall provide, properly install, operate, and maintain in calibration and good working order a certified CEMS to measure the concentration and/or emission rates, as applicable, of air contaminants and diluent gases, flow rates, and other required parameters. Each gas turbine and the auxiliary boiler will be equipped with a CEMS. These units will comply with all applicable requirements of Rule 218, Regulation XX (NO_x RECLAIM), and Title IV (Acid Rain – 40 CFR 75).
SCAQMD Rule 401	Establishes limits for visible emissions from stationary sources.	SCAQMD	Rule 401 prohibits visible emissions as dark as or darker than Ringlemann No. 1 for periods greater than 3 minutes in any hour. Natural gas will be the only fuel fired in the natural gas turbines and auxiliary boiler. Therefore, the Project will not create visible emissions as dark as or darker than Ringlemann No. 1.
SCAQMD Rule 402	Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property.	SCAQMD	A person shall 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 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. The CEC Conditions of Certification and the SCAQMD PTC process are designed to ensure that the operation of the Project will not cause a public nuisance.
SCAQMD Rule 403	Establishes requirements to reduce the amount of particulate matter (PM) entrained in the ambient air as a result of man-made fugitive dust sources.	SCAQMD	Rule 403 requires the implementation of best available control measures to minimize fugitive dust emissions and prohibits visible dust emissions beyond the property line, a 50 micrograms per cubic meter ($\mu g/m^3$) incremental increase in particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) concentrations across a facility as measured by upwind and downwind concentrations, and track-out of bulk material onto public, paved roadways. The Project will implement best available control measures as part of the Stormwater Pollution Prevention Plan to minimize fugitive dust emissions during construction and operation.
SCAQMD Rule 404	Establishes limits for PM matter emission concentrations.	SCAQMD	A person shall not discharge into the atmosphere from any source PM in excess of the concentration at standard conditions listed in Rule 404. However, per Rule 404.c, this Rule does not apply to emissions resulting from the combustion of liquid or gaseous fuels in steam generators or gas turbines. Because the gas turbines and auxiliary boiler will combust natural gas only, Rule 404 is not applicable.
SCAQMD Rule 405	Establishes limits for PM mass emission rates.	SCAQMD	Emission rate limits are based upon the process weight (fuel burned) per hour. Natural gas will be the only fuel fired in the natural gas turbines and auxiliary boiler. Therefore, the Project will comply with the Rule 405 PM emission limits.
SCAQMD Rule 407	Establishes limits for CO and oxides of sulfur (SO_x) emissions from stationary sources.	SCAQMD	Rule 407 prohibits CO and SO_x emissions in excess of 2,000 and 500 ppm, respectively, from any source. The CO emissions from the combined-cycle turbines, simple-cycle turbines, and auxiliary boiler will be less than 2 ppm, 4 ppm, and 50 ppm, respectively. Therefore, the Project meets the CO limit. In addition, equipment that complies with the requirements of Rule 431.1 is exempt from the SO_x limit. Since the facility will comply with Rule 431.1, the SO_x provisions of Rule 407 are not applicable.

TABLE 5-3
Applicable Local Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Assessment
SCAQMD Rule 409	Establishes limits for PM emissions from fuel combustion sources.	SCAQMD	Rule 409 prohibits PM emissions in excess of 0.1 grains per cubic foot of gas at 12 percent carbon dioxide (CO_2) at standard conditions. Natural gas will be the only fuel fired in the natural gas turbines and auxiliary boiler. Therefore, the Project will comply with the Rule 409 PM emission limits.
SCAQMD Rule 431.1	Establishes limits for the sulfur content of gaseous fuels to reduce SO_x emissions from stationary combustion sources.	SCAQMD	Rule 431.1 limits the sulfur content of natural gas calculated as hydrogen sulfide (H_2S) to be less than 16 part(s) per million by volume (ppmv). The sulfur content of the natural gas will be less than 0.75 grains of sulfur per 100 dry standard cubic feet (dscf) of natural gas or 12.6 ppmv. Therefore, the Project will comply with the Rule 431.1 requirement.
SCAQMD Rule 474	Establishes limits for emissions of NO_x from stationary combustion sources.	SCAQMD	Per Rule 2001, NO_x RECLAIM facilities are exempt from the provisions of Rule 474. Since the Project will be a NO_x RECLAIM facility, Rule 474 is not applicable.
SCAQMD Rule 475	Establishes limits for combustion contaminant (PM) emissions from subject equipment.	SCAQMD	Rule 475 prohibits PM emissions that exceed both 11 pound(s) per hour (lb/hr) (per emission unit) and 0.01 grains per dry standard cubic foot (gr/dscf) at 3 percent O_2. The combined-cycle turbines' PM emission rate will be 9.0 lb/hr and less than 0.01 gr/dscf. Similarly, the simple-cycle turbines' PM emission rate will be 6.24 lb/hr and less than 0.01 gr/dscf.
SCAQMD Rule 476	Establishes limits for NO_x and PM emissions from steam generating equipment with a maximum heat input rating exceeding 50 MMBtu/hr.	SCAQMD	Per Rule 2001, NO_x RECLAIM facilities are exempt from the NO_x requirements for this rule. Therefore, only the PM provisions of this rule will apply. The combined-cycle turbines' PM emission rate will be 9.0 lb/hr and less than 0.01 gr/dscf. Similarly, the simple-cycle turbines' PM emission rate will be 6.24 lb/hr and less than 0.01 gr/dscf.
SCAQMD Rule 53	Establishes limits for emissions of sulfur compounds (SO_x) from stationary sources in Orange County.	SCAQMD	A person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge 500 parts per million by volume (ppmv), calculated as SO_2. The use of low sulfur natural gas will result in SO_2 concentrations significantly less than 500 pppmv.
SCAQMD Regulation IX, Permits (40 CFR 60)	Establishes national standards of performance for new or modified facilities in specific source categories.	SCAQMD with EPA Region IX Oversight	See 40 CFR 60 (Table 3-1) to review applicability and the compliance assessment.
SCAQMD Regulation X, Permits (40 CFR 63)	Establishes national emission standards to limit emissions of HAPs or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established from facilities in specific categories.	SCAQMD with EPA Region IX Oversight	See 40 CFR 63 (Table 3-1) to review applicability and the compliance assessment.
SCAQMD Rule 1134	Establishes limits for emissions of NO_x from the stationary gas turbines.	SCAQMD	Per Rule 2001, NO_x RECLAIM facilities are exempt from the provisions of Rule 1134. Therefore, Rule 1134 is not applicable to the Project.
SCAQMD Rule 1135	Establishes limits for emissions of NO_x from the electricity generating systems.	SCAQMD	Per Rule 2001, NO_x RECLAIM facilities are exempt from the provisions of Rule 1135. Therefore, Rule 1135 is not applicable to the Project.
SCAQMD Rule 1146	Establishes limits for emissions of NO_x from industrial, institutional, and commercial boilers, steam generators, and process heaters.	SCAQMD	Per Rule 2001, NO_x RECLAIM facilities are exempt from the provisions of Rule 1146. Therefore, Rule 1146 is not applicable to the Project.

TABLE 5-3
Applicable Local Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Assessment
SCAQMD Rule XIII, Permits (NSR)	Provides for the review of new and modified sources and provide mechanisms, including the use of BACT and emission offsets, by which authorities to construct such sources may be granted for non-RECLAIM pollutants.	SCAQMD	Rule 1303(a) – BACT: BACT shall be applied to any new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia. The BACT requirements of Rule 1303 apply regardless of any modeling or offset exemption in Rule 1304. Therefore, a complete top-down BACT analysis was conducted for emissions of CO, VOC, SO_2, PM_{10}, particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and GHG. The proposed BACT emission limits are presented in Appendix A. A BACT analysis for NO_x was conducted as part of compliance with Rule 2005. Rule 1303(b)(1) – Modeling: As part of the NSR permit approval process, an air quality dispersion analysis must be conducted using a mass emissions-based analysis contained in the Rule or an approved dispersion model to evaluate impacts of increased criteria pollutant emissions from any new or modified facility on ambient air quality. The Project Owner conducted air dispersion modeling to demonstrate that the auxiliary boiler will not cause a violation, or make significantly worse an existing violation, or any state or federal AAQS. The gas turbines are exempt from modeling requirements per Rule 1304, with the exception of Regulation XX pollutants. Rule 1303(b)(2) – Offsets: Unless exempt from offsets requirements pursuant to Rule 1304, emission increases shall be offset by either Emission Reduction Credits approved pursuant to Rule 1309, or by allocations from the Priority Reserve in accordance with the provisions of Rule 1309.1, or allocations from the Offset Budget in accordance with the provisions of Rule 1309.2. Offset ratios shall be 1.2-to-1.0 for Emission Reduction Credits and 1.0-to-1.0 for allocations from the Priority Reserve, except for facilities not located in the South Coast Air Basin, where the offset ratio for Emission Reduction Credits only shall be 1.2-to-1.0 for VOC, NO_x, SO_x and PM_{10} and 1.0-to-1.0 for CO. The Project Owner will provide sufficient VOC and PM_{10} Emission Reduction Credits to offset the auxiliary boiler's emissions at a 1.2-to-1.0 ratio; NO_x emissions will be addressed through Regulation XX. The gas turbines are exempt from offset requirements per Rule 1304, with the exception of Regulation XX pollutants. Rule 1303(b)(3) – Sensitive Zone Requirements: Unless credits are obtained from the Priority Reserve, facilities located in the South Coast Air Basin are subject to the Sensitive Zone requirements specified in California Health & Safety Code Section 40410.5. The HBEP is located in Zone 1. Therefore, the Project Owner will obtain Emission Reduction Credits from Zone 1 only to offset emissions from the auxiliary boiler. The gas turbines are exempt from offset requirements per Rule 1304, with the exception of Regulation XX pollutants. Rule 1303(b)(4) – Facility-wide Compliance: The Project will complies with all applicable rules and regulations of the SCAQMD. Rule 1303(b)(5)(A) – Alternative Analysis: Conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with that project. Rule 1303(b)(5)(B) – Statewide Compliance: Demonstrate prior to the issuance of a PTC that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the CAA. The Project Owner has certified in SCAQMD Form 400-A that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. Rule 1303(b)(5)(C) – Protection of Visibility: Conduct a modeling analysis for plume visibility in accordance with the procedures specified in Appendix B if the net emission increase from the new or modified source exceeds 15 tpy of PM_{10} or 40 tpy of NO_x; and the location of the source, relative to the closest boundary of a specified federal Class I area, is within 28 kilometers. Emissions of PM_{10} and NO_x will exceed the emissions thresholds but the distance to the nearest Class I area is approximately 70 kilometers. Therefore, a visibility analysis is not required. Rule 1303(b)(5)(D) – Compliance through California Environmental Quality Act (CEQA): Because the CEC certification process is similar to the CEQA process, the applicable CEQA requirements have been addressed in the PTA. Rule 1304.1 – Electrical Generating Fee for Use of Offset Exemption: Requires the payment of fees to generate air quality improvements within the project area consistent with SCAQMD's approved Air Quality Management Plan.

TABLE 5-3
Applicable Local Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Assessment
SCAQMD Rule 1325, Permits (Federal $PM_{2.5}$ NSR)	Provides for the review of new and modified sources and mechanisms, including the use of lowest achievable emissions rate (LAER) and emission offsets, by which authorities to construct such sources may be granted for $PM_{2.5}$.	SCAQMD	The Executive Officer shall deny the permit for a new major polluting facility; or major modification to a major polluting facility; or any modification to an existing facility that would constitute a major polluting facility in and of itself (i.e., the PTE is 100 tpy or more of $PM_{2.5}$ or its precursors), unless each of the following requirements is met: (A) LAER is employed for the new or relocated source or for the actual modification to an existing source; and (B) Emission increases shall be offset at a ratio of 1.1-to-1.0 for $PM_{2.5}$ and at the ratio required in Regulation XIII or Rule 2005 for NO_x and SO_2, as applicable; and (C) Certification is provided by the owner/operator that all major sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the CAA; and (D) An analysis is conducted of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstration made that the benefits of the proposed project outweigh the environmental and social costs associated with that project. The HBEP will not exceed the 100-tpy threshold for $PM_{2.5}$ (or $PM_{2.5}$ precursors on a per-pollutant basis). Therefore, Rule 1325 is not applicable.
SCAQMD Rule 1401, Permits (Toxics NSR)	Provides for the review of new and modified sources of TAC emissions to evaluate potential public exposure and health risk, to mitigate potentially significant health risks resulting from these exposures, and to provide net health risk benefits by improving the level of control when existing sources are modified or replaced.	SCAQMD	Best Available Control Technology for Toxics (T-BACT) shall be applied to any new or modified source of TACs where the source risk is a cancer risk greater than one in one million (1×10^{-6}), a chronic hazard index greater than 1.0, or an acute hazard index greater than 1.0. The predicted MICR at the maximum exposed individual resident (MEIR) and maximum exposed individual worker (MEIW) for the Project are 6.33 and 0.43 in one million, respectively. The maximum predicted chronic and acute hazard indices for the Project are 0.036 and 0.080, respectively. These values are below the PTC or PTO facility thresholds for cancer risk of ten in one million and the chronic and acute hazard index of 1.0. The predicted MICR at the MEIR and MEIW are 3.29 and 0.26, respectively, for an individual combined-cycle turbine; 0.090 and 0.0039, respectively, for an individual simple-cycle turbine; and 0.18 and 0.057, respectively, for the auxiliary boiler. Although the combined-cycle turbine cancer risks exceed the individual unit threshold of one in one million, the HBEP will employ emission controls considered to be T-BACT. Therefore, the HBEP will comply with Rule 1401.
SCAQMD Rule 1403, Permits (Asbestos Removal)	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	The Project Owner will comply with the requirements outlined in Rule 1403 prior to and during the removal of asbestos-containing materials.
SCAQMD Regulation XVII, Permits (PSD)	Allows new sources of air pollution to be constructed, or existing sources to be modified in areas classified as attainment, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I Areas (e.g., national parks and wilderness areas).	SCAQMD with EPA Region IX Oversight	See 40 CFR 52 (Table 3-1) to review applicability and the compliance assessment.

TABLE 5-3
Applicable Local Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Assessment
SCAQMD Regulation XX, Permits (NO_x RECLAIM)	Provides for the review of new and modified sources and provides mechanisms, including the use of BACT and emission offsets, by which authorities to construct such sources may be granted for RECLAIM pollutants.	SCAQMD	Rule 2005(b)(1)(A) – BACT: BACT shall be applied to any new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia. A complete top-down BACT analysis was conducted for emissions of NO_x. The proposed BACT emission limits are presented in Appendix A. A BACT analysis for CO, VOC, SO_2, PM_{10}, $PM_{2.5}$, and GHG was conducted as part of compliance with Rule 1303. Rule 2005(b)(1)(B) – Modeling: As part of the NSR permit approval process, an air quality dispersion analysis must be conducted for NO_x using a mass emissions-based analysis contained in the rule or an approved dispersion model, to evaluate impacts of increased NO_x emissions from any new or modified facility on ambient air quality. An air quality dispersion analysis was conducted for NO_x using the AERMOD dispersion model. Rule 2005(b)(2) – Offsets: NO_x emission increases shall be offset using RECLAIM trading credits at a ratio of 1.0-to-1.0. The HBEP will participate in the NO_x RECLAIM program and will secure the necessary offsets as outlined in Section 5.1.7 of the PTA. Rule 2005(e) – Trading Zone Requirements: Any increase in an annual allocation to a level greater than the facility's starting plus non-tradable allocations, and all emissions from a new or relocated facility, must be fully offset by obtaining RTCs originated in one of the two trading zones. A facility in Zone 1 may only obtain RTCs from Zone 1. A facility in Zone 2 may obtain RTCs from either Zone 1 or 2, or both. The HBEP is located in Zone 1. Therefore, the Project Owner will obtain RTCs from Zone 1 only. Rule 2005(g)(1) – Statewide Compliance: Demonstrate, prior to the issuance of a PTC, that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the CAA. The Project Owner has certified in SCAQMD Form 400-A that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. Rule 2005(g)(2) – Alternative Analysis: Conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with that project. The Project Owner has conducted a comparative evaluation of alternative sites as part of the PTA process and has concluded that the benefits of providing grid reliability and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility. Rule 2005(g)(3) – Compliance through CEQA: Because the CEC certification process is similar to the CEQA process, the applicable CEQA requirements have been addressed in the PTA. Rule 2005(g)(4) – Protection of Visibility: Conduct a modeling analysis for plume visibility in accordance with the procedures specified in Appendix B if the net emission increase from the new or modified source exceeds 40 tpy of NO_x; and the location of the source, relative to the closest boundary of a specified federal Class I area, is within 28 kilometers. Emissions of NO_x will exceed the emissions thresholds; however, the distance to the nearest Class I area is approximately 70 kilometers. Therefore, a visibility analysis is not required. Rule 2005(h) – Public Notice: The applicant shall provide public notice, if required, pursuant to Rule 212 The Project Owner will comply with the requirements for Public Notice outlined in Rule 212 Rule 2005(i) – Rule 1401 Compliance: All new or modified sources shall comply with the requirements of Rule 1401. The Project Owner will comply with the requirements of Rule 1401 as demonstrated in Section 5.9 of the PTA. Rule 2005(j) – Compliance with State and Federal NSR: The Project will comply with all applicable rules and regulations of the SCAQMD.
SCAQMD Regulation XXX, Permits (Title V)	Implements the operating permit requirements of Title V of the CAA as amended in 1990.	SCAQMD with EPA Region IX Oversight	See 40 CFR 70 (Table 3-1) to review applicability and the compliance assessment.
SCAQMD Rule 3008, Title V Permits (PTE Limitations)	Exempts low-emitting facilities with actual emissions below a specific threshold from federal Title V permit requirements by limiting the facility's PTE.	SCAQMD	This Rule shall apply to any facility that would, if it did not comply with the limitations set forth in either paragraphs (d)(1) or (d)(2) of Rule 3008, have the PTE air contaminants equal to or in excess of the thresholds specified in Table 2, subdivision (b) of Rule 3001 – Applicability, or, for GHGs, 100,000 or more tpy of CO_2e. The HBEP will exceed the Title V thresholds listed in Rule 3001. As a result, the Project Owner submitted an application to modify the existing Title V permit.
SCAQMD Regulation XXXI, Permits (Acid Rain)	Incorporates by reference the provisions of 40 CFR 72 for purposes of implementing an acid rain program that meets the requirements of Title IV of the CAA.	SCAQMD with EPA Region IX Oversight	See 40 CFR 72 (Table 3-1) to review applicability and the compliance assessment.

Appendix A
Air Quality Impact Tables—Commissioning

Huntington Beach Energy Project
Appendix A, Table 1
Commissioning Stack Parameters
October 2015

Point Sources

Scenario	Source ID	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
GE 7FA.05, 10% Load	7FA01	409449	3723146	3.66	45.7	361	9.33	6.10
	7FA02	409474	3723182	3.66	45.7	361	9.33	6.10
	Aux Boiler	409438	3723236	3.66	24.4	432	21.2	0.91
GE 7FA.05, 40% Load	7FA01	409449	3723146	3.66	45.7	359	11.9	6.10
	7FA02	409474	3723182	3.66	45.7	359	11.9	6.10
	Aux Boiler	409438	3723236	3.66	24.4	432	21.2	0.91
GE 7FA.05, 80% Load	7FA01	409449	3723146	3.66	45.7	366	16.1	6.10
	7FA02	409474	3723182	3.66	45.7	366	16.1	6.10
	Aux Boiler	409438	3723236	3.66	24.4	432	21.2	0.91
GE LMS-100PB, 5% Load	7FA01	409449	3723146	3.66	45.7	350	12.2	6.10
	7FA02	409474	3723182	3.66	45.7	350	12.2	6.10
	LMS01	409149	3723193	3.66	24.4	728	10.0	4.11
	LMS02	409185	3723168	3.66	24.4	728	10.0	4.11
	Aux Boiler	409438	3723236	3.66	24.4	432	21.2	0.91
GE LMS-100PB, 75% Load	7FA01	409449	3723146	3.66	45.7	350	12.2	6.10
	7FA02	409474	3723182	3.66	45.7	350	12.2	6.10
	LMS01	409149	3723193	3.66	24.4	694	33.3	4.11
	LMS02	409185	3723168	3.66	24.4	694	33.3	4.11
	Aux Boiler	409438	3723236	3.66	24.4	432	21.2	0.91
GE LMS-100PB, Full Load	7FA01	409449	3723146	3.66	45.7	350	12.2	6.10
	7FA02	409474	3723182	3.66	45.7	350	12.2	6.10
	LMS01	409149	3723193	3.66	24.4	748	23.8	4.11
	LMS02	409185	3723168	3.66	24.4	748	23.8	4.11
	Aux Boiler	409438	3723236	3.66	24.4	432	21.2	0.91

Huntington Beach Energy Project
Appendix A, Table 2
Commissioning Emission Rates
October 2015

Short-Term Pollutant Commissioning Emissions

Scenario	Source ID	1-hour NO_2 (g/s)	1-hour NO_2 (lb/hr)	1-hour CO (g/s)	1-hour CO (lb/hr)	8-hour CO (g/s)	8-hour CO (lb/hr)
GE 7FA.05, 10% Load	7FA01	23.9	190	239	1,900	239	1,900
	7FA02	23.9	190	239	1,900	239	1,900
	Aux Boiler	0.027	0.21	0.18	1.42	0.14	1.09
GE 7FA.05, 40% Load	7FA01	8.60	68.3	Emission rates are captured by another modeled commissioning or operation scenario			
	7FA02	8.60	68.3				
	Aux Boiler	0.027	0.21				
GE 7FA.05, 80% Load	7FA01	7.94	63.0				
	7FA02	7.94	63.0				
	Aux Boiler	0.027	0.21				
GE LMS-100PB, 5% Load	7FA01	7.69	61.0	41.0	325	12.0	95.2
	7FA02	7.69	61.0	41.0	325	12.0	95.2
	LMS01	5.05	40.1	30.7	244	30.7	244
	LMS02	5.05	40.1	30.7	244	30.7	244
	Aux Boiler	0.027	0.21	0.18	1.42	0.14	1.09
GE LMS-100PB, 75% Load	7FA01	Emission rates are captured by another modeled commissioning or operation scenario		41.0	325	12.0	95.2
	7FA02			41.0	325	12.0	95.2
	LMS01			9.13	72.5	9.13	72.5
	LMS02			9.13	72.5	9.13	72.5
	Aux Boiler			0.18	1.42	0.14	1.09
GE LMS-100PB, Full Load	7FA01			41.0	325	12.0	95.2
	7FA02			41.0	325	12.0	95.2
	LMS01			11.3	90.0	11.3	90.0
	LMS02			11.3	90.0	11.3	90.0
	Aux Boiler			0.18	1.42	0.14	1.09

Annual Pollutant Commissioning Emissions

Scenario	Source ID	Annual NO_2 (g/s)	Annual NO_2 (lb/hr)	Annual PM_{10} (g/s)	Annual PM_{10} (lb/hr)	Annual $PM_{2.5}$ (g/s)	Annual $PM_{2.5}$ (lb/hr)
GE 7FA.05 [a]	7FA01	1.46	11.6	0.98	7.82	0.98	7.82
	7FA02	1.46	11.6	0.98	7.82	0.98	7.82
	Aux Boiler	0.017	0.14	0.010	0.082	0.010	0.082
GE LMS-100PB [b]	7FA01	1.02	8.12	0.86	6.79	0.86	6.79
	7FA02	1.02	8.12	0.86	6.79	0.86	6.79
	LMS01	0.32	2.53	0.15	1.20	0.15	1.20
	LMS02	0.32	2.53	0.15	1.20	0.15	1.20
	Aux Boiler	0.017	0.14	0.010	0.082	0.010	0.082

[a] GE 7FA.05 annual emissions include emissions from commissioning as well as annual operation.
[b] GE LMS-100PB annual emissions include emissions from commissioning as well as annual operation.

Huntington Beach Energy Project
Appendix A, Table 3
Commissioning Building Parameters
October 2015

GE 7FA.05 Commissioning Scenarios

Building Name	Number of Tiers	Tier Number	Base Elevation (m)	Tier Height (m)	Number of Corners	Corner 1 East (X) (m)	Corner 1 North (Y) (m)	Corner 2 East (X) (m)	Corner 2 North (Y) (m)	Corner 3 East (X) (m)	Corner 3 North (Y) (m)	Corner 4 East (X) (m)	Corner 4 North (Y) (m)	Corner 5 East (X) (m)	Corner 5 North (Y) (m)	Corner 6 East (X) (m)	Corner 6 North (Y) (m)	Corner 7 East (X) (m)	Corner 7 North (Y) (m)	Corner 8 East (X) (m)	Corner 8 North (Y) (m)	Corner 9 East (X) (m)	Corner 9 North (Y) (m)
'A RIN3'	1	-	3.66	21.6	9	409385	3723198	409377	3723187	409384	3723182	409387	3723182	409395	3723177	409401	3723185	409393	3723191	409391	3723194	409385	3723198
'A RIN4'	1	-	3.66	21.6	9	409426	3723221	409421	3723213	409412	3723218	409409	3723219	409402	3723223	409410	3723234	409416	3723230	409418	3723227	409426	3723221
'HRSG1'	1	-	3.66	25.6	5	409424	3723169	409447	3723152	409443	3723145	409418	3723162	409424	3723169								
'HRSG2'	1	-	3.66	25.6	5	409449	3723205	409473	3723188	409468	3723182	409444	3723198	409449	3723205								
'ACC'	1	-	3.66	33.5	5	409549	3723302	409551	3723173	409512	3723173	409510	3723301	409549	3723302								
'STG'	1	-	3.66	17.9	5	409482	3723251	409490	3723251	409490	3723235	409482	3723235	409482	3723251								
'WALL1'	1	-	3.66	15.2	9	409566	3723274	409567	3723158	409519	3723157	409437	3723109	409436	3723110	409519	3723158	409556	3723159	409565	3723274	409566	3723274
'WALL2'	1	-	3.66	6.10	7	409447	3723302	409427	3723301	409402	3723266	409402	3723265	409427	3723301	409447	3723301	409447	3723301				
'UNIT1L1'	2	1	3.66	23.2	4	409293	3723102	409312	3723128	409335	3723112	409317	3723086										
'UNIT1L2'	-	2	3.66	37.6	4	409301	3723114	409312	3723128	409335	3723112	409326	3723098										
'UNIT2L1'	2	1	3.66	23.2	4	409252	3723127	409272	3723153	409295	3723137	409277	3723111										
'UNIT2L2'	-	2	3.66	37.6	4	409261	3723139	409272	3723153	409295	3723137	409285	3723123										
'UNIT3L1'	2	1	3.66	23.2	4	409187	3723175	409206	3723202	409229	3723186	409211	3723159										
'UNIT3L2'	-	2	3.66	37.6	4	409195	3723187	409206	3723202	409229	3723186	409220	3723172										
'UNIT4L1'	2	1	3.66	23.2	4	409146	3723201	409165	3723228	409188	3723212	409170	3723185										
'UNIT4L2'	-	2	3.66	37.6	4	409154	3723213	409165	3723228	409188	3723212	409179	3723198										

Cylindical Building Name	Base Elevation (m)	Center East (X) (m)	Center North (Y) (m)	Tank Height (m)	Tank Diameter (m)
Stack12	3.66	409274	3723095	61.0	6.27
Stack34	3.66	409165	3723168	61.0	6.27

Huntington Beach Energy Project
Appendix A, Table 3
Commissioning Building Parameters
October 2015

GE LMS-100PB Commissioning Scenarios

Building Name	Number of Tiers	Tier Number	Base Elevation (m)	Tier Height (m)	Number of Corners	Corner 1 East (X) (m)	Corner 1 North (Y) (m)	Corner 2 East (X) (m)	Corner 2 North (Y) (m)	Corner 3 East (X) (m)	Corner 3 North (Y) (m)	Corner 4 East (X) (m)	Corner 4 North (Y) (m)	Corner 5 East (X) (m)	Corner 5 North (Y) (m)	Corner 6 East (X) (m)	Corner 6 North (Y) (m)	Corner 7 East (X) (m)	Corner 7 North (Y) (m)	Corner 8 East (X) (m)	Corner 8 North (Y) (m)	Corner 9 East (X) (m)	Corner 9 North (Y) (m)
'A RIN3'	1	-	3.66	21.6	9	409385	3723198	409377	3723187	409384	3723182	409387	3723182	409395	3723177	409401	3723185	409393	3723191	409391	3723194	409385	3723198
'A RIN4'	1	-	3.66	21.6	9	409426	3723221	409421	3723213	409412	3723218	409409	3723219	409402	3723223	409410	3723234	409416	3723230	409418	3723227	409426	3723221
'HRSG1'	1	-	3.66	25.6	5	409424	3723169	409447	3723152	409443	3723145	409418	3723162	409424	3723169								
'HRSG2'	1	-	3.66	25.6	5	409449	3723205	409473	3723188	409468	3723182	409444	3723198	409449	3723205								
'ACC'	1	-	3.66	33.5	5	409549	3723302	409551	3723173	409512	3723173	409510	3723301	409549	3723302								
'STG'	1	-	3.66	17.9	5	409482	3723251	409490	3723251	409490	3723235	409482	3723235	409482	3723251								
'WALL1'	1	-	3.66	15.2	9	409566	3723274	409567	3723158	409519	3723157	409437	3723109	409436	3723110	409519	3723158	409556	3723159	409565	3723274	409566	3723274
'WALL2'	1	-	3.66	6.10	7	409447	3723302	409427	3723301	409402	3723266	409402	3723265	409427	3723301	409447	3723301	409447	3723301				
'UNIT1L1'	2	1	3.66	23.2	4	409293	3723102	409312	3723128	409335	3723112	409317	3723086										
'UNIT1L2'	-	2	3.66	37.6	4	409301	3723114	409312	3723128	409335	3723112	409326	3723098										
'UNIT2L1'	2	1	3.66	23.2	4	409252	3723127	409272	3723153	409295	3723137	409277	3723111										
'UNIT2L2'	-	2	3.66	37.6	4	409261	3723139	409272	3723153	409295	3723137	409285	3723123										
'A RIN1'	1	-	3.66	15.6	5	409161	3723216	409148	3723225	409142	3723217	409155	3723207	409161	3723216								
'A RIN2'	1	-	3.66	15.6	5	409196	3723179	409202	3723187	409216	3723178	409210	3723169	409196	3723179								
'CTG1'	1	-	3.66	9.45	7	409160	3723207	409158	3723209	409151	3723201	409147	3723197	409153	3723193	409156	3723198	409160	3723207				
'CTG2'	1	-	3.66	9.45	7	409194	3723184	409197	3723182	409192	3723172	409190	3723168	409184	3723172	409187	3723176	409194	3723184				

Cylindical Building Name	Base Elevation (m)	Center East (X) (m)	Center North (Y) (m)	Tank Height (m)	Tank Diameter (m)
Stack12	3.66	409274	3723095	61.0	6.27

Huntington Beach Energy Project
Appendix A, Table 4
Commissioning Results
October 2015

Short-Term Pollutant Commissioning Results

Scenario	Year	NO_2 (µg/m³) [a] 1-hour	CO (µg/m³) 1-hour	CO (µg/m³) 8-hour
GE 7FA.05, 10% Load [b]	2010	136	2,498	1,784
	2011	166	3,097	1,654
	2012	158	2,878	1,737
	2013	179	3,377	1,793
	2014	143	2,654	1,576
GE 7FA.05, 40% Load	2010	62.7	-	-
	2011	59.5	-	-
	2012	61.4	-	-
	2013	62.0	-	-
	2014	66.5	-	-
GE 7FA.05, 80% Load	2010	40.6	-	-
	2011	33.6	-	-
	2012	42.8	-	-
	2013	29.1	-	-
	2014	42.3	-	-
GE LMS-100PB, 5% Load [c]	2010	75.6	504	117
	2011	75.9	506	117
	2012	79.0	527	115
	2013	77.3	515	125
	2014	79.1	527	125
GE LMS-100PB, 75% Load [c]	2010	-	503	95.3
	2011	-	506	91.0
	2012	-	526	98.8
	2013	-	514	96.2
	2014	-	526	89.5
GE LMS-100PB, Full Load [c]	2010	-	503	95.9
	2011	-	506	91.1
	2012	-	526	99.4
	2013	-	514	96.3
	2014	-	526	90.3

[a] The maximum 1-hour NO_2 concentrations include an ambient NO_2 ratio of 0.80 (EPA, 2011), unless otherwise noted.

[b] Commissioning impacts for the GE 7FA.05 10% load scenario are for a single turbine only. 1-hour NO_2 impacts were modeled using the Plume Volume Molar Ratio Method.

[c] The modeled impacts for the GE LMS-100PB commissioning scenarios include impacts from the auxiliary boiler and the GE 7FA.05 turbines operating in emissions scenario CC03.

Annual Pollutant Commissioning Results

Scenario	Year	NO_2 (µg/m³) [d] Annual	PM_{10} (µg/m³) Annual	$PM_{2.5}$ (µg/m³) Annual
GE 7FA.05 [e]	2010	0.59	0.52	0.52
	2011	0.60	0.54	0.54
	2012	0.66	0.59	0.59
	2013	0.66	0.59	0.59
	2014	0.66	0.58	0.58
GE LMS-100PB [f]	2010	0.43	0.47	0.47
	2011	0.44	0.48	0.48
	2012	0.48	0.53	0.53
	2013	0.49	0.53	0.53
	2014	0.48	0.53	0.53

[d] The maximum annual NO_2 concentrations include an ambient NO_2 ratio of 0.75 (EPA, 2005).

[e] Annual commissioning impacts are based on total emissions from commissioning and annual operation of 2 GE 7FA.05 turbines operating in exhaust scenario CC07 and the auxiliary boiler.
[f] Annual commissioning impacts are based on total emissions from operation of 2 GE 7FA.05 turbines operating in exhaust scenario CC07 and the auxiliary boiler, and commissioning and annual operation of 2 GE LMS-100PB turbines operating in exhaust scenario SC06 for NO_2 and SC07 for PM_{10} and $PM_{2.5}$.

Appendix B
Air Quality Impact Tables—Operations

Huntington Beach Energy Project
Appendix B, Table 1
Operational Stack Parameters
October 2015

Point Sources

Exhaust Scenario	Source ID	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
CC01	GE 7FA.05-01	409449	3723146	3.66	45.7	375	20.4	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	375	20.4	6.10
CC02	GE 7FA.05-01	409449	3723146	3.66	45.7	354	15.6	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	354	15.6	6.10
CC03	GE 7FA.05-01	409449	3723146	3.66	45.7	350	12.2	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	350	12.2	6.10
CC04	GE 7FA.05-01	409449	3723146	3.66	45.7	374	20.1	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	374	20.1	6.10
CC05	GE 7FA.05-01	409449	3723146	3.66	45.7	375	20.2	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	375	20.2	6.10
CC06	GE 7FA.05-01	409449	3723146	3.66	45.7	353	14.9	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	353	14.9	6.10
CC07	GE 7FA.05-01	409449	3723146	3.66	45.7	350	11.8	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	350	11.8	6.10
CC08	GE 7FA.05-01	409449	3723146	3.66	45.7	378	20.2	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	378	20.2	6.10
CC09	GE 7FA.05-01	409449	3723146	3.66	45.7	379	18.0	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	379	18.0	6.10
CC10	GE 7FA.05-01	409449	3723146	3.66	45.7	365	13.9	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	365	13.9	6.10
CC11	GE 7FA.05-01	409449	3723146	3.66	45.7	358	12.1	6.10
	GE 7FA.05-02	409474	3723182	3.66	45.7	358	12.1	6.10
SC01	GE LMS 100PB-01	409149	3723193	3.66	24.4	694	33.3	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	694	33.3	4.11
SC02	GE LMS 100PB-01	409149	3723193	3.66	24.4	709	28.7	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	709	28.7	4.11
SC03	GE LMS 100PB-01	409149	3723193	3.66	24.4	748	23.8	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	748	23.8	4.11
SC04	GE LMS 100PB-01	409149	3723193	3.66	24.4	697	33.1	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	697	33.1	4.11
SC05	GE LMS 100PB-01	409149	3723193	3.66	24.4	699	33.0	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	699	33.0	4.11
SC06	GE LMS 100PB-01	409149	3723193	3.66	24.4	709	28.4	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	709	28.4	4.11
SC07	GE LMS 100PB-01	409149	3723193	3.66	24.4	748	23.6	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	748	23.6	4.11
SC08	GE LMS 100PB-01	409149	3723193	3.66	24.4	726	29.4	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	726	29.4	4.11
SC09	GE LMS 100PB-01	409149	3723193	3.66	24.4	746	27.1	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	746	27.1	4.11
SC10	GE LMS 100PB-01	409149	3723193	3.66	24.4	769	23.7	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	769	23.7	4.11
SC11	GE LMS 100PB-01	409149	3723193	3.66	24.4	809	20.0	4.11
	GE LMS 100PB-02	409185	3723168	3.66	24.4	809	20.0	4.11
AB	Auxiliary Boiler	409438	3723236	3.66	24.4	432	21.2	0.91

Huntington Beach Energy Project
Appendix B, Table 2
Operational Emission Rates
October 2015

GE 7FA.05 Per Turbine Emission Rates

Exhaust	1-hour NO_2 [a]		1-hour CO [a]		8-hour CO [b]		1-hour SO_2		3-hour SO_2		24-hour SO_2		24-hour PM_{10}		24-hour $PM_{2.5}$		Annual NO_2 [c]		Annual PM_{10}		Annual $PM_{2.5}$	
Scenario	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)
CC01	7.69	61.0	41.0	325	12.3	97.9	0.61	4.86	0.61	4.86	0.61	4.86	1.13	9.00	1.13	9.00	-	-	-	-	-	-
CC02	7.69	61.0	41.0	325	12.2	96.4	0.48	3.84	0.48	3.84	0.48	3.84	1.13	9.00	1.13	9.00	-	-	-	-	-	-
CC03	7.69	61.0	41.0	325	12.0	95.2	0.37	2.95	0.37	2.95	0.37	2.95	1.13	9.00	1.13	9.00	-	-	-	-	-	-
CC04	7.18	57.0	36.2	287	11.0	87.5	0.61	4.81	0.61	4.81	0.61	4.81	1.13	9.00	1.13	9.00	1.63	13.0	0.86	6.79	0.86	6.79
CC05	7.18	57.0	36.2	287	11.0	87.4	0.60	4.78	0.60	4.78	0.60	4.78	1.13	9.00	1.13	9.00	1.61	12.8	0.86	6.79	0.86	6.79
CC06	7.18	57.0	36.2	287	10.8	85.9	0.47	3.72	0.47	3.72	0.47	3.72	1.13	9.00	1.13	9.00	1.30	10.3	0.86	6.79	0.86	6.79
CC07	7.18	57.0	36.2	287	10.7	84.5	0.35	2.79	0.35	2.79	0.35	2.79	1.13	9.00	1.13	9.00	1.02	8.12	0.86	6.79	0.86	6.79
CC08	6.68	53.0	27.7	220	8.80	69.9	0.58	4.60	0.58	4.60	0.58	4.60	1.13	9.00	1.13	9.00	-	-	-	-	-	-
CC09	6.68	53.0	27.7	220	8.72	69.2	0.52	4.16	0.52	4.16	0.52	4.16	1.13	9.00	1.13	9.00	-	-	-	-	-	-
CC10	6.68	53.0	27.7	220	8.57	68.0	0.42	3.33	0.42	3.33	0.42	3.33	1.13	9.00	1.13	9.00	-	-	-	-	-	-
CC11	6.68	53.0	27.7	220	8.46	67.1	0.34	2.67	0.34	2.67	0.34	2.67	1.13	9.00	1.13	9.00	-	-	-	-	-	-

GE LMS-100PB Per Turbine Emission Rates

Exhaust	1-hour NO_2 [d]		1-hour CO [e]		8-hour CO [d]		1-hour SO_2		3-hour SO_2		24-hour SO_2		24-hour PM_{10}		24-hour $PM_{2.5}$		Annual NO_2 [f]		Annual PM_{10}		Annual $PM_{2.5}$	
Scenario	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)
SC01	2.78	22.0	5.77	45.8	2.20	17.5	0.20	1.63	0.20	1.63	0.20	1.63	0.79	6.24	0.79	6.24	-	-	-	-	-	-
SC02	2.72	21.6	5.71	45.3	2.04	16.2	0.17	1.32	0.17	1.32	0.17	1.32	0.79	6.24	0.79	6.24	-	-	-	-	-	-
SC03	2.67	21.2	5.66	44.9	1.89	15.0	0.13	1.02	0.13	1.02	0.13	1.02	0.79	6.24	0.79	6.24	-	-	-	-	-	-
SC04	2.78	22.1	5.77	45.8	2.20	17.5	0.21	1.64	0.21	1.64	0.21	1.64	0.79	6.24	0.79	6.24	0.24	1.88	0.13	1.00	0.13	1.00
SC05	2.77	22.0	5.76	45.7	2.19	17.4	0.20	1.61	0.20	1.61	0.20	1.61	0.79	6.24	0.79	6.24	0.23	1.86	0.13	1.00	0.13	1.00
SC06	2.72	21.6	5.71	45.3	2.04	16.2	0.16	1.31	0.16	1.31	0.16	1.31	0.79	6.24	0.79	6.24	0.21	1.66	0.13	1.00	0.13	1.00
SC07	2.67	21.2	5.66	44.9	1.89	15.0	0.13	1.01	0.13	1.01	0.13	1.01	0.79	6.24	0.79	6.24	0.18	1.46	0.13	1.00	0.13	1.00
SC08	2.73	21.7	5.72	45.4	2.06	16.4	0.17	1.36	0.17	1.36	0.17	1.36	0.79	6.24	0.79	6.24	-	-	-	-	-	-
SC09	2.70	21.5	5.69	45.2	1.99	15.8	0.15	1.22	0.15	1.22	0.15	1.22	0.79	6.24	0.79	6.24	-	-	-	-	-	-
SC10	2.67	21.2	5.66	44.9	1.89	15.0	0.13	1.01	0.13	1.01	0.13	1.01	0.79	6.24	0.79	6.24	-	-	-	-	-	-
SC11	2.63	20.9	5.62	44.6	1.78	14.1	0.10	0.80	0.10	0.80	0.10	0.80	0.79	6.24	0.79	6.24	-	-	-	-	-	-

Auxiliary Boiler Emission Rates

Exhaust	1-hour NO_2		1-hour CO		8-hour CO		1-hour SO_2		3-hour SO_2		24-hour SO_2		24-hour PM_{10}		24-hour $PM_{2.5}$		Annual NO_2		Annual PM_{10}		Annual $PM_{2.5}$	
Scenario	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)
AB	0.027	0.21	0.18	1.42	0.14	1.09	0.0030	0.024	0.0030	0.024	0.0018	0.014	0.012	0.091	0.012	0.091	0.017	0.14	0.010	0.082	0.010	0.082

[a] Hourly CO and NO_2 emission rates for the GE 7FA.05s are based on cold startup events.

[b] 8-hour CO emission rates for the GE 7FA.05s are based on one cold start, one warm start, two shutdowns, and the balance of the period at steady-state operation.

[c] Annual emission rates for the GE 7FA.05s are based on 24 cold startups, 100 warm startups, 376 hot startups, 500 shutdowns, and 6,100 hours of steady-state operation.

[d] Hourly CO and NO_2 emission rates for the GE LMS-100PBs are based on one startup, one shutdown, and the balance of the hour at steady-state operation.

[e] 8-hour CO emission rates for the GE LMS-100PBs are based on two startups, two shutdowns, and the balance of the period at steady-state operation.

[f] Annual emission rates for the GE LMS-100PBs are based on 350 hot startups, 350 shutdowns, and 1,150 hours of steady-state operation.

Huntington Beach Energy Project
Appendix B, Table 3
Operational Building Parameters
October 2015

Building Name	Number of Tiers	Tier Number	Base Elevation (m)	Tier Height (m)	Number of Corners	Corner 1 East (X) (m)	Corner 1 North (Y) (m)	Corner 2 East (X) (m)	Corner 2 North (Y) (m)	Corner 3 East (X) (m)	Corner 3 North (Y) (m)	Corner 4 East (X) (m)	Corner 4 North (Y) (m)	Corner 5 East (X) (m)	Corner 5 North (Y) (m)	Corner 6 East (X) (m)	Corner 6 North (Y) (m)	Corner 7 East (X) (m)	Corner 7 North (Y) (m)	Corner 8 East (X) (m)	Corner 8 North (Y) (m)	Corner 9 East (X) (m)	Corner 9 North (Y) (m)
'AIRIN3'	1	-	3.66	21.6	9	409385	3723198	409377	3723187	409384	3723182	409387	3723182	409395	3723177	409401	3723185	409393	3723191	409391	3723194	409385	3723198
'AIRIN4'	1	-	3.66	21.6	9	409426	3723221	409421	3723213	409412	3723218	409409	3723219	409402	3723223	409410	3723234	409416	3723230	409418	3723227	409426	3723221
'HRSG1'	1	-	3.66	25.6	5	409424	3723169	409447	3723152	409443	3723145	409418	3723162	409424	3723169								
'HRSG2'	1	-	3.66	25.6	5	409449	3723205	409473	3723188	409468	3723182	409444	3723198	409449	3723205								
'ACC'	1	-	3.66	33.5	5	409549	3723302	409551	3723173	409512	3723173	409510	3723301	409549	3723302								
'STG'	1	-	3.66	17.9	5	409482	3723251	409490	3723251	409490	3723235	409482	3723235	409482	3723251								
'WALL1'	1	-	3.66	15.2	9	409566	3723274	409567	3723158	409519	3723157	409437	3723109	409436	3723110	409519	3723158	409566	3723159	409565	3723274	409566	3723274
'WALL2'	1	-	3.66	6.1	7	409447	3723302	409427	3723301	409402	3723266	409402	3723265	409427	3723301	409447	3723301	409447	3723301				
'AIRIN1'	1	-	3.66	15.6	5	409161	3723216	409148	3723225	409142	3723217	409155	3723207	409161	3723216								
'AIRIN2'	1	-	3.66	15.6	5	409196	3723179	409202	3723187	409216	3723178	409210	3723169	409196	3723179								
'CTG1'	1	-	3.66	9.4	7	409160	3723207	409158	3723209	409151	3723201	409147	3723197	409153	3723193	409156	3723198	409160	3723207				
'CTG2'	1	-	3.66	9.4	7	409194	3723184	409197	3723182	409192	3723172	409190	3723168	409184	3723172	409187	3723176	409194	3723184				

Huntington Beach Energy Project
Appendix B, Table 4
Operational Results – Load Analysis
October 2015

32°F Ambient Temperature Scenarios

Scenario Description [a]	Exhaust Scenario	Year	NO_2 (μg/m³) [b]		CO (μg/m³)		SO_2 (μg/m³)				PM_{10} (μg/m³)	$PM_{2.5}$ (μg/m³)
			1-hour	1-hour (federal) [c]	1-hour	8-hour	1-hour	1-hour (federal)	3-hour	24-hour	24-hour	24-hour
GE 7FA.05 Max. Load/ GE LMS-100PB Max. Load	CC01/SC01/AB	2010	43.2	102	288	25.8	4.28	2.08	2.92	0.53	1.07	0.71
		2011	22.2	105	148	24.0	2.20	1.79	1.57	0.42	0.86	0.70
		2012	43.0	102	287	25.5	4.26	1.73	1.68	0.63	1.23	0.73
		2013	21.5	102	143	25.5	2.13	1.77	1.59	0.47	0.97	0.73
		2014	41.5	103	276	26.2	4.11	2.13	2.21	0.53	1.06	0.77
GE 7FA.05 Max. Load/ GE LMS-100PB Ave. Load	CC01/SC02/AB	2010	43.2	102	288	25.8	4.28	2.08	2.92	0.53	1.07	0.72
		2011	22.2	105	148	24.0	2.20	1.79	1.57	0.42	0.88	0.73
		2012	43.0	103	287	25.5	4.26	1.73	1.68	0.63	1.25	0.74
		2013	21.5	103	143	25.5	2.13	1.77	1.59	0.47	0.98	0.75
		2014	41.5	103	276	26.2	4.11	2.13	2.21	0.53	1.08	0.79
GE 7FA.05 Max. Load/ GE LMS-100PB Min. Load	CC01/SC03/AB	2010	43.2	102	288	25.8	4.28	2.08	2.92	0.53	1.08	0.73
		2011	22.2	105	148	24.1	2.20	1.79	1.57	0.42	0.90	0.75
		2012	43.0	103	287	25.5	4.26	1.73	1.67	0.62	1.26	0.76
		2013	21.6	103	143	25.5	2.13	1.77	1.58	0.47	0.99	0.78
		2014	41.5	103	276	26.2	4.11	2.12	2.21	0.53	1.10	0.82
GE 7FA.05 Ave. Load/ GE LMS-100PB Max. Load	CC02/SC01/AB	2010	64.0	118	427	59.1	5.02	4.31	4.13	1.19	2.88	1.31
		2011	58.0	108	386	51.4	4.52	3.76	3.40	0.69	1.70	1.31
		2012	68.9	108	459	62.4	5.37	3.67	3.54	1.04	2.51	1.53
		2013	57.8	105	385	64.5	4.51	3.75	3.80	0.88	2.16	1.32
		2014	67.8	106	452	56.6	5.28	4.24	4.02	0.99	2.46	1.39
GE 7FA.05 Ave. Load/ GE LMS-100PB Ave. Load	CC02/SC02/AB	2010	64.0	118	427	59.1	5.02	4.31	4.13	1.19	2.88	1.32
		2011	58.0	108	387	51.4	4.52	3.76	3.40	0.69	1.71	1.32
		2012	68.9	108	459	62.5	5.37	3.67	3.54	1.04	2.52	1.53
		2013	57.8	105	385	64.5	4.51	3.75	3.80	0.88	2.16	1.33
		2014	67.8	106	452	56.6	5.28	4.24	4.02	0.99	2.47	1.40
GE 7FA.05 Ave. Load/ GE LMS-100PB Min. Load	CC02/SC03/AB	2010	64.0	118	427	59.1	5.01	4.31	4.13	1.19	2.88	1.32
		2011	58.0	109	387	51.5	4.52	3.76	3.40	0.69	1.72	1.33
		2012	68.9	108	459	62.5	5.37	3.67	3.54	1.04	2.53	1.54
		2013	57.8	105	385	64.5	4.51	3.75	3.80	0.88	2.16	1.33
		2014	67.8	106	452	56.6	5.28	4.24	4.02	0.99	2.48	1.40
GE 7FA.05 Min. Load/ GE LMS-100PB Max. Load	CC03/SC01/AB	2010	88.6	140	591	111	5.36	4.75	4.31	1.51	4.68	2.65
		2011	84.8	121	565	104	5.13	4.60	4.52	1.19	3.71	2.68
		2012	89.3	128	595	118	5.41	4.78	4.94	1.51	4.63	2.85
		2013	87.9	117	586	104	5.33	4.86	4.77	1.34	4.14	2.99
		2014	94.0	123	626	105	5.69	5.01	4.64	1.51	4.70	3.21
GE 7FA.05 Min. Load/ GE LMS-100PB Ave. Load	CC03/SC02/AB	2010	88.6	140	591	111	5.36	4.75	4.31	1.51	4.68	2.65
		2011	84.8	121	565	104	5.13	4.60	4.52	1.19	3.71	2.68
		2012	89.3	128	595	118	5.41	4.78	4.94	1.51	4.63	2.85
		2013	88.0	117	586	104	5.33	4.86	4.77	1.34	4.15	2.99
		2014	94.0	123	626	105	5.69	5.01	4.64	1.51	4.71	3.21
GE 7FA.05 Min. Load/ GE LMS-100PB Min. Load	CC03/SC03/AB	2010	88.6	140	591	111	5.36	4.75	4.31	1.51	4.68	2.65
		2011	84.8	121	565	104	5.13	4.60	4.52	1.19	3.71	2.69
		2012	89.3	128	595	118	5.41	4.78	4.94	1.51	4.64	2.86
		2013	88.0	117	586	104	5.32	4.86	4.77	1.34	4.15	3.00
		2014	94.0	123	627	105	5.69	5.01	4.64	1.51	4.72	3.22

Huntington Beach Energy Project
Appendix B, Table 4
Operational Results – Load Analysis
October 2015

65.8°F Ambient Temperature Scenarios

Scenario Description [a]	Exhaust Scenario	Year	NO_2 (µg/m³) [b]			CO (µg/m³)		SO_2 (µg/m³)				PM_{10} (µg/m³)		$PM_{2.5}$ (µg/m³)	
			1-hour	1-hour (federal) [c]	Annual	1-hour	8-hour	1-hour	1-hour (federal)	3-hour	24-hour	24-hour	Annual	24-hour	Annual
GE 7FA.05 Max. Load with Evap./ GE LMS-100PB Max. Load with Evap.	CC04/SC04/AB	2010	41.0	102	0.25	258	24.4	4.35	2.27	3.02	0.57	1.14	0.18	0.72	0.18
		2011	22.2	105	0.28	140	21.9	2.36	1.85	1.52	0.43	0.89	0.20	0.72	0.20
		2012	41.7	102	0.29	263	24.7	4.43	1.69	1.77	0.67	1.31	0.21	0.74	0.21
		2013	20.9	102	0.32	131	23.4	2.22	1.84	1.69	0.48	0.99	0.23	0.74	0.23
		2014	40.1	103	0.32	253	23.9	4.26	2.21	2.32	0.54	1.09	0.23	0.78	0.23
GE 7FA.05 Max. Load with Evap./ GE LMS-100PB Max. Load	CC04/SC05/AB	2010	41.0	102	0.25	258	24.4	4.35	2.27	3.02	0.57	1.14	0.18	0.72	0.18
		2011	22.2	105	0.28	140	21.9	2.36	1.85	1.52	0.43	0.89	0.20	0.72	0.20
		2012	41.7	102	0.29	263	24.7	4.43	1.69	1.77	0.67	1.32	0.21	0.74	0.21
		2013	20.9	102	0.32	131	23.4	2.22	1.84	1.69	0.48	0.99	0.23	0.74	0.23
		2014	40.1	103	0.32	253	23.9	4.26	2.21	2.32	0.54	1.09	0.23	0.78	0.23
GE 7FA.05 Max. Load with Evap./ GE LMS-100PB Ave. Load	CC04/SC06/AB	2010	41.0	102	0.25	258	24.4	4.35	2.27	3.02	0.57	1.14	0.18	0.74	0.18
		2011	22.2	105	0.28	140	22.0	2.36	1.85	1.52	0.43	0.91	0.20	0.74	0.20
		2012	41.7	102	0.29	263	24.7	4.43	1.69	1.77	0.67	1.33	0.21	0.76	0.21
		2013	20.9	102	0.32	132	23.4	2.22	1.84	1.69	0.48	1.00	0.23	0.76	0.23
		2014	40.1	103	0.32	253	23.9	4.26	2.21	2.32	0.54	1.10	0.23	0.81	0.23
GE 7FA.05 Max. Load with Evap./ GE LMS-100PB Min. Load	CC04/SC07/AB	2010	41.0	102	0.25	258	24.4	4.35	2.27	3.02	0.57	1.14	0.18	0.77	0.18
		2011	22.2	105	0.28	140	22.0	2.36	1.85	1.52	0.43	0.93	0.20	0.76	0.20
		2012	41.7	102	0.29	263	24.7	4.43	1.69	1.77	0.67	1.34	0.21	0.78	0.21
		2013	21.0	102	0.32	132	23.4	2.22	1.84	1.69	0.48	1.01	0.23	0.79	0.23
		2014	40.1	103	0.32	253	24.0	4.26	2.21	2.32	0.54	1.12	0.23	0.84	0.23
GE 7FA.05 Max. Load/ GE LMS-100PB Max. Load with Evap.	CC05/SC04/AB	2010	40.8	102	0.24	257	24.0	4.26	2.16	2.95	0.55	1.11	0.17	0.71	0.17
		2011	21.4	105	0.27	135	21.6	2.24	1.88	1.52	0.42	0.87	0.20	0.71	0.20
		2012	41.1	102	0.29	259	24.5	4.30	1.64	1.70	0.66	1.30	0.21	0.73	0.21
		2013	20.6	102	0.31	130	23.2	2.15	1.80	1.62	0.47	0.98	0.23	0.74	0.23
		2014	39.6	103	0.32	250	23.7	4.14	2.12	2.24	0.53	1.08	0.23	0.77	0.23
GE 7FA.05 Max. Load/ GE LMS-100PB Max. Load	CC05/SC05/AB	2010	40.8	102	0.24	257	24.0	4.26	2.16	2.95	0.55	1.11	0.17	0.71	0.17
		2011	21.4	105	0.27	135	21.6	2.24	1.88	1.51	0.42	0.87	0.20	0.71	0.20
		2012	41.1	102	0.28	259	24.5	4.30	1.64	1.70	0.66	1.30	0.21	0.73	0.21
		2013	20.6	102	0.31	130	23.2	2.15	1.80	1.62	0.47	0.98	0.23	0.74	0.23
		2014	39.6	103	0.31	250	23.7	4.14	2.12	2.23	0.53	1.08	0.23	0.77	0.23
GE 7FA.05 Max. Load/ GE LMS-100PB Ave. Load	CC05/SC06/AB	2010	40.8	102	0.24	257	24.0	4.26	2.16	2.95	0.55	1.11	0.17	0.73	0.17
		2011	21.4	105	0.27	135	21.7	2.24	1.88	1.51	0.42	0.88	0.20	0.73	0.20
		2012	41.1	102	0.29	259	24.5	4.30	1.64	1.70	0.65	1.32	0.21	0.75	0.21
		2013	20.6	102	0.31	130	23.2	2.15	1.79	1.62	0.47	0.99	0.23	0.76	0.23
		2014	39.6	103	0.31	250	23.7	4.14	2.12	2.23	0.53	1.10	0.23	0.80	0.23
GE 7FA.05 Max. Load/ GE LMS-100PB Min. Load	CC05/SC07/AB	2010	40.8	102	0.24	257	24.0	4.26	2.16	2.95	0.55	1.11	0.18	0.76	0.18
		2011	21.4	105	0.27	135	21.7	2.24	1.88	1.51	0.41	0.90	0.20	0.75	0.20
		2012	41.1	102	0.29	259	24.5	4.30	1.64	1.70	0.65	1.33	0.21	0.77	0.21
		2013	20.7	102	0.31	130	23.2	2.15	1.79	1.62	0.47	1.00	0.23	0.78	0.23
		2014	39.6	103	0.31	250	23.8	4.14	2.12	2.23	0.53	1.12	0.23	0.83	0.23

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65.8°F Ambient Temperature Scenarios

Scenario Description [a]	Exhaust Scenario	Year	NO_2 (µg/m³) [b]			CO (µg/m³)		SO_2 (µg/m³)				PM_{10} (µg/m³)		$PM_{2.5}$ (µg/m³)	
			1-hour	1-hour (federal) [c]	Annual	1-hour	8-hour	1-hour	1-hour (federal)	3-hour	24-hour	24-hour	Annual	24-hour	Annual
GE 7FA.05 Ave. Load/ GE LMS-100PB Max. Load with Evap.	CC06/SC04/AB	2010	64.7	121	0.36	409	62.2	5.32	4.60	4.30	1.31	3.22	0.31	1.51	0.31
		2011	58.6	108	0.39	370	53.7	4.80	4.12	3.79	0.80	2.00	0.34	1.43	0.34
		2012	67.5	108	0.41	426	69.0	5.52	4.07	3.93	1.10	2.73	0.36	1.63	0.36
		2013	55.7	105	0.44	351	66.0	4.56	4.15	4.22	0.99	2.47	0.38	1.53	0.38
		2014	67.1	107	0.43	423	64.6	5.49	4.59	4.29	1.24	3.10	0.38	1.51	0.38
GE 7FA.05 Ave. Load/ GE LMS-100PB Max. Load	CC06/SC05/AB	2010	64.7	121	0.36	409	62.2	5.32	4.60	4.30	1.31	1.22	0.31	1.51	0.31
		2011	58.6	108	0.39	370	53.7	4.80	4.12	3.79	0.80	2.00	0.34	1.43	0.34
		2012	67.5	108	0.41	426	69.0	5.52	4.07	3.93	1.10	2.73	0.36	1.63	0.36
		2013	55.7	105	0.43	351	66.0	4.56	4.15	4.22	0.99	2.47	0.38	1.53	0.38
		2014	67.1	107	0.43	423	64.6	5.49	4.59	4.29	1.24	3.10	0.38	1.51	0.38
GE 7FA.05 Ave. Load/ GE LMS-100PB Ave. Load	CC06/SC06/AB	2010	64.7	121	0.36	409	62.2	5.32	4.59	4.30	1.31	3.22	0.31	1.52	0.31
		2011	58.7	108	0.39	370	53.7	4.80	4.12	3.79	0.80	2.00	0.34	1.44	0.34
		2012	67.5	108	0.42	426	69.0	5.52	4.07	3.93	1.10	2.74	0.36	1.64	0.36
		2013	55.7	105	0.44	351	66.0	4.56	4.15	4.22	0.99	2.47	0.38	1.53	0.38
		2014	67.1	107	0.43	423	64.6	5.49	4.59	4.29	1.24	3.11	0.38	1.52	0.38
GE 7FA.05 Ave. Load/ GE LMS-100PB Min. Load	CC06/SC07/AB	2010	64.7	121	0.36	409	62.3	5.32	4.59	4.30	1.31	3.22	0.32	1.53	0.32
		2011	58.7	108	0.39	370	53.7	4.80	4.12	3.79	0.80	2.01	0.34	1.45	0.34
		2012	67.5	108	0.41	426	69.0	5.52	4.07	3.93	1.10	2.75	0.36	1.64	0.36
		2013	55.7	105	0.43	351	66.0	4.56	4.15	4.22	0.99	2.47	0.38	1.54	0.38
		2014	67.1	107	0.43	423	64.6	5.49	4.59	4.29	1.24	3.12	0.38	1.53	0.38
GE 7FA.05 Min. Load/ GE LMS-100PB Max. Load with Evap.	CC07/SC04/AB	2010	85.3	137	0.48	538	111	5.22	4.73	4.32	1.50	4.91	0.50	2.87	0.50
		2011	81.6	124	0.48	515	98.6	5.01	4.58	4.48	1.21	3.97	0.51	2.82	0.51
		2012	87.3	130	0.53	551	111	5.36	4.72	4.94	1.66	5.37	0.55	3.04	0.55
		2013	86.2	117	0.54	544	98.4	5.29	4.80	4.71	1.27	4.15	0.57	3.43	0.57
		2014	91.6	123	0.56	578	104	5.62	4.87	4.62	1.54	5.06	0.58	3.48	0.58
GE 7FA.05 Min. Load/ GE LMS-100PB Max. Load	CC07/SC05/AB	2010	85.3	137	0.48	538	111	5.22	4.73	4.32	1.50	4.91	0.50	2.87	0.50
		2011	81.6	124	0.48	515	98.6	5.00	4.58	4.48	1.21	3.97	0.51	2.82	0.51
		2012	87.3	130	0.53	551	111	5.36	4.72	4.94	1.66	5.37	0.55	3.04	0.55
		2013	86.2	117	0.54	544	98.4	5.29	4.80	4.70	1.27	4.15	0.57	3.43	0.57
		2014	91.6	123	0.56	578	104	5.62	4.87	4.62	1.54	5.06	0.58	3.48	0.58
GE 7FA.05 Min. Load/ GE LMS-100PB Ave. Load	CC07/SC06/AB	2010	85.3	137	0.48	538	111	5.22	4.73	4.32	1.50	4.91	0.50	2.87	0.50
		2011	81.6	124	0.48	515	98.6	5.00	4.58	4.48	1.21	3.97	0.51	2.82	0.51
		2012	87.3	130	0.53	551	111	5.36	4.72	4.94	1.66	5.38	0.55	3.04	0.55
		2013	86.2	117	0.54	544	98.4	5.29	4.80	4.70	1.27	4.15	0.57	3.43	0.57
		2014	91.6	123	0.56	578	104	5.62	4.87	4.62	1.54	5.07	0.58	3.48	0.58
GE 7FA.05 Min. Load/ GE LMS-100PB Min. Load	CC07/SC07/AB	2010	85.3	137	0.48	538	111	5.22	4.73	4.32	1.50	4.91	0.50	2.87	0.50
		2011	81.6	124	0.48	515	98.6	5.00	4.58	4.48	1.21	3.97	0.51	2.82	0.51
		2012	87.4	130	0.53	551	111	5.36	4.72	4.94	1.66	5.38	0.56	3.05	0.56
		2013	86.2	117	0.54	544	98.4	5.29	4.80	4.70	1.27	4.15	0.57	3.44	0.57
		2014	91.7	123	0.56	578	104	5.62	4.87	4.62	1.54	5.07	0.59	3.48	0.59

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Scenario Description [a]	Exhaust Scenario	Year	NO_2 (µg/m³) [b] 1-hour	NO_2 (µg/m³) [b] 1-hour (federal) [c]	CO (µg/m³) 1-hour	CO (µg/m³) 8-hour	SO_2 (µg/m³) 1-hour	SO_2 (µg/m³) 1-hour (federal)	SO_2 (µg/m³) 3-hour	SO_2 (µg/m³) 24-hour	PM_{10} (µg/m³) 24-hour	$PM_{2.5}$ (µg/m³) 24-hour
GE 7FA.05 Max. Load with Evap./ GE LMS-100PB Max. Load with Evap.	CC08/SC08/AB	2010	37.8	102	196	19.3	4.11	2.01	2.80	0.51	1.08	0.71
		2011	19.3	104	100	17.5	2.09	1.73	1.43	0.40	0.87	0.71
		2012	37.4	102	194	18.6	4.06	1.64	1.59	0.60	1.24	0.73
		2013	18.7	102	96.4	18.5	2.02	1.63	1.50	0.45	0.97	0.74
		2014	36.3	102	188	19.1	3.94	2.01	2.11	0.50	1.06	0.78
GE 7FA.05 Max. Load with Evap./ GE LMS-100PB Max. Load	CC08/SC09/AB	2010	37.8	102	196	19.3	4.11	2.01	2.80	0.51	1.08	0.73
		2011	19.3	104	100	17.6	2.09	1.73	1.43	0.40	0.87	0.72
		2012	37.4	102	194	18.6	4.06	1.64	1.59	0.60	1.25	0.74
		2013	18.7	102	96.4	18.5	2.01	1.63	1.50	0.44	0.98	0.75
		2014	36.3	102	188	19.2	3.94	2.01	2.11	0.49	1.07	0.79
GE 7FA.05 Max. Load with Evap./ GE LMS-100PB Ave. Load	CC08/SC10/AB	2010	37.8	102	196	19.3	4.11	2.01	2.80	0.51	1.08	0.74
		2011	19.3	104	100	17.6	2.09	1.73	1.43	0.40	0.89	0.74
		2012	37.4	102	194	18.6	4.06	1.64	1.59	0.60	1.26	0.76
		2013	18.7	102	96.5	18.5	2.01	1.63	1.50	0.44	0.99	0.77
		2014	36.3	102	188	19.2	3.94	2.01	2.11	0.49	1.08	0.81
GE 7FA.05 Max. Load with Evap./ GE LMS-100PB Min. Load	CC08/SC11/AB	2010	37.8	102	196	19.3	4.11	2.01	2.80	0.51	1.08	0.75
		2011	19.3	105	100	17.6	2.09	1.73	1.43	0.40	0.90	0.77
		2012	37.4	102	194	18.6	4.06	1.64	1.59	0.59	1.28	0.78
		2013	18.7	102	96.5	18.5	2.01	1.63	1.49	0.44	1.00	0.79
		2014	36.3	102	188	19.2	3.94	2.01	2.11	0.49	1.10	0.84
GE 7FA.05 Max. Load/ GE LMS-100PB Max. Load with Evap.	CC09/SC08/AB	2010	44.5	102	231	25.9	4.33	2.67	3.20	0.69	1.57	0.82
		2011	29.0	105	150	19.7	2.82	1.95	1.51	0.41	0.99	0.81
		2012	45.7	102	237	22.8	4.44	2.05	1.96	0.66	1.50	0.90
		2013	23.6	102	122	25.3	2.30	1.95	1.96	0.54	1.26	0.81
		2014	44.3	103	230	24.1	4.31	2.50	2.68	0.58	1.33	0.85
GE 7FA.05 Max. Load/ GE LMS-100PB Max. Load	CC09/SC09/AB	2010	44.5	102	231	25.9	4.33	2.67	3.20	0.69	1.57	0.82
		2011	29.0	105	150	19.7	2.82	1.95	1.51	0.41	0.99	0.82
		2012	45.7	102	237	22.8	4.44	2.05	1.96	0.66	1.50	0.91
		2013	23.6	102	122	25.3	2.30	1.95	1.96	0.54	1.27	0.82
		2014	44.3	103	230	24.1	4.31	2.50	2.68	0.57	1.34	0.86
GE 7FA.05 Max. Load/ GE LMS-100PB Ave. Load	CC09/SC10/AB	2010	44.5	102	231	25.9	4.33	2.67	3.20	0.69	1.57	0.84
		2011	29.0	105	150	19.7	2.82	1.95	1.51	0.41	1.00	0.83
		2012	45.7	102	237	22.8	4.44	2.05	1.96	0.66	1.51	0.91
		2013	23.6	102	122	25.3	2.30	1.95	1.96	0.54	1.27	0.83
		2014	44.3	103	230	24.1	4.31	2.50	2.68	0.57	1.35	0.88
GE 7FA.05 Max. Load/ GE LMS-100PB Min. Load	CC09/SC11/AB	2010	44.5	102	231	25.9	4.33	2.67	3.20	0.69	1.57	0.86
		2011	29.0	105	150	19.8	2.82	1.95	1.51	0.41	1.02	0.84
		2012	45.7	102	237	22.9	4.44	2.05	1.96	0.66	1.52	0.92
		2013	23.6	102	122	25.3	2.30	1.94	1.96	0.54	1.28	0.85
		2014	44.3	103	230	24.2	4.31	2.50	2.68	0.57	1.36	0.90

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			NO_2 (µg/m³) [b]		CO (µg/m³)		SO_2 (µg/m³)				PM_{10} (µg/m³)	$PM_{2.5}$ (µg/m³)
Scenario Description [a]	Exhaust Scenario	Year	1-hour	1-hour (federal) [c]	1-hour	8-hour	1-hour	1-hour (federal)	3-hour	24-hour	24-hour	24-hour
GE 7FA.05 Ave. Load/ GE LMS-100PB Max. Load with Evap.	CC10/SC08/AB	2010	61.8	121	321	49.5	4.87	4.25	3.98	1.22	3.35	1.48
		2011	56.7	107	294	43.7	4.45	3.84	3.46	0.73	2.03	1.42
		2012	64.6	107	335	55.1	5.07	3.68	3.59	0.98	2.73	1.59
		2013	51.9	104	269	53.2	4.08	3.81	3.81	0.90	2.50	1.52
		2014	63.8	106	331	52.8	5.01	4.17	3.92	1.13	3.16	1.46
GE 7FA.05 Ave. Load/ GE LMS-100PB Max. Load	CC10/SC09/AB	2010	61.8	121	321	49.5	4.87	4.25	3.98	1.22	3.35	1.48
		2011	56.7	107	294	43.7	4.45	3.84	3.46	0.73	2.03	1.42
		2012	64.6	107	335	55.1	5.07	3.68	3.59	0.98	2.73	1.60
		2013	51.9	104	269	53.2	4.08	3.81	3.81	0.90	2.50	1.52
		2014	63.8	106	331	52.8	5.01	4.17	3.92	1.13	3.16	1.46
GE 7FA.05 Ave. Load/ GE LMS-100PB Ave. Load	CC10/SC10/AB	2010	61.8	121	321	49.6	4.87	4.25	3.98	1.22	3.35	1.49
		2011	56.7	107	294	43.8	4.45	3.84	3.46	0.73	2.04	1.43
		2012	64.6	107	335	55.1	5.07	3.67	3.59	0.98	2.73	1.61
		2013	51.9	104	269	53.2	4.08	3.81	3.81	0.90	2.50	1.52
		2014	63.8	106	331	52.9	5.01	4.17	3.92	1.13	3.17	1.46
GE 7FA.05 Ave. Load/ GE LMS-100PB Min. Load	CC10/SC11/AB	2010	61.8	121	321	49.6	4.87	4.25	3.98	1.22	3.35	1.50
		2011	56.7	107	294	43.8	4.45	3.84	3.46	0.73	2.05	1.44
		2012	64.6	107	335	55.1	5.07	3.67	3.59	0.98	2.74	1.62
		2013	51.9	104	269	53.2	4.08	3.81	3.81	0.90	2.50	1.53
		2014	63.8	106	331	52.9	5.01	4.17	3.92	1.13	3.18	1.46
GE 7FA.05 Min. Load/ GE LMS-100PB Max. Load with Evap.	CC11/SC08/AB	2010	74.5	127	387	75.1	4.76	4.20	3.79	1.33	4.47	2.38
		2011	70.2	117	365	64.0	4.50	3.99	3.93	0.95	3.20	2.43
		2012	72.7	116	377	77.6	4.65	4.11	4.20	1.23	4.09	2.53
		2013	71.5	109	372	69.2	4.58	4.12	4.18	1.12	3.76	2.67
		2014	77.5	111	403	70.2	4.97	4.31	3.98	1.25	4.21	2.78
GE 7FA.05 Min. Load/ GE LMS-100PB Max. Load	CC11/SC09/AB	2010	74.5	127	387	75.1	4.76	4.20	3.79	1.33	4.47	2.38
		2011	70.2	117	365	64.1	4.50	3.99	3.93	0.94	3.20	2.43
		2012	72.7	116	377	77.6	4.65	4.11	4.20	1.23	4.10	2.53
		2013	71.5	109	372	69.2	4.58	4.12	4.18	1.12	3.76	2.68
		2014	77.5	111	403	70.2	4.96	4.31	3.98	1.25	4.21	2.78
GE 7FA.05 Min. Load/ GE LMS-100PB Ave. Load	CC11/SC10/AB	2010	74.5	127	387	75.1	4.76	4.20	3.79	1.33	4.47	2.39
		2011	70.2	117	365	64.1	4.50	3.99	3.93	0.94	3.21	2.43
		2012	72.7	116	377	77.6	4.64	4.11	4.20	1.23	4.10	2.53
		2013	71.5	109	372	69.2	4.58	4.12	4.18	1.12	3.76	2.68
		2014	77.5	111	403	70.2	4.96	4.31	3.98	1.25	4.22	2.78
GE 7FA.05 Min. Load/ GE LMS-100PB Min. Load	CC11/SC11/AB	2010	74.5	127	387	75.1	4.76	4.20	3.79	1.33	4.47	2.39
		2011	70.2	117	365	64.1	4.50	3.99	3.93	0.94	3.22	2.43
		2012	72.7	116	377	77.7	4.64	4.11	4.20	1.23	4.10	2.54
		2013	71.5	109	372	69.2	4.58	4.12	4.18	1.12	3.76	2.68
		2014	77.6	111	403	70.2	4.96	4.31	3.98	1.25	4.22	2.79

[a] All modeled scenarios include two GE 7FA.05 turbines, two GE LMS-100PB turbines, and the auxiliary boiler.
[b] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 (EPA, 2011) and 0.75 (EPA, 2005), respectively.
[c] The total predicted concentration for the federal 1-hour NO_2 standard is the high-8th-high modeled concentration paired with 98th percentile seasonal hour-of-day background concentrations for 2010 through 2012.

Huntington Beach Energy Project
Appendix B, Table 5
Operational Results – SCAQMD Rule 2005
October 2015

GE 7FA.05 Unit 1

Year	1-hour Concentration (μg/m³) [a, b]	1-hour Federal Concentration (μg/m³) [a, c]	Annual Concentration (μg/m³) [a, d]
2010	38.9	40.0	0.17
2011	34.5	35.5	0.17
2012	38.9	41.0	0.19
2013	42.2	43.8	0.19
2014	43.1	39.4	0.19

GE 7FA.05 Unit 2

Year	1-hour Concentration (μg/m³) [a, b]	1-hour Federal Concentration (μg/m³) [a, c]	Annual Concentration (μg/m³) [a, d]
2010	60.3	52.0	0.23
2011	53.3	49.1	0.24
2012	52.7	51.2	0.27
2013	58.5	62.0	0.26
2014	55.0	53.6	0.27

GE LMS-100PB Unit 1

Year	1-hour Concentration (μg/m³) [a, b]	1-hour Federal Concentration (μg/m³) [a, c]	Annual Concentration (μg/m³) [a, d]
2010	2.94	2.96	0.011
2011	3.03	3.05	0.013
2012	3.09	3.11	0.013
2013	3.12	3.14	0.015
2014	2.60	2.61	0.015

GE LMS-100PB Unit 2

Year	1-hour Concentration (μg/m³) [a, b]	1-hour Federal Concentration (μg/m³) [a, c]	Annual Concentration (μg/m³) [a, d]
2010	2.95	2.97	0.011
2011	3.01	3.03	0.013
2012	3.12	3.14	0.013
2013	3.07	3.10	0.015
2014	2.88	2.91	0.015

Auxiliary Boiler

Year	1-hour Concentration (μg/m³) [a]	1-hour Federal Concentration (μg/m³) [a]	Annual Concentration (μg/m³) [a]
2010	1.36	1.36	0.13
2011	1.27	1.27	0.13
2012	1.33	1.33	0.14
2013	1.16	1.16	0.13
2014	1.19	1.19	0.13

[a] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 (EPA, 2011) and 0.75 (EPA, 2005), respectively.
[b] The modeled impact for the 1-hour NO_2 CAAQS for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC03 and SC03, respectively.
[c] The modeled impact for the 1-hour NO_2 NAAQS for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC07 and SC07, respectively.
[d] The modeled impact for the Annual NO_2 AAQS for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC07 and SC06, respectively.

Huntington Beach Energy Project
Appendix B, Table 6
Operational Results – Class II SIL and Increment
October 2015

	NO_2 ($\mu g/m^3$) [a]		CO ($\mu g/m^3$)		PM_{10} ($\mu g/m^3$)	
Year	1-hour [b]	Annual [c]	1-hour [b]	8-hour [b]	24-hour [d]	Annual [e]
2010	88.6	0.48	591	111	4.65	0.50
2011	84.8	0.48	565	104	3.62	0.51
2012	89.3	0.53	595	118	4.93	0.56
2013	88.0	0.54	586	104	3.81	0.57
2014	94.0	0.56	627	105	4.76	0.59

[a] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 ratios of 0.80 (EPA, 2011) and 0.75 (EPA, 2005), respectively.

[b] The modeled impact for the 1-hour NO_2, 1-hour CO, and 8-hour CO Class II SIL and Increment for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC03 and SC03, respectively.
[b] The modeled impact for the Annual NO_2 Class II SIL and Increment for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC07 and SC06, respectively.
[d] The 24-hour PM_{10} concentration is based on the GE LMS-100PB turbines operating in exhaust scenario SC07 and both GE 7FA.05 turbines operating 20 hours per day in exhaust scenario CC07 and 4 hours per day in exhaust scenario CC06.
[e] The modeled impact for the Annual PM_{10} Class II SIL and Increment for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC07 and SC06, respectively.

Huntington Beach Energy Project
Appendix B, Table 7
Competing Source Stack Parameters
October 2015

Point Sources

Facility	Source ID	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
HBEP	7FA01	409449	3723146	3.66	45.7	350	11.8	6.10
	7FA02	409474	3723182	3.66	45.7	350	11.8	6.10
	LMS01	409149	3723193	3.66	24.4	748	23.6	4.11
	LMS02	409185	3723168	3.66	24.4	748	23.6	4.11
	AUXBOILER	409438	3723236	3.66	24.4	432	21.2	0.91
Huntington Beach Generating Station (HBGS)	BOILER12	409274	3723095	3.66	61.0	367	7.90	6.27
Orange County Sanitation - Fountain Valley (OCSFV)	1730101	412962	3728359	8.00	7.41	1,089	1.37	2.23
	1730102	412914	3728328	7.70	7.62	475	7.03	0.55
	1730103	412935	3728401	8.00	18.9	533	17.9	0.76
	1730104	412942	3728391	8.00	18.9	533	17.9	0.76
	1730105	412939	3728396	8.00	18.9	533	17.9	0.76
Orange County Sanitation - Huntington Beach (OCSHB)	2911001	411071	3722313	1.60	7.62	475	7.44	0.53
	2911002	411096	3722214	1.60	7.41	1089	1.37	0.68
	2911003	411240	3722455	1.60	18.0	589	22.9	0.76
	2911004	411248	3722455	1.60	18.0	589	22.9	0.76
	2911005	411255	3722455	1.60	18.0	589	22.9	0.76
	2911006	411263	3722455	1.60	18.0	589	22.9	0.76
	2911007	411270	3722455	1.60	18.0	589	22.9	0.76
Beta Offshore (Beta)	16607301	395222	3716431	0	18.3	661	31.1	0.30
	16607302	395222	3716431	0	18.3	641	30.0	0.30
	16607303	395222	3716431	0	18.3	585	24.2	0.30
	16607304	394082	3717932	0	18.3	663	28.7	0.30
	16607305	394082	3717932	0	18.3	684	34.7	0.30
	16607306	394082	3717932	0	18.3	583	21.1	0.30
	16607307	395265	3716554	0	18.3	671	39.4	0.61
	16607308	395265	3716554	0	18.3	671	38.1	0.61
	16607309	395265	3716554	0	18.3	677	37.5	0.61
	16607310	395265	3716554	0	18.3	671	81.2	0.76
	16607311	395265	3716554	0	18.3	669	81.1	0.76
	16607312	395265	3716554	0	18.3	668	81.4	0.76
	16607313	395265	3716554	0	22.9	464	8.35	0.51

Volume Sources

Facility	Source ID	Base Elevation (m)	Release Height (m)	Initial Horizontal Dimension (m)	Initial Vertical Dimension (m)
Shipping Lanes (525 sources)	734601-774425	0	0.0	186	23.3

Competing source data provided by SCAQMD.

Huntington Beach Energy Project
Appendix B, Table 8
Competing Source Emission Rates
October 2015

Emission Rates for PSD 1-hour NO_2 Competing Source Modeling

		1-hour NO_2	
Facility	Source ID	(g/s)	(lb/hr)
HBEP	7FA01	7.18	57.0
	7FA02	7.18	57.0
	LMS01	2.67	21.2
	LMS02	2.67	21.2
	AUXBOILER	0.03	0.21
HBGS	BOILER12	4.32	34.3
OCSFV	1730101	0.65	5.17
	1730102	0.01	0.08
	1730103	0.98	7.78
	1730104	0.98	7.78
	1730105	0.98	7.78
OCSHB	2911001	0.08	0.60
	2911002	0.11	0.87
	2911003	0.87	6.90
	2911004	0.87	6.90
	2911005	0.87	6.90
	2911006	0.87	6.90
	2911007	0.87	6.90
Beta	16607301	1.90	15.1
	16607302	1.90	15.1
	16607303	1.90	15.1
	16607304	1.90	15.1
	16607305	1.90	15.1
	16607306	1.90	15.1
	16607307	0.37	2.94
	16607308	0.31	2.46
	16607309	0.35	2.78
	16607310	2.52	20.0
	16607311	2.48	19.7
	16607312	2.48	19.7
	16607313	10.3	81.6
Shipping Lanes (Total for 525 sources)	734601-774425	25.5	202

Competing source data provided by SCAQMD.

Huntington Beach Energy Project
Appendix B, Table 9
Competing Source Results
October 2015

1-hour NO_2 Concentrations ($\mu g/m^3$) [a, b]

Year	2010	2011	2012	2013	2014
All	140	148	150	146	146
HBEP	75.2	70.6	72.9	74.1	76.0
HBGS	5.15	5.08	5.32	5.12	4.73
OCSFV	8.99	8.98	9.02	8.92	9.06
OCSHB	56.2	54.0	54.1	54.1	53.7
BETA	67.6	68.6	67.0	67.1	66.1
SHIPS	24.3	25.4	25.4	22.8	25.4

[a] The total predicted concentration for the federal 1-hour NO_2 standard is the high-8th-high modeled concentration paired with 98th percentile seasonal hour-of-day background concentrations for 2010 through 2012.

[b] The modeled impact for the 1-hour NO_2 competing source assessment for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC03 and SC03, respectively.

Huntington Beach Energy Project
Appendix B, Table 10
Operational Results – Class I SIL and Increment
October 2015

Annual NO_2 Concentrations ($\mu g/m^3$) at 50 km Receptor Ring [a, b]

Year	2010	2011	2012	2013	2014
All	0.0062	0.0061	0.0062	0.0058	0.0054
GE 7FA.05 Unit 1	0.0026	0.0026	0.0026	0.0025	0.0023
GE 7FA.05 Unit 2	0.0026	0.0026	0.0026	0.0025	0.0023
GE LMS-100PB Unit 1	0.0004	0.0004	0.0004	0.0004	0.0004
GE LMS-100PB Unit 2	0.0004	0.0004	0.0004	0.0004	0.0004
Auxiliary Boiler	0.0001	0.0001	0.0001	0.0001	0.0001

24-hour PM_{10} Concentrations ($\mu g/m^3$) at 50 km Receptor Ring [c]

Year	2010	2011	2012	2013	2014
All	0.055	0.054	0.055	0.053	0.046
GE 7FA.05 Unit 1	0.019	0.020	0.019	0.018	0.016
GE 7FA.05 Unit 2	0.019	0.020	0.019	0.018	0.016
GE LMS-100PB Unit 1	0.0098	0.0096	0.011	0.0088	0.0089
GE LMS-100PB Unit 2	0.0097	0.0096	0.010	0.0088	0.0089
Auxiliary Boiler	0.0003	0.0004	0.0003	0.0004	0.0003

Annual PM_{10} Concentrations ($\mu g/m^3$) at 50 km Receptor Ring [c]

Year	2010	2011	2012	2013	2014
All	0.0067	0.0066	0.0067	0.0063	0.0059
GE 7FA.05 Unit 1	0.0030	0.0029	0.0029	0.0028	0.0026
GE 7FA.05 Unit 2	0.0030	0.0029	0.0029	0.0028	0.0026
GE LMS-100PB Unit 1	0.0004	0.0004	0.0004	0.0004	0.0003
GE LMS-100PB Unit 2	0.0004	0.0004	0.0004	0.0004	0.0003
Auxiliary Boiler	5.0E-05	5.0E-05	5.0E-05	5.0E-05	4.0E-05

[a] The maximum annual NO_2 concentrations include an ambient NO_2 ratio of 0.75 (EPA, 2005).

[b] The modeled impact for the Annual NO_2 Class I SIL and Increment for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC07 and SC06, respectively.

[c] The modeled impact for the 24-hour and annual PM_{10} Class I SIL and Increment for the GE 7FA.05 and GE LMS-100PB units are based on exhaust scenarios CC07 and SC07, respectively.

Attachment 3
Combined-cycle Turbine Startup Emissions

Combined Cycle: Summary of Start-Up and Shutdown Emissions Estimates
October 2015
Cold Start

20 deg F									
Pollutant	**Startup**	**Duration (min)**	**Catalyst Inlet (lb/hr)**	**Inlet Over Duration (lbs)**	**Design Reduction (%)**	**Transient Reduction (%)**	**Net Reduction (%)**	**Total Outlet (lbs)**	**Emissions per Event (lbs)**
NO_x	T0-T10	10	64	11	80%	0%	0%	11	
NO_x	T10-T20	10	95	16	80%	0%	0%	16	
NO_x	T20-T30	10	75	13	80%	0%	0%	13	
NO_x	T30-T40	10	75	13	80%	70%	56%	6	
NO_x	T40-T50	10	75	13	80%	85%	68%	4	
NO_x	T50-T60	10	75	13	80%	100%	80%	3	
NO_x	**Total Startup**							51	61
CO	T0-T10	10	738	123	80%	30%	24%	93	
CO	T10-T20	10	1351	225	80%	35%	28%	162	
CO	T20-T30	10	59	10	80%	50%	40%	6	
CO	T30-T40	10	59	10	80%	75%	60%	4	
CO	T40-T50	10	59	10	80%	90%	72%	3	
CO	T50-T60	10	59	10	80%	100%	80%	2	
CO	**Total Startup**							270	325
VOC	T0-T10	10	84	14	50%	30%	15%	12	
VOC	T10-T20	10	127	21	50%	35%	18%	17	
VOC	T20-T30	10	5	0.8	50%	50%	25%	0.6	
VOC	T30-T40	10	5	0.8	50%	75%	38%	0.5	
VOC	T40-T50	10	5	0.8	50%	90%	45%	0.4	
VOC	T50-T60	10	5	0.8	50%	100%	50%	0.4	
VOC	**Total Startup**							31	36

59 deg F									
Pollutant	**Startup**	**Duration (min)**	**Catalyst Inlet (lb/hr)**	**Inlet Over Duration (lbs)**	**Design Reduction (%)**	**Transient Reduction (%)**	**Net Reduction (%)**	**Total Outlet (lbs)**	**Emissions per Event (lbs)**
NO_x	T0-T10	10	63	11	80%	0%	0%	11	
NO_x	T10-T20	10	86	14	80%	0%	0%	14	
NO_x	T20-T30	10	68	11	80%	0%	0%	11	
NO_x	T30-T40	10	68	11	80%	70%	56%	5	
NO_x	T40-T50	10	68	11	80%	85%	68%	4	
NO_x	T50-T60	10	68	11	80%	100%	80%	2	
NO_x	**Total Startup**							47	57
CO	T0-T10	10	646	108	80%	30%	24%	82	
CO	T10-T20	10	1183	197	80%	35%	28%	142	
CO	T20-T30	10	52	9	80%	50%	40%	5	
CO	T30-T40	10	52	9	80%	75%	60%	3	
CO	T40-T50	10	52	9	80%	90%	72%	2	
CO	T50-T60	10	52	9	80%	100%	80%	2	
CO	**Total Startup**							237	287
VOC	T0-T10	10	79	13	50%	30%	15%	11	
VOC	T10-T20	10	118	20	50%	35%	18%	16	
VOC	T20-T30	10	5	0.8	50%	50%	25%	0.6	
VOC	T30-T40	10	5	0.8	50%	75%	38%	0.5	
VOC	T40-T50	10	5	0.8	50%	90%	45%	0.5	
VOC	T50-T60	10	5	0.8	50%	100%	50%	0.4	
VOC	**Total Startup**							29	36

100 deg F									
Pollutant	**Startup**	**Duration (min)**	**Catalyst Inlet (lb/hr)**	**Inlet Over Duration (lbs)**	**Design Reduction (%)**	**Transient Reduction (%)**	**Net Reduction (%)**	**Total Outlet (lbs)**	**Emissions per Event (lbs)**
NO_x	T0-T10	10	62.4	10.4	80%	0%	0%	10	
NO_x	T10-T20	10	75.0	12.5	80%	0%	0%	13	
NO_x	T20-T30	10	62.0	10.3	80%	0%	0%	10	
NO_x	T30-T40	10	62.0	10.3	80%	70%	56%	5	
NO_x	T40-T50	10	62.0	10.3	80%	85%	68%	3	
NO_x	T50-T60	10	62.0	10.3	80%	100%	80%	2	
NO_x	**Total Startup**							43	53
CO	T0-T10	10	500.7	83.5	80%	30%	24%	63	
CO	T10-T20	10	916.8	152.8	80%	35%	28%	110	
CO	T20-T30	10	40.0	6.7	80%	50%	40%	4	
CO	T30-T40	10	40.0	6.7	80%	75%	60%	3	
CO	T40-T50	10	40.0	6.7	80%	90%	72%	2	
CO	T50-T60	10	40.0	6.7	80%	100%	80%	1	
CO	**Total Startup**							183	220
VOC	T0-T10	10	56.6	9.4	50%	30%	15%	8	
VOC	T10-T20	10	84.9	14.2	50%	35%	18%	12	
VOC	T20-T30	10	3.5	0.6	50%	50%	25%	0.4	
VOC	T30-T40	10	3.5	0.6	50%	75%	38%	0.4	
VOC	T40-T50	10	3.5	0.6	50%	90%	45%	0.3	
VOC	T50-T60	10	3.5	0.6	50%	100%	50%	0.3	
VOC	**Total Startup**							21	25

Combined Cycle: Summary of Start-Up and Shutdown Emissions Estimates
October 2015
Hot/Warm Start

20 deg F									
Pollutant	**Startup**	**Duration (min)**	**Catalyst Inlet (lb/hr)**	**Inlet Over Duration (lbs)**	**Design Reduction (%)**	**Transient Reduction (%)**	**Net Reduction (%)**	**Total Outlet (lbs)**	**Emissions per Event (lbs)**
NO_x	T0-T10	10	64	11	80%	40%	32%	7	
NO_x	T10-T20	10	95	16	80%	90%	72%	4	
NO_x	T20-T30	10	75	13	80%	100%	80%	3	
NO_x	**Total Startup**							14	17
CO	T0-T10	10	738	123	80%	75%	60%	49	
CO	T10-T20	10	1351	225	80%	90%	72%	63	
CO	T20-T30	10	59	10	80%	100%	80%	2	
CO	**Total Startup**							114	137
VOC	T0-T10	10	84	14	50%	75%	38%	9	
VOC	T10-T20	10	127	21	50%	90%	45%	12	
VOC	T20-T30	10	5.3	0.9	50%	100%	50%	0.4	
VOC	**Total Startup**							21	25

59 deg F									
Pollutant	**Startup**	**Duration (min)**	**Catalyst Inlet (lb/hr)**	**Inlet Over Duration (lbs)**	**Design Reduction (%)**	**Transient Reduction (%)**	**Net Reduction (%)**	**Total Outlet (lbs)**	**Emissions per Event (lbs)**
NO_x	T0-T10	10	63	11	80%	40%	32%	7	
NO_x	T10-T20	10	86	14	80%	90%	72%	4	
NO_x	T20-T30	10	68	11	80%	100%	80%	2	
NO_x	**Total Startup**							13	16
CO	T0-T10	10	646	108	80%	75%	60%	43	
CO	T10-T20	10	1183	197	80%	90%	72%	55	
CO	T20-T30	10	52	9	80%	100%	80%	2	
CO	**Total Startup**							100	120
VOC	T0-T10	10	79	13	45%	75%	34%	9	
VOC	T10-T20	10	118	20	45%	90%	41%	12	
VOC	T20-T30	10	5	0.8	45%	100%	45%	0.5	
VOC	**Total Startup**							21	25

100 deg F									
Pollutant	**Startup**	**Duration (min)**	**Catalyst Inlet (lb/hr)**	**Inlet Over Duration (lbs)**	**Design Reduction (%)**	**Transient Reduction (%)**	**Net Reduction (%)**	**Total Outlet (lbs)**	**Emissions per Event (lbs)**
NO_x	T0-T10	10	62	10	80%	40%	32%	7	
NO_x	T10-T20	10	75	13	80%	90%	72%	4	
NO_x	T20-T30	10	62	10	80%	100%	80%	2	
NO_x	**Total Startup**							13	15
CO	T0-T10	10	501	83	80%	75%	60%	33	
CO	T10-T20	10	917	153	80%	90%	72%	43	
CO	T20-T30	10	40	7	80%	100%	80%	1	
CO	**Total Startup**							78	93
VOC	T0-T10	10	57	9	45%	75%	34%	6	
VOC	T10-T20	10	85	14	45%	90%	41%	8	
VOC	T20-T30	10	4	1	45%	100%	45%	0.3	
VOC	**Total Startup**							15	18

Combined Cycle: Summary of Start-Up and Shutdown Emissions Estimates
October 2015
Shutdown

20 deg F

Pollutant	Shutdown	Duration (min)	Catalyst Inlet (lb/hr)	Inlet Over Duration (lbs)	Design Reduction (%)	Transient Reduction (%)	Net Reduction (%)	Total Outlet (lbs)	Emissions per Event (lbs)
NO_x	T0-T10	10	53	9	80%	100%	80%	2	
NO_x	T10-T20	10	17	3	80%	100%	80%	0.6	
NO_x	T20-T30	10	100	17	80%	80%	64%	6	
NO_x	**Total Shutdown**							8	10
CO	T0-T10	10	1531	255	80%	100%	80%	51	
CO	T10-T20	10	1092	182	80%	100%	80%	36	
CO	T20-T30	10	439	73	80%	85%	68%	23	
CO	**Total Shutdown**							111	133
VOC	T0-T10	10	128	21	50%	100%	50%	11	
VOC	T10-T20	10	168	28	50%	100%	50%	14	
VOC	T20-T30	10	21	3	50%	85%	43%	2	
VOC	**Total Shutdown**							27	32

59 deg F									
Pollutant	**Shutdown**	**Duration (min)**	**Catalyst Inlet (lb/hr)**	**Inlet Over Duration (lbs)**	**Design Reduction (%)**	**Transient Reduction (%)**	**Net Reduction (%)**	**Total Outlet (lbs)**	**Emissions per Event (lbs)**
NO_x	T0-T10	10	44	7	80%	100%	80%	1	
NO_x	T10-T20	10	16	3	80%	100%	80%	0.5	
NO_x	T20-T30	10	92	15	80%	80%	64%	6	
NO_x	**Total Shutdown**							8	9
CO	T0-T10	10	1229	205	80%	100%	80%	41	
CO	T10-T20	10	1057	176	80%	100%	80%	35	
CO	T20-T30	10	430	72	80%	85%	68%	23	
CO	**Total Shutdown**							99	119
VOC	T0-T10	10	81	13	45%	100%	45%	7	
VOC	T10-T20	10	162	27	45%	100%	45%	15	
VOC	T20-T30	10	19	3	45%	85%	38%	2	
VOC	**Total Shutdown**							24	29

100 deg F									
Pollutant	**Shutdown**	**Duration (min)**	**Catalyst Inlet (lb/hr)**	**Inlet Over Duration (lbs)**	**Design Reduction (%)**	**Transient Reduction (%)**	**Net Reduction (%)**	**Total Outlet (lbs)**	**Emissions per Event (lbs)**
NO_x	T0-T10	10	30	5	80%	100%	80%	1.0	
NO_x	T10-T20	10	18	3	80%	100%	80%	0.6	
NO_x	T20-T30	10	85	14	80%	80%	64%	5	
NO_x	**Total Shutdown**							7	8
CO	T0-T10	10	758	126	80%	100%	80%	25	
CO	T10-T20	10	1014	169	80%	100%	80%	34	
CO	T20-T30	10	408	68	80%	85%	68%	22	
CO	**Total Shutdown**							81	97
VOC	T0-T10	10	49	8	45%	100%	45%	5	
VOC	T10-T20	10	148	25	45%	100%	45%	14	
VOC	T20-T30	10	18	3	45%	85%	38%	2	
VOC	**Total Shutdown**							20	24