DOCKETED

Docket Number:	12-AFC-02C
Project Title:	Huntington Beach Energy Project - Compliance
TN #:	214533
Document Title:	Huntington Beach Energy Project (HBEP) Final Determination of Compliance (FDOC) Package
Description:	HBEP - Final Determination of Compliance (FDOC) Package
Filer:	Catherine Rodriguez
Organization:	South Coast Air Quality Management District
Submitter Role:	Public Agency
Submission Date:	11/18/2016 5:24:48 PM
Docketed Date:	11/18/2016

Final
Determination of Compliance

Huntington Beach Energy Project

South Coast Air Quality Management District

November 2016

APPLICANT:

AES Huntington Beach, LLC
21730 Newland St
Huntington Beach, CA 92646
SCAQMD ID# 115389

EQUIPMENT LOCATION:

21730 Newland St
Huntington Beach, CA 92646

EQUIPMENT DESCRIPTION:

Section H of the Facility Permit ID# 115389

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
GAS TURBINE, UNIT NO.1, COMBINED CYCLE, GE MODEL 7FA.05, NATURAL GAS, 2273 MMBTU AT 32 DEGREES F WITH DRY LOW NOX COMBUSTOR, GE DLN 2.6 A/N: 578073 GENERATOR, 236.1 MW GROSS AT 32 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NO. 2, 221.4 MW GROSS AT 32 DEGREES F	D115 (B116) (B117) (B118)	C120, C121, S123	NOX: MAJOR SOURCE SOX; PROCESS UNIT	**CO**: ~~2.0~~ **1.5** PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **CO2**: 1,000 LBS/GROSS MWH NATURAL GAS (8) [40 CFR60 SUBPART TTTT] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 2005, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: ~~19.09~~ **16.66** LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **8.5 LBS/HR (5B) [RULE 1303 OFFSETS]**	A63.6, A63.7, A99.4., A195.6, A195.7, A195.8 A195.9, A327.1, B61.1, C1.7, C1.8, C1.9, D29.5, D29.6, D29.7, D82.3 D82.4, E193.3, E193.4, E193.5, E193.6, E448.1, I297.1, I298.1, K40.3, K67.5

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				SOX: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK]; SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.71 LBS/MMCF NATURAL GAS (1) [RULE 2011]	
CO OXIDATION CATALYST, BASF, SERVING GAS TURBINE NO. 1, WITH 328.8 CU. FEET OF TOTAL CATALYST VOLUME A/N: 578075	C120	D115			D12.10, **E193.3**, E193.4
SELECTIVE CATALYTIC REDUCTION, CORMETECH, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.1, 2761 CU. FEET OF TOTAL CATALYST VOLUME, 25.7' L X 1.5' W. X 71.6' H., WITH A/N: 578075 AMMONIA INJECTION, INJECTION GRID	C121 (B122)	D115		**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	A195.10, D12.7, D12.8, D12.9, **E193.3**, E193.4
STACK SERVING UNIT NO. 1, 150' H. X 20' DIA. A/N: 578073	S123	D115			
GAS TURBINE, UNIT NO.2, COMBINED CYCLE, GE MODEL 7FA.05, NATURAL GAS, 2273 MMBTU AT 32 DEGREES F WITH DRY LOW NOX COMBUSTOR, GE DLN 2.6 A/N: 578074 GENERATOR, 236.1 MW GROSS AT 32 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS	D124 (B125) (B126) (B127)	C129 C130 S132	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO**: ~~2.0~~ **1.5** PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **CO2**: 1,000 LBS/GROSS MWH NATURAL GAS (8) [40 CFR60 SUBPART TTTT] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 2005, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: ~~19.09~~ **16.66** LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT]	A63.6, A63.7, A99.4., A195.6, A195.7, A195.8 A195.9, A327.1, B61.1, C1.7, C1.8, C1.9, D29.5, D29.6, D29.7, D82.3 D82.4, E193.3, E193.4, E193.5, E193.6,

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
TURBINE NO. 1, 221.4 MW GROSS AT 32 DEGREES F				**PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **8.5 LBS/HR (5B) [RULE 1303 OFFSETS]** **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.71 LBS/MMCF NATURAL GAS (1) [RULE 2011]	E448.1, I297.1, I298.1, K40.3, K67.5
CO OXIDATION CATALYST, BASF, SERVING GAS TURBINE NO. 2, WITH 328.8 CU. FEET OF TOTAL CATALYST VOLUME A/N: 578076	C129	D124			D12.10, **E193.3**, E193.4
SELECTIVE CATALYTIC REDUCTION, CORMETECH, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.2, 2761 CU. FEET OF TOTAL CATALYST VOLUME, 25.7' L X 1.5' W. X 71.6' H., WITH A/N: 578076 AMMONIA INJECTION, INJECTION GRID	C130 (B131)	D124		**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	A195.10, D12.7, D12.8, D12.9, **E193.3**, E193.4
STACK SERVING UNIT NO. 2, 150' H. X 20' DIA. A/N: 578074	S132	D124			
GAS TURBINE, UNIT NO.3, SIMPLE CYCLE, GE MODEL LMS100PB, NATURAL GAS, 885 MMBTU AT 65.8 DEGREES F, INTERCOOLED, WITH DRY LOW NOX COMBUSTOR A/N: 578077 GENERATOR, 100.8 MW GROSS AT 65.8 DEGREES F	D133 (B134)	C135, C136, S138	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO**: ~~4.0~~ **2.0** PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.5 PPM NATURAL GAS (4) [RULE 2005, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 25.11 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT]	A63.8, A63.9, A99.5, A195.8, A195.11, A195.12, A327.1, B61.1, C1.10, C1.11, C1.12, D29.5, D29.6, D29.7, D82.3

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **6.24 LBS/HR (5B) [RULE 1303 OFFSETS]** **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.71 LBS/MMCF NATURAL GAS (1) [RULE 2011]	D82.4, E193.3, E193.4, E193.7, E193.8, E448.1, E448.2, E448.3, I297.2, I298.2, K40.3, K67.6
CO OXIDATION CATALYST, BASF CAMET, SERVING GAS TURBINE NO. 3, WITH 165.6 CU. FEET OF TOTAL CATALYST VOLUME A/N: 578079	C135	D133			D12.17, **E193.3**, E193.4
SELECTIVE CATALYTIC REDUCTION, CORMETECH CMHT, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.3, WITH 622 CU. FEET OF TOTAL CATALYST VOLUME, 11' L. X 4.9' W. X 11.5' H, WITH A/N: 578079 AMMONIA INJECTION, INJECTION GRID	C136 (B137)	D133		**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	A195.10, D12.11, D12.12, D12.13, **E193.3**, E193.4
STACK SERVING UNIT NO. 3, 80' H. X 13.5' DIA. A/N: 578077	S138	D133			
GAS TURBINE, UNIT NO.4, SIMPLE CYCLE, GE MODEL LMS100PB, NATURAL GAS, 885 MMBTU AT 65.8 DEGREES F, INTERCOOLED, WITH DRY LOW NOX COMBUSTOR A/N: 578078 GENERATOR, 100.8 MW GROSS AT 65.8 DEGREES F	D139 (B140)	C141, C142, S144	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO**: ~~4.0~~ **2.0** PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.5 PPM NATURAL GAS (4) [RULE 2005, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 25.11 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT]	A63.8, A63.9, A99.5, A195.8, A195.11, A195.12, A327.1, B61.1, C1.10, C1.11, C1.12, D29.5, D29.6, D29.7, D82.3

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **<u>6.24 LBS/HR (5B) [RULE 1303 OFFSETS]</u>** **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.71 LBS/MMCF NATURAL GAS (1) [RULE 2011]	D82.4, E193.3, E193.4, E193.7, E193.8, E448.1, E448.2, E448.3, I297.2, I298.2, K40.3, K67.6
CO OXIDATION CATALYST, BASF CAMET, SERVING GAS TURBINE NO. 4, WITH 165.6 CU. FEET OF TOTAL CATALYST VOLUME A/N: 578080	C141	D139			D12.17, **<u>E193.3</u>**, E193.4
SELECTIVE CATALYTIC REDUCTION, CORMETECH CMHT, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.4, WITH 622 CU. FEET OF TOTAL CATALYST VOLUME, 11’ L. X 4.9’ W. X 11.5’ H, WITH A/N: 578080 AMMONIA INJECTION, INJECTION GRID	C142 (B143)	D139		**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	A195.10, D12.11, D12.12, D12.13, **<u>E193.3</u>**, E193.4
STACK SERVING UNIT NO. 4, 80’ H. X 13.5’ DIA. A/N: 578078	S144	D139			
BOILER, AUXILIARY, RENTECH, MODEL D-TYPE, WATER TUBE, NATURAL GAS, 71 MMBTU/HR, WITH LOW NOX BURNER, FLUE GAS RECIRCULATION, WITH A/N: 578081 BURNER, JZHC/COEN RMB, 71 MMBTU/HR, NATURAL GAS WITH LOW	D145 (B146)	C147, S149	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO**: 50 PPM NATURAL GAS (4) [RULE 1303(a)(1) - BACT]; CO: 400 PPM (5) [RULE 1146]; CO: 2000 PPM (5A) [Rule 407] **NOX**: 5.0 PPM NATURAL GAS (4) [RULE 2005]; NOX: 49.180 LBS/MMCF NATURAL GAS (1) [RULE 2012] **PM**: 0.1 GR/SCF (5) [RULE 409];	A63.10, A195.13, A195.14, **<u>B61.1</u>**, C1.13, C1.14, **<u>D29.6</u>**, D29.8, D29.9, D82.5, **<u>E193.3</u>** E193.4, I297.3, I298.3, **<u>K40.4</u>**

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
NOX BURNER, FLUE GAS RECIRCULATION				**SOX**: SOX: 0.83 LBS/MMCF NATURAL GAS (1) [RULE 2011]	
SELECTIVE CATALYTIC REDUCTION, BABCOCK AND WILCOX, VANADIUM, SERVING THE AUXILIARY BOILER, WITH 46 CU. FEET OF TOTAL CATALYST VOLUME, WITH A/N: 578082 AMMONIA INJECTION, INJECTION GRID	C147 (B148)	D145		**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	A195.~~10~~ **15**, D12.14, D12.15, D12.16, **E193.3**, E193.4
STACK SERVING AUXILIARY BOILER, 80' H. X 3' DIA. A/N: 578081	S149	D145			
PROCESS 4: AMMONIA STORAGE					
STORAGE TANK, HORIZONTAL, 45' L X 13' DIA, AQUEOUS AMMONIA 19%, 35000 GALS A/N: 578083	D150				E144.1, C157.1, **E193.3**, E193.4
STORAGE TANK, HORIZONTAL, 18' L X 6' DIA, AQUEOUS AMMONIA 19%, 15000 GALS A/N: 578084	D151				E144.1, C157.1, **E193.3**, E193.4
PROCESS 5: WASTE WATER TREATMENT					
OIL WATER SEPARATOR A/N: 578085	D152				
OIL WATER SEPARATOR A/N: 578086	D153				

BACKGROUND:

On October 29, 2014, the CEC granted a license to AES for the construction and operation of the HBEP (original configuration). After the CEC issued the HBEP final decision, Southern California Edison announced that AES had been awarded a contract to provide 644 MWs of nominal capacity at the Huntington Beach site. The project configuration selected by SCE required a change to the original HBEP design, thus AES has resubmitted applications to the SCAQMD, and also requested a modification of the CEC license for the new design.

The amended Huntington Beach Energy Project (HBEP) is a proposed 895.5 MW combined cycle/simple cycle power plant to be located at the existing site of the Huntington Beach Generating Station plant in Huntington Beach, approximately 900 feet from the Pacific Ocean. The surrounding area is a mix of residential, wetland preserve, public beach, and industrial, 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 the 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 30 of those acres. The nearest inhabitants to the proposed project site is a residential area approximately 300-400 feet from the site. The site location map is presented in Figure 1.1. The HBEP plot plan is presented in Appendix J.

The current Huntington Beach facility consists of 2 utility boilers. Boilers 1 and 2 are identical units, each rated at 215 MWs output and 2021 mmbtu/hr input. The boilers are equipped with SCR systems, and are fired primarily on pipeline natural gas, with some field gas from offshore platforms also combusted. The boilers were built in the 1950's and use 'once-through' ocean water cooling. There are two 275 hp diesel-fueled emergency engines 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 shutdown and no longer operates, as well as Boilers 3 and 4, which have also been shutdown.

The current ownership of the equipment at the site is split between AES Huntington Beach, LLC which owns Boilers 1 and 2, the two the 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 Huntington Beach is the operator for all the equipment on site.

It should be noted that the shutdown of Boilers 3 and 4 are not a part of the HBEP. The capacity for these units were replaced by a power project in the City of Industry, not owned or operated by AES.

The proposed new facility will be composed of two separate power blocks, a combined cycle block and a simple cycle block. Construction of the combined cycle block is expected to begin in the second quarter of 2017 (outside of some demolition activities and site prep), and construction of the simple cycle block is anticipated in the second quarter of 2022. First fire of the combined cycle power block is expected by 10/1/2019. To offset the generating capacity of the new combined cycle plant, AES will shutdown Boiler 1 at the Huntington Beach plant, and Boiler 7 at the AES Redondo Beach plant by 11/1/2019, which is within 30 days of the new plant coming on line. Both the AES Huntington Beach and AES Redondo Beach plants are wholly-owned subsidiaries of AES Southland Corporation.

First fire of the new simple cycle power block is expected on 11/1/2023. To offset the capacity of the simple cycle plant, AES will shutdown Boiler 2 at the Huntington Beach plant.

Table 1.1 Construction Schedule

Activity	Timeframe
Demolition of Unit 5 Peaker and East Oil Tank	First QTR 2016
Site Prep and Grading	Fourth QTR 2016
Begin Construction of CCGT	Second QTR 2017
Commercial Operation of Block 1	First/Second QTR 2020
Demolition of Units 3 and 4	First/Second QTR 2020
Begin Construction of SCGT	Second QTR 2022
Commercial Operation of SCGT	First QTR 2024
Demolition of Units 1 and 2	First QTR 2024

Table 1.2 Start Up/Shut Down Dates

New Units	Capacity, MWs	First Fire Date	Retired Units	Capacity, MWs	Shutdown Date
Combined Cycle Block	693.8	10/1/2019	HBGS 1	215	11/1/2019
			RBGS 7	480	11/1/2019
Simple Cycle Block	201.6	11/1/2023	HBGS 2	215	12/31/2020

Total generating capacity being retired as part of this project is 910 MWs. Prior to the start of construction of the new plant, the facility will be required to submit a comprehensive decommissioning plan for the boilers to be shutdown. In accordance with SCAQMD policy, decommissioning must render the units permanently inoperable.

The combined cycle block will consist of two GE 7FA.05 turbine generators (CCTG), a heat recovery steam generator (HRSG), and one steam turbine. The simple cycle power block will consist of two GE LMS100PB turbine generators (SCTG). The turbines will be air cooled. An auxiliary boiler will be used to assist the CCTG during start up. All combustion units will be fired on natural gas exclusively (platform field gas will no longer be used at the site).

Other equipment includes a 35,000 gallon aqueous ammonia storage tank serving the CCTG and auxiliary boiler, a 15,000 gallon aqueous ammonia storage tank serving the SCTG, and 2 oil/water separators. The 2 existing emergency fire pump engines will remain in operation.

AES Huntington Beach, LLC 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 adjacent to the property (to the north-east). Output will depend on market conditions and dispatch requirements. The plant's expected availability is over 98% on an annual basis, with the actual capacity factor anticipated to be between 45-75%[1]. 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 about 60 minutes for the combined cycle power block and 30 minutes for the simple cycle power block – ramp quickly, and operate fully controlled at high turndown ratios.

The following applications for the project were submitted on September 8, 2015:

Table 1.3 – Project Application Numbers

Application Number	Equipment Description
578073	Combined Cycle Turbine #1
578074	Combined Cycle Turbine #2
578075	SCR/CO Catalyst #1
578076	SCR/CO Catalyst #2
578077	Simple Cycle Turbine #3
578078	Simple Cycle Turbine #4
578079	SCR/CO Catalyst #3
578080	SCR/CO Catalyst #4
578081	Auxiliary Boiler
578082	Auxiliary Boiler SCR
578083	Ammonia Storage
578084	Ammonia Storage
578085	Oil/Water Separation
578086	Oil/Water Separation
578087	Title V Revision

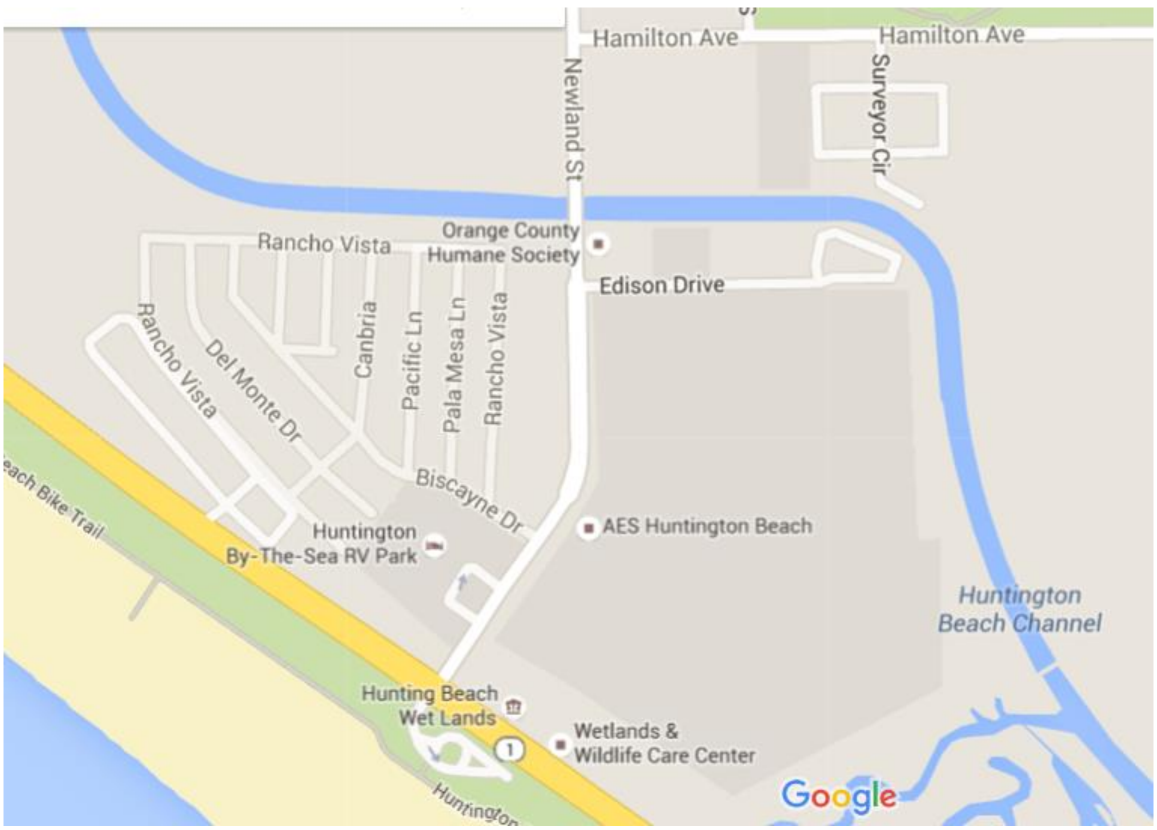
Additional information for the project was received on October 13, 2015, November 11, 2015, and December 4, 2015. SCAQMD deemed the applications complete on December 18, 2015. On March 14, 2016, the facility proposed changes to the equipement operating profile and submitted an application revision. Refer to Appendix R for fees paid.

The plant will be evaluated as 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 NOx and SOx

[1] The maximum annual generation is estimated to be approximately ~~4,744~~ **4,434** gigawatt hrs **(net)**, based on an average baseload rating of 681.7 MW and ~~6,612~~ **6,100** hrs/yr for the combined cycle block, and ~~179.4~~ **198.7** MW and 1,750 hrs for the simple cycle block, and 98.4% availability.

RECLAIM and PSD regulations for NO2, SOx, CO, GHG, and PM10. The plant is considered a major revision to a major stationary source under Regulation XIII and Rule 2005, and as such is subject to the full requirements of New Source Review. Other major environmental regulations that apply to the new project are 40 CFR72 – Acid Rain, 40CFR 60 Subpart KKKK – New Source Performance Standards for Gas Turbines, 40CFR 60 Subpart TTTT GHG Standards for Electric Utility Generating Units, and AQMD Rule 1401 – Toxics. The project is also subject to the California Energy Commissioning (CEC) licensing procedure and an Application for Certification (AFC) has been submitted with that agency (12-AFC-02C).

Figure 1.1 –Site Location



Compliance History

The following information was obtained from the District's Compliance Tracking System for the 5-year period from 1/01/10 to 2/04/16 for the AES Huntington Beach facility.

Notice to Comply D03529

Issued 12/01/10 for failure to include all equipment in the RECLAIM quarterly reports (QCER). The follow up status is 'in compliance.'

Notice to Comply E09956
Issued 10/14/11 for failure to comply with testing condition D28.3 and D29.3 including testing for a 60 minute period. The follow up status is 'in compliance.'

Notice of Violation P52182
Issued on 10/27/11 for exceeding the start up NOx limit of 38.4 lbs/hr for Boiler #4. This is a closed case.

Notice of Violation P60564
Issued on 12/30/15 for the late submittal of the 2/17/15 electronic emissions report for Boiler #2. This is a closed case.

Notice of Violation P58099
Issued on 2/2/16 for failure to submit the Title V renewal application in a timely manner.

There were no complaints associated with the facility for the stated time period in the AQMD database. The facility has also submitted a statement certifying that all facilities owned and operated in the state are currently in compliance with all applicable air quality regulations, as required by Rule 1303.

PROCESS DESCRIPTION:

The two GE7FA.05 combined cycle turbines will be arranged in a 'two-on-one' (2X1) configuration. Each turbine is rated at 232.1 MW (nominal gross), and will be equipped with dry low NOx combustors and evaporative inlet air cooling, a heat recovery steam generator (no duct firing), an SCR and oxidation catalyst, and one 229.7 MW (nominal gross) steam turbine, common to both combustion turbines.

Each combined cycle turbine will vent to a stack 150 feet tall. 19% aqueous ammonia for the combined cycle turbine SCRs will be stored in a 35,000 gallon tank.

An auxiliary boiler will be employed to assist the combined cycle units during start ups. The boiler is rated at 71 mmbtu/hr and will be fired on natural gas. It will be equipped with Low NOx burners, Flue Gas Recirculation, and an SCR.

The two GE LMS100PB simple cycle turbines are each rated at 100.8 MWs (nominal gross), and will be equipped with dry low NOx combustors, SCRs and oxidation catalysts.

Each simple cycle turbine will vent to a stack 80 feet tall. 19% aqueous ammonia for the simple cycle turbine SCRs will be stored in a 15,000 gallon tank.

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. The tables below show the output on a per turbine basis.

Table 2.1 Combined Cycle Plant 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/h HHV	2,240	2,123	2,273	2,248
Gas Turbine Gross Output[1], kW	231,197	215,890	236,140	232,073
Steam Turbine Gross Output[2], kW	115,470	96,702	110,675	114,838
Total Gross Power Output[3], kW	346,667	312,592	346,815	346,911
Net Power Output[3], 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
Net Plant Efficiency, %, LHV	57.2	54.4	56.7	57.0
Net Plant Efficiency, %, HHV	51.9	49.4	51.1	51.7

1 *on a per turbine basis*
2 *one half of the total steam turbine output*
3 *multiply by 2 to get the output per power block*

Table 2.2 Simple Cycle Plant Output Per Turbine

	110 F-8% RH (Evaporative Cooling On)	32 F – 87% RH (Evaporative Cooling Off)	65.8 F – 58% RH (Evaporative Cooling On)
Gas Turbine Heat Input, mmbtu/h 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
Net Plant Efficiency, %, LHV	39.1	42.6	42.6
Net Plant Efficiency, %, HHV	35.2	38.4	38.3

There will be no new offsite transmission lines or gas lines needed for the project.

Each of the components is discussed in more detail below:

- *Combined Cycle Combustion Turbines*

The 7FA.05 turbine is the upgraded '5th generation' version of GE's 7FA frame unit. It features fast start capability (20 minutes to baseload for a cold start, and 15 minutes to baseload for a non-cold start), high turndown ratio (approximately 44%), and increased output and efficiency over the previous generation 7FAs. The fast start capability in combined cycle mode is accomplished by decoupling the combustion turbine from the HRSG and steam turbine, thus bypassing the time needed to allow the steam turbine to achieve operating temperature. The improved efficiency is a result of hot gas path enhancements and the compressor design, including variable geometry blades, different blade materials, and improved blade aerodynamics.

The turbines will be equipped with inlet air filters, inlet air compressors, and evaporative coolers. Incoming combustion gas will first pass through the facility's compression station and be brought to a pressure of approximately 600 psi prior to combustion.

Heat input for each combustion turbine at maximum low temperature conditions is 2,273 mmbtu/hr (HHV), fuel use at these conditions is approximately 2.16 mmcf/hr, based on a natural gas heat content of 1050 btu/cf. Turbines specs are summarized in the following table:

Table 2.3 Combined Cycle Turbine Data

Specification	
CT Manufacturer	GE
Model	7FA.05
Fuel Type	Pipeline natural gas
Maximum Power Output	236.1 MW (1 turbine @ 32° F)
Maximum Heat Input	2,273 mmbtu/hr HHV (1 turbine @ 32° F)
Maximum Fuel Consumption	2.16 mmcf/hr HHV (1 turbine @ 32° F, 1050 btu/cf)
Maximum Exhaust Flow[1]	70.1 mmcfhr, dry @ 15% O2 (1 turbine @ 32° F)
NOx Combustion Control	DLN 9 ppm
Steam Turbine Output at 63°F Ambient	221.4 MW (@ 32 deg)
Net Plant Heat Rate, LHV	6,017 btu/kWh @ 32° F
Net Plant Heat Rate, HHV	6,672 btu/kWh @ 32° F
Net Plant Efficiency, HHV	51.1%

1 - estimated using an F-factor of 8710 corrected to 15% O2

Each turbine will exhaust to a Heat Recovery Steam Generator (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 1100 deg F. The HRSG's employ a triple pressure design. Feed water into the HRSG will be converted to high, intermediate, and low pressure steam for use in the triple pressure 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. The SCR and oxidation catalyst will be contained within the HRSG.

- *CCTG Air Pollution Control (APC) Equipment*

APC equipment will be installed to control NOx, CO, and VOC from the gas turbines. Each APC system will consist of the following: 1) Dry Low NOx (DLN) Combustor, 2) SCR, and 3) Oxidation catalyst.

Dry Low NOx Combustor - Each CT will be equipped with GE's DLN 2.6 combustor to reduce NOx emissions to 9 parts-per-million volume dry basis (ppmvd) at 15 percent oxygen (O_2). The dry low NOx control will be fully operational when the turbine reaches a load of approximately 44 percent or more.

Oxidation Catalyst System – The units will employ a palladium-type oxidation catalyst designed to reduce exhaust gas CO by about 70-85% to ~~2.0~~ **1.5** ppm or less at 15% O2, and VOC by 50-60% to 2.0 ppm at 15% O2 (1 hour average).

Table 2.4 CCTG Oxidation Catalyst Data

Specification	
Manufacturer	BASF
Catalyst Type	Palladium in a honeycomb structure
Catalyst Volume	328.8 ft^3
Catalyst Area	1,879 ft^2
Catalyst Dimensions	2.1"W X 26.2'L X 71.8'H
Space Velocity	213,200 hr^{-1}
Area Velocity	37,307 ft/hr
CO Removal Efficiency	70-85%
Outlet CO	~~2.0~~ **1.5** ppmvd at 15% O2 1 hour average
VOC Removal Efficiency	50-60%
Outlet VOC	2.0 ppmvd at 15% O2 1 hour average
Minimum operating temperature	570 °F

Space and area velocities based on an exhaust flow rate of 70.1 mmscf/hr

Selective Catalytic Reduction System – The SCR will be designed to reduce NOx emissions to 2.0 ppmvd at 15% O2 on a 1 hour average basis. 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. Multiple SCR modules are arranged in 1 layer of catalyst approximately 1.5' deep. Total catalyst volume is about 2,761 ft3. Aqueous ammonia (ammonium hydroxide at 19% concentration by weight) from the storage tank will be vaporized, diluted with air, and injection into the exhaust through an injection grid. The amount of ammonia injected will vary depending on NOx reduction requirements, but will be approximately a 1:1 to 1:1.2 molar ratio of ammonia to incoming NOx.

Table 2.5 CCTG SCR Catalyst Data

Specification	
Manufacturer	Cormetech
Catalyst Type	Titanium/Vanadium/Tungsten honeycomb
Catalyst Volume	2,761.3 ft^3
Catalyst Area	1,841 ft^2
Catalyst Dimensions	1.5'W X 25.71'L X 71.6'H
Space Velocity	25,387 hr^{-1}
Area Velocity	38,077 ft/hr
Ammonia Injection Rate	32 gph, 242 lbm/hr of 19% NH3
Ammonia Slip	5.0 ppm
Outlet NOx	2.0 ppm at 15% 1 hour average
Guarantee	25,000 hours of operation, or 5 years
SCR/CO catalyst Total Cost	$1 million
Operating temperature range	570 °F-692°F

Space and area velocities based on an exhaust flow rate of 70.1 mmscf/hr.

- *Exhaust Stacks*

Each turbine/HRSG will be equipped with identical 20-foot diameter 150 feet tall stacks. The stacks will contain sampling ports for exhaust gas testing.

Table 2.6 CCTG Stack Data

Specification	
Stack Diameter	20 feet
Stack Height	150 feet
Stack Area	314.2 ft^2
Exhaust gas temperature	194 deg F
Exhaust gas velocity	4,017 feet/min @ 32 deg F

- *Simple Cycle Combustion Turbines*

The GE LMS100PB units are aeroderivative turbines which feature fast start capability and load following ability. The turbines will be equipped with inlet air filters, inlet air compressors, and evaporative coolers. The turbines are intercooled. Combustion air is compressed in two stages, and water cooled between stages back to its initial temperature. This reduces the volume of air and the work required to compress it. Water used in the intercooling is cooled in a fin-fan heat exchanger. Incoming combustion gas will be compressed to approximately 600 psi prior to combustion.

Heat input for each combustion turbine at nominal (site average temperature) is 885 mmbtu/hr (HHV), fuel use at these conditions is approximately 0.84 mmcf/hr, based on a natural gas heat content of 1050 btu/cf. Turbines specs are summarized in the following table:

Table 2.7 Simple Cycle Turbine Data

Specification	
CT Manufacturer	GE
Model	LMS 100PB
Fuel Type	Pipeline natural gas
Maximum Power Output	100.8 MW (1 turbine @ 65.8°F)
Maximum Heat Input	885 mmbtu/hr HHV (1 turbine @ 65.8°F)
Maximum Fuel Consumption	0.84 mmcf/hr HHV (1 turbine @ 65.8°F, 1050 btu/cf)
Maximum Exhaust Flow[1]	27.3 mmcf/hr, dry @ 15% O2 (1 turbine @ 65.8° F)
NOx Combustion Control	DLN 25 ppm
Net Plant Heat Rate, LHV	8,027 btu/kWh @ 65.8° F
Net Plant Heat Rate, HHV	8,910 btu/kWh @ 65.8° F
Net Plant Efficiency, HHV	38.3%

1 - estimated using an F-factor of 8710 corrected to 15% O2

Emissions will be minimized with the use of dry low NOx combustors, SCR and oxidation catalysts.

- *SCTG Air Pollution Control (APC) Equipment*

Dry Low NOx Combustor - The PB units are equipped with dry low NOx combustors. The combustor will produce NOx emissions at 25 parts-per-million volume dry basis (ppmvd) at 15 percent oxygen (O_2). The dry low NOx control will be fully operational when the turbine reaches a load of approximately 44 percent or more.

Oxidation Catalyst System – An oxidation catalyst will be installed in the exhaust section of the turbine. The catalyst is designed for maximum surface contact with the gas flow, and has a thickness of only 2.5 inches. The catalyst is sized to reduce exhaust gas CO by about 90-96% to ~~4.0~~ **2.0** ppm or less at 15% O2, and VOC by 50-60% to 2.0 ppm at 15% O2 (1 hour averages).

Table 2.8 SCTG Oxidation Catalyst Data

Specification	
Manufacturer	BASF Camet
Catalyst Type	Palladium in a honeycomb structure
Catalyst Volume	165.6 ft^3
Catalyst Area	794.8 ft^2
Catalyst Dimensions	0.21’ W X 2.1’L X 2’H (each module, 187 total modules)

Space Velocity	164,855 hr^{-1}
Area Velocity	34,348 ft/hr
CO Removal Efficiency	90-96%
Outlet CO	~~4.0~~ **2.0** ppmvd at 15% O2 1 hour average
VOC Removal Efficiency	50-60%
Outlet VOC	2.0 ppmvd at 15% O2 1 hour average
Minimum operating temperature	500 °F

Space and area velocities based on an exhaust flow rate of 27.3 mmscf/hr

Selective Catalytic Reduction System – An SCR catalyst will be installed in the exhaust downstream from the oxidation catalyst to reduce NOx emissions to 2.5 ppmvd at 15% O2 on a 1 hour average basis. The SCR catalyst will consist of a vanadium/titanium/tungsten type catalyst in a honeycomb structure. Total catalyst volume is about 622 ft3. Aqueous ammonia (ammonium hydroxide at 19% concentration by weight) from the storage tank will be vaporized, diluted with air, and injection into the exhaust through an injection grid. The amount of ammonia injected will vary depending on NOx reduction requirements, but will be approximately a 1:1 to 1:1.2 molar ratio of ammonia to incoming NOx.

Table 2.9 SCTG SCR Catalyst Data

Specification	
Manufacturer	Cormetech CMHT
Catalyst Type	Titanium/Vanadium/Tungsten honeycomb
Catalyst Volume	622 ft^3
Catalyst Area	126.5 ft^2
Catalyst Dimensions	4.9" W X 11.5'L X 11'H
Space Velocity	43,891 hr^{-1}
Area Velocity	215,810 ft/hr
Ammonia Injection Rate	24 gph, 180 lbm/hr of 19% NH3
Ammonia Slip	5.0 ppm
Outlet NOx	2.5 ppm at 15%
Guarantee	24,000 hours of operation, or 3 years
SCR/CO catalyst Total Cost	$1.1 million
Operating temperature range	500 °F-870°F

Space and area velocities based on an exhaust flow rate of 27.3 mmscf/hr

- *Exhaust Stacks*

Each simple cycle turbine will be equipped with identical 13.5-foot diameter 80 feet tall stacks. The stacks will contain sampling ports for exhaust gas testing.

Table 2.10 SCTG Stack Data

Specification	
Stack Diameter	13.5 feet
Stack Height	80 feet
Stack Area	143.1 ft^2
Exhaust gas temperature	853 deg F
Exhaust gas velocity	6,551 feet/min @ 32 deg F

- *Monitoring Systems*

All four turbines will be equipped with in-stack continuous emission monitors for NOx, CO, and O2, along with individual fuel meters. A data acquisition system is required to collect information from the analyzers and fuel meters to calculate exhaust flows and mass emissions of NOx 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, turbine output, and pressure drop across the SCR catalyst. A NOx analyzer will be placed upstream of each SCR catalyst for fine tuning the ammonia injection rate and also for use in estimating ammonia slip.

- *Auxiliary Boiler*

The auxiliary boiler will be used to provide steam to both assist the combined cycle plant in reaching its base load quickly, and reduce the start up time. The boiler will be equipped with John Zink/Coen Rapid Mix Low NOx burners and an SCR system to reduce NOx emissions to 5 ppm and CO emissions to 50 ppm @ 3% O2, 1 hour average. Steam from the boiler will not be used to generate any electrical power.

Start up operation
Steam produced in the boiler will be used for steam turbine gland sealing, which is required to initiate a vacuum in the condenser. This would normally require a regulated temperature ramp rate and hence a slower start up for the combustion turbine. However, with the gland seals preheated, the combustion turbine is allowed to ramp more quickly to its target production rate, which in turn results in the heating of the control catalysts quicker, and achieving BACT emission levels sooner.

The boiler may operate for extended periods of time at a hot standby load, which will allow the combined cycle turbines to be maintained in a state of readiness. The boiler's burner is capable of operating at a maximum turndown ratio of 0.25 while still meeting BACT emission level. In other instances, the boiler may be started (cold, warm, or hot) just prior to the turbines coming online. In those cases, the boiler will need from 25 minutes (hot start) to 170 minutes (cold start) to meet its BACT emission levels.

Table 2.11 Auxiliary Boiler Data

Specification	
Boiler Manufacturer	Rentech
Model	D-Type
Boiler Type	Water Tube
Fuel Type	Natural gas
Maximum Fuel Consumption	67,619 ft3/hr(1)
Maximum Exhaust Flow	723,540 ft3/hr(2)
Maximum Heat Input	71 mmbtu/hr
NOx Control	Low NOx Burner/FGR/SCR
Number of Burners	1 per boiler

Burner Manufacturer/Model	JZHC/Coen RMB
Outlet NOx	5 ppm @ 3% O2 1 hour average
Oulet CO	50 ppm @ 3% O2 1 hour average

(1) Based on 1050 btu/cf natural gas
(2)Based on an F factor of 8710 cf/mmbtu corrected to 3% O2

Table 2.11 Auxiliary Boiler SCR Catalyst Data

Specification	
Manufacturer	B&W
Catalyst Type	Vanadium
Catalyst Volume	46 ft^3
Catalyst Area	28 ft^2
Space Velocity	15,729 hr^{-1}
Area Velocity	25,841 ft/hr
Ammonia Slip	5 ppm @ 3% O2 1 hour average
Outlet NOx	5 ppm @ 3% O2 1 hour average
Emissions Guarantee	3 years
Maximum operating temperature	628°F

Space and area velocities based on an exhaust flow rate of 723,540 scf/hr

- *Exhaust Stack*

The boiler exhaust will vent to a 3 foot diameter 80 foot tall stack. The stack will contain sampling ports for exhaust gas testing.

Table 2.12 Auxiliary Boiler Stack Data

Specification	
Stack Diameter	3 feet
Stack Height	80 feet
Stack Area	7.07 ft^2
Exhaust gas temperature	318 deg F
Exhaust gas velocity	4,170 feet/min

- *Ammonia Storage Tanks*

Two new tanks will store 19% aqueous ammonia solution for use in the turbines' and auxiliary boiler SCRs. A 35,000 gallon tank will serve the combined cycle turbines and the boiler. A 15,000 gallon tank will serve the simple cycle turbines. Both tanks will be horizontal pressure vessels with PRVs set at 50 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.

Estimated maximum aqueous ammonia use is about 32 gallons per hour for each combined cycle turbine (240 lbs/hr/7.5 lbs/gal). At an assumed capacity factor of 0.75 for the combined cycle plant, approximate annual aqueous ammonia use is 420,480 gallons (32 X 24 X 365 X 0.75 X 2 turbines).

This is about 12 tank turnovers per year (about one tank filling every 4 weeks on average, accounting for the auxiliary boiler SCR use as well).

Estimated maximum hourly aqueous ammonia use is about 24 gallons per hour for each simple cycle turbine (180 lbs/hr/7.5 lbs/gal), At an assumed capacity factor of 0.3 for the simple cycle plant, approximate annual aqueous ammonia use is 126,144 gallons (24 X 24 X 365 X 0.3 X 2 turbines). This is about 8 tank turnovers per year (about one tank filling every 6 weeks on average).

- *Cooling System*

There are no evaporative water cooling towers associated with this project, the combined cycle turbines will be air cooled. Exhaust steam from the STGs 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. The steam produced in the auxiliary boiler is passed through the HRSGs and steam turbines, and thus is also condensed in the air cooler. The simple cycle turbines do not require steam condensing, since they do not use heat recovery. The only cooling associated with the simple cycle turbines is the use of a fin fan air cooler to cool the water used in the intercooler.

- *Oil Water Separators*

There will be two new oil water separators (OWS) installed to serve the new power system. The OWS will collect potentially oily wastewater from equipment area wash downs and the HRSG feed water pump skid. 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. One OWS will serve the area around the combined cycle plant, and the other will serve the area around the simple cycle plant.

EMISSIONS:

Emissions from the proposed new project will consist of NOx, CO, VOC, PM10, PM2.5, and SOx, plus GHGs and toxics. There are 7 emissions sources: 2 combined cycle turbines, 2 simple cycle turbines, 1 auxiliary boiler, and 2 oil/water separators (emissions from the aqueous ammonia tanks can be assumed to be zero, since they are pressurized tanks).

Emissions from the turbines are calculated for 4 basic operational modes as follows:

1. commissioning – a 1 time event which occurs following installation and just prior to bringing the turbine online for commercial operation
2. start up – occurs each time the turbine is started
3. normal operation
4. shutdown – occurs each time the turbine is shutdown

Table 3.1 - Operational Scenarios for the HBEP Turbines

Scenario	Description
Commissioning	The commissioning operation will require each CT to operate individually as well as simultaneously under part load and full load. The testing will be performed on each CT for the purpose of "tuning in" the turbine combustor and control systems. Emissions are expected to be higher than normal operation. For the combined cycle turbines, the commissioning will take about 996 operating hours per turbine, for the simple cycle turbines, the commissioning is expected to take about 280 hours per turbine.
Startup	For the combined cycle turbines, 3 types of starts are defined – cold, warm , and hot. Cold starts occur after the turbine has been down for 48 hours or more, and the "start" will last about 1 hour (the time to reach proper operating temperature for full DLN, SCR and CO catalyst control). Warm starts occur after the turbine has been down 9 to 48 hours, and will last 30 minutes. Hot starts occur when the turbine has been down less than 9 hours, and will also last 30 minutes. For the simple cycle turbines, start ups last 30 minutes. Applicant anticipates 80 cold, 88 warm, and 332 hot starts per year for each combined cycle turbine, and 350 starts per year for each simple cycle turbine.
Normal Operating	Normal operation is defined as when the turbines are operating at fully controlled levels. Total operation in normal mode is estimated at 6100 hrs per year for each combined cycle turbine, and 1750 hours per year for each simple cycle turbine.
Shutdown	Shutdown is the process of reducing the turbine load and fuel flow to zero. Emissions tend to be higher during shutdowns due to the reduction in control equipment efficiencies as the process progresses.

The auxiliary boiler start ups will also be broken down into cold warm and hot, with the definition of each start as follows - cold starts occur after the boiler has been shutdown for 48 hours or more, warm starts occur after the boiler has been down for 9-48 hours, and hot starts occur after a shutdown of less than 9 hours.

AES has proposed the following operating schedule for the equipment at the facility:

Table 3.2 Combined Cycle Turbines Operating Schedule

Combined Cycle Turbine	Duration/ event	Monthly		Annual	
		Maximum # of Events	Maximum Hours of Operation	Maximum # of Events	Maximum Hours of Operation
Cold Starts	1 hr	15	15	80	80
Warm Starts	30 min	12	6	88	44
Hot Starts	30 min	35	17.5	332	166
Shutdowns	30 min	62	31	500	250
Normal Operation	////////////	///////////	674.5	///////////	6100
		TOTAL	744	///////////	6640

Table 3.3 Simple Cycle Turbines Operating Schedule

Simple Cycle Turbine	Duration /event	Monthly		Annual	
		Maximum # of Events	Maximum Hours of Operation	Maximum # of Events	Maximum Hours of Operation
Starts	30 min	62	31	350	175
Shutdowns	13 min	62	13.4	350	76
Normal Operation	//////////	///////////	700	///////////	1750
		TOTAL	744	///////////	2001

Table 3.4 Auxiliary Boiler Operating Schedule

Auxiliary Boiler	Duration/ event	Monthly		Annual	
		Maximum # of Events	Maximum Hours of Operation	Maximum # of Events	Maximum Hours of Operation
Cold Starts	170 min	2	5.7	24	68
Warm Start	85 min	4	5.7	48	68
Hot Start	25 min	4	1.7	48	20
Normal Operation[1]	//////////	///////////	222.4	///////////	2,573.3
		TOTAL	235.5	///////////	2,729.3

1 based on a heat input of 71 mmbtu/hr. Note that the unit may operate more hours at a lower heat input rate

Detailed emission calculations can be referenced in Appendices A, B, C, D, E, F, and I.

Hourly Emissions

Table 3.5 Hourly Emissions During Normal Operation

Pollutant	Combined Cycle Turbine, lbs/hr	Simple Cycle Turbine, lbs/hr	Auxiliary Boiler, lbs/hr
NOx	16.8	8.2	0.42
CO	~~10.2~~ **7.65**	~~7.9~~ **4.0**	2.83
VOC	5.8	2.3	0.37
PM10	8.5	6.24	0.51
SOx	4.6	1.80	0.14

Table 3.6 Emissions During Start Ups and Shutdowns

Equipment	Event	NOx, lbs/event	CO, lbs/event	VOC, lbs/event
Combined Cycle Turbine	Cold Start	61	325	36
	Warm Start	17	137	25
	Hot Start	17	137	25
	Shutdown	10	133	32
Simple Cycle Turbine	Start	16.6	15.4	2.80
	Shutdown	3.12	28.09	3.06
Auxiliary Boiler	Cold Start	4.22	4.34	1.05
	Warm Start	2.11	2.17	0.52
	Hot Start	0.62	0.64	0.15

Daily Maximum Emissions

Table 3.7 Combined Cycle Turbines Daily Emissions (Maximum)

Pollutant	Operating Scenario	Controlled Daily Emissions 1 Turbine
NOx	1 cold start + 1 hot start + 2 shutdowns + 20.5 hrs normal	442.4
CO	1 cold start + 1 hot start + 2 shutdowns + 20.5 hrs normal	~~937.1~~ **884.8**
VOC	24 hrs normal (no start ups or shutdowns)	243.9
PM10	24 hrs normal (no start ups or shutdowns)	204
SOx	24 hrs normal (no start ups or shutdowns)	110.4
NH3	24 hr normal (no start ups or shutdowns)	317.8

Table 3.8 Simple Cycle Turbines Daily Emissions (Maximum)

Pollutant	Operating Scenario	Controlled Daily Emissions 1 Turbine
NOx	2 starts + 2 shutdowns + 21.57 hrs normal	216.3
CO	2 starts + 2 shutdowns + 21.57 hrs normal	~~259~~ **174.9**
VOC	2 starts + 2 shutdowns + 21.57 hrs normal	61.3
PM10	24 hrs normal (no start ups or shutdowns)	149.8
SOx	24 hrs normal (no start ups or shutdowns)	43.2
NH3	24 hr normal (no start ups or shutdowns)	144

Table 3.9 Auxiliary Boiler Daily Emissions (Maximum)

Pollutant	Operating Scenario	Controlled Daily Emissions
NOx	1 cold start + 21.17 hrs normal	13.1
CO	24 hrs normal (no start ups or shutdowns)	67.9
VOC	24 hrs normal (no start ups or shutdowns)	8.9
PM10	24 hrs normal (no start ups or shutdowns)	12.3
SOx	24 hrs normal (no start ups or shutdowns)	3.4
NH3	24 hr normal (no start ups or shutdowns)	3.8

Monthly and Daily Average Emissions

Table 3.10 Combined Cycle Turbine Monthly Total and 30-Day Average Emissions (Per Turbine)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	15 cold starts+12 warm starts+35 hot starts+62 shutdowns+674.5 hrs normal	13,665.6	455.5
CO	15 cold starts+12 warm starts+35 hot starts+62 shutdowns+674.5 hrs normal	~~26,439.9~~ **24719.9**	~~881.3~~ **824.0**
VOC	15 cold starts+12 warm starts+35 hot starts+62 shutdowns+674.5 hrs normal	7,611.1	253.7
PM10	744 hrs normal (no starts ups or shutdowns)	6,324	210.8
SOx	744 hrs normal (no start ups or shutdowns)	3,422.4	114.1

Table 3.11 Simple Cycle Turbine Monthly Total and 30-Day Average Emissions (Per Turbine)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	62 starts+62 shutdowns + 700 hrs normal	6,959.4	232.0
CO	62 starts+62 shutdowns + 700 hrs normal	~~8,273.4~~ **5,545.0**	~~275.8~~ **184.8**
VOC	62 starts+62 shutdowns + 700 hrs normal	1,972.4	65.7
PM10	744 hrs normal (no start ups or shutdowns)	4,642.6	154.8
SOx	744 hrs normal (no start ups or shutdowns)	1,339.3	44.6

Table 3.12 Auxiliary Boiler Monthly Total and 30-Day Average Emissions

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	2 cold starts +4 warm starts + 4 hot starts + ~~235.5~~ **222.4** hrs normal	112.7	3.8
CO	2 cold starts +4 warm starts + 4 hot starts + ~~235.5~~ **222.4** hrs normal	649.5	21.7
VOC	2 cold starts +4 warm starts + 4 hot starts + ~~235.5~~ **222.4** hrs normal	87.1	2.9
PM10	2 cold starts +4 warm starts + 4 hot starts + ~~235.5~~ **222.4** hrs normal	120.0	4.0
SOx	2 cold starts +4 warm starts + 4 hot starts + ~~235.5~~ **222.4** hrs normal	32.9	1.1

Table 3.13 Facility Monthly Total and 30-Day Average Emissions (Not Including Commissioning)

Equipment	NOx	CO	VOC	PM10	SOx
CCTG 1	13,665.6	~~26,439.9~~ **24,719.9**	7,611.1	6,324	3,422.4
CCTG 2	13,665.6	~~26,439.9~~ **24,719.9**	7,611.1	6,324	3,422.4
SCTG 1	6,959.4	~~8,273.4~~ **5,545.0**	1,972.4	4,642.6	1,339.3
SCTG 2	6,959.4	~~8,273.4~~ **5,545.0**	1,972.4	4,642.6	1,339.3
Aux Boiler	112.7	649.5	87.1	120.0	32.9
OWS 1	0	0	14.3	0	0
OWS 2	0	0	1.8	0	0
Total, lbs/month	41,362.7	~~70,076.1~~ **61,179.3**	19,270.2	22,053.2	9,556.3
30 Day Average, lbs/day	1378.8	~~2335.9~~ **2039.3**	642.3	735.1	318.5

Table 3.14 Facility Monthly Total and 30-Day Average Emissions (Including Commissioning)

The highest NOx, CO, VOC, and SOx monthly emissions occur during CCTG commissioning. Note that PM10 is higher for the non-commissioning month (refer to Appendix C).

Pollutant	CCTG 1 Commissioning, lbs/month	CCTG 2 Commissioning, lbs/month	Total Facility Emissions, lbs/month	30-Day Average Emissions, lbs/day
NOx	22922	22922	45844	1528.1
CO	99076	99076	198152	6605.1
VOC	14109	14109	28218	940.6
PM10	3090	3090	6180	206.0
SOx	5406	5406	10812	360.4

Annual Emissions

Table 3.15 Combined Cycle Turbine Annual Emissions

Pollutant	Operating Scenario	Total Annual Emissions, lbs
NOx	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	119,500
CO	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	~~212,260~~ **196,705**
VOC	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	64,760
PM10	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	56,440
SOx	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	9,960
NH3	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	94,550

Table 3.16 Simple Cycle Turbine Annual Emissions

Pollutant	Operating Scenario	Total Annual Emissions, lbs
NOx	350 starts+350 shutdowns + 1750 hrs normal	21,252
CO	350 starts+350 shutdowns + 1750 hrs normal	~~29,330~~ **22,505**
VOC	350 starts+350 shutdowns + 1750 hrs normal	6,076
PM10	350 starts+350 shutdowns + 1750 hrs normal	12,485
SOx	350 starts+350 shutdowns + 1750 hrs normal	1,201
NH3	350 starts+350 shutdowns + 1750 hrs normal	10,500

Table 3.17 Auxiliary Boiler Annual Emissions

Pollutant	Operating Scenario	Total Annual Emissions, lbs
NOx	24 cold starts+48 warm starts + 48 hot starts + 2573.3 hrs normal	1,313
CO	24 cold starts+48 warm starts + 48 hot starts + 2573.3 hrs normal	7,522
VOC	24 cold starts+48 warm starts + 48 hot starts + 2573.3 hrs normal	1,010
PM10	24 cold starts+48 warm starts + 48 hot starts + 2573.3 hrs normal	1,392
SOx	24 cold starts+48 warm starts + 48 hot starts + 2573.3 hrs normal	382
NH3	24 cold starts+48 warm starts + 48 hot starts + 2573.3 hrs normal	412

Table 3.18 Facility Annual Total Emissions (Not Including Commissioning)

Equipment	NOx	CO	VOC	PM10	SOx	NH3
CCTG 1	119,500	~~212,260~~ **196,705**	64,760	56,440	9,960	94,550
CCTG 2	119,500	~~212,260~~ **196,705**	64,760	56,440	9,960	94,550
SCTG 1	21,252	~~29,330~~ **22,505**	6,076	12,485	1201	10,500
SCTG 2	21,252	~~29,330~~ **22,505**	6,076	12,485	1201	10,500
Aux Boiler	1,313	7,522	1,010	1,392	382	412
OWS 1	0	0	171	0	0	0
OWS 2	0	0	22	0	0	0
Total, lbs/yr	282,817	~~490,702~~ **455,942**	142,875	139,242	22,704	210,512

Table 3.19 Facility Annual Total Emissions (Including Commissioning)

The highest NOx, CO, VOC, and SOx annual emissions occur during CCTG commissioning (refer to Appendix C).

Operating Mode	Hours	Emissions, lbs			
		NOx	CO	VOC	SOx
Commissioning CCTG 1	996	27,593	101,326	14,681	4,843
Commissioning CCTG 2	996	27,593	101,326	14,681	4,843
Post Commissioning Operation CCTG 1	6640	119,500	~~212,260~~ **196,705**	64,760	9,960
Post Commissioning Operation CCTG 2	6640	119,500	~~212,260~~ **196,705**	64,760	9,960
Auxiliary Boiler	2573.3	1,313	7,522	1,010	382
	TOTAL EMISSIONS	295,499	~~634,694~~ **603,584**	159,892	29,988

The highest PM10 annual emissions occur during SCTG commissioning (refer to Appendix C).

Operating Mode	Hours	
		PM10
Commissioning SCTG 1	280	1,747
Commissioning SCTG 2	280	1,747
Post Commissioning Operation SCTG 1	2001	12,484.5
Post Commissioning Operation SCTG 2	2001	12,484.5
CCTG 1	6640	56,440
CCTG 2	6640	56,440
Auxiliary Boiler	2573.3	1,392
	TOTAL EMISSIONS	142,735

Toxic Emissions

Table 3.20 Combined Cycle Turbine Toxic Emissions

Pollutant	Maximum Hourly Emission Rate, lbs/hr		Annual Emissions 1 Turbine, lbs/yr
Ammonia	15.5		94550
1,3 Butadiene	9.48E-04		6.30
Acetaldehyde	3.89E-01		2581.56
Acrolein	7.97E-03		52.92
Benzene	7.19E-03		47.76
Ethyl Benzene	7.04E-02		467.55
Formaldehyde	7.93E-01		5263.51
Naphthalene	2.87E-03		19.07
PAH	1.98E-03		13.17
Propylene Oxide	6.39E-02		424.52
Toluene	2.87E-01		1907.49
Xylene	1.41E-01		936.53
	Total	Lbs/yr	106,270.4
		Tons/yr	53.1

Table 3.21 Simple Cycle Turbine Toxic Emissions

Pollutant	Maximum Hourly Emission Rate, lbs/hr		Annual Emissions 1 Turbine, lbs/yr
Ammonia	6.0		10500
1,3 Butadiene	3.73E-04		0.75
Acetaldehyde	1.53E-01		306.18
Acrolein	3.14E-03		6.28
Benzene	2.83E-03		5.66
Ethyl Benzene	2.77E-02		55.45
Formaldehyde	3.12E-01		624.27
Naphthalene	1.13E-03		2.26
PAH	7.80E-04		1.56
Propylene Oxide	2.52E-02		50.35
Toluene	1.13E-01		226.23
Xylene	5.55E-02		111.08
	Total	Lbs/yr	11890.1
		Tons/yr	5.95

Table 3.22 Auxiliary Boiler Toxic Emissions

Pollutant	Maximum Hourly Emission Rate, lbs/hr		Annual Emissions, lbs/yr
Ammonia	0.16		411.7
Benzene	4.06E-04		1.04
Formaldehyde	8.61E-04		2.21
PAH	7.00E-06		0.02
Naphthalene	2.10E-05		0.05
Acetaldehyde	2.17E-04		0.56
Acrolein	1.89E-04		0.49
Toluene	1.86E-03		4.77
Xylene	1.38E-03		3.55
Ethyl Benzene	4.83E-04		1.24
Hexane	3.22E-04		0.83
Propylene	3.71E-02		95.40
	Total	Lbs/yr	521.86
		Tons/yr	0.26

GHG Emissions

Table 3.23 Combined Cycle Turbine GHG Emissions

GHG	Hourly Tons Per Turbine	Annual Tons Per Turbine	Annual Tons 2 Turbines
CO2	132.9	873,034.6	1,746,069.1
CH4	2.51E-03	16.45	32.9
N2O	2.51E-04	1.65	3.29
Total Mass	132.9	873,052.7	1,746,105.3
CO2e	133.1	873,937.6	1,747,872.5

Table 3.24 Simple Cycle Turbine GHG Emissions

GHG	Hourly Tons Per Turbine	Annual Tons Per Turbine	Annual Tons 2 Turbines
CO2	51.8	103,575.5	207,151.1
CH4	9.75E-04	1.96	3.91
N2O	9.75E-05	0.20	0.40
Total Mass	51.8	103,577.7	207,155.4
CO2e	51.9	103,684.1	207,368.1

Table 3.25 Auxiliary Boiler GHG Emissions

GHG	Emissions	
	Lbs/hr	tons/yr
CO2	~~5067.0~~ **8,306.8**	11,065.31
CH4	~~9.58E-02~~ **0.16**	0.21
N2O	~~9.58E-03~~ **0.02**	0.02
Total Mass	~~5,066.83~~ **8,307.0**	11,065.56
CO2e	~~5,071.90~~ **8,315.4**	11,075.93

Table 3.26 Circuit Breaker GHG Emissions

AEC Electric Breakers	Total SF6 (lbs)	Annual SF6 Emissions (lbs/yr)
1200A 230kV	230	1.15
1200A 230kV	230	1.15
1200A 230kV	230	1.15
3000A 230kV	230	1.15
10000A 18kV	25	0.125
10000A 18kV	25	0.125
10000A 18kV	25	0.125
2000A 230kV	216	1.08
GCB 13.8kV	24	0.12
GCB 13.8kV	24	0.12
	TOTAL	6.3 lbs/yr
	CO2e	71.8 tons/yr

EVALUATION:

RULE 212-Standards for Approving Permits

This project is subject to Rule 212 public notice requirements because the daily maximum VOC, CO, NOx, and PM10 emissions from the project will all exceed the emissions thresholds specified in subdivision (g) of this rule. The facility is not located within 1000 feet of a school (the closest school is Edison High located approximately 0.6 miles north-east of the site). The District will prepare the public notice and it will contain sufficient information to fully describe the project.

In accordance with subdivision (d) of this rule, the applicant will be required to distribute the public notice to each address within ¼ mile radius of the project.

Subdivision (g) requires that the public notification and comment process include all applicable provisions of 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10. The minimum requirements specified in the above documents are included in paragraphs (g)(1), (g)(2), and (g)(3).

In accordance with paragraph (g)(1) of this rule, the District will make the following information available for public inspection at the Huntington Beach Public Library located at 7111 Talbert Ave, Huntington Beach 92648, during the 30-day comment period: public notice, project information submitted by the applicant, and the District's permit to construct evaluation.

In accordance with paragraph (g)(2) of this rule, the public notice will be published in a newspaper which serves the area that will be impacted by the project.

In accordance with paragraph (g)(3) of this rule, the public notice will be mailed to the following persons: the applicant, the Region IX EPA administrator, the ARB, the chief executives of the city and county where the project will be located, the regional land use planning agency, and the state and federal land managers whose lands may be affected by the emissions from the proposed project.

SCAQMD also periodically includes a notice in the *SCAQMDAdvisor* advising interested parties on how to receive notification of PSD projects. The latest notice was included in the March 2016 issue.

After the public notice is published, there will be a 30-day period for submittal of public comments.

RULE 218 – Continuous Emission Monitoring

In order to insure the turbines meet the CO BACT limit as specified in the permit, a CO CEMS will be required by permit condition. The CO CEMS must be certified in accordance with Rule 218. The rule requires submittal of an "Application for CEMS" for approval. Once approved, CEMS data must be recorded and records of the data must be maintained on site for at least 2 years. Additionally, every 6 months a summary of the CEMS data must be submitted to AQMD. Any CEMS breakdowns must also be reported. Compliance with this rule is expected. The auxiliary boiler will not be required to have a CO CEMS.

RULE 401 – Visible Emissions

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

RULE 402 - Nuisance

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

RULE 403 – Fugitive Dust

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The applicant will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. They have proposed the following measures:

Watering unpaved roads and disturbed areas
Limiting onsite vehicle speeds to 10 mph and posting the speed limit
Frequent watering during periods of high winds when excavation/grading is occurring
Sweeping onsite paved roads and entrance roads on an as-needed basis
Replacing ground cover in disturbed areas as soon as practical
Covering truck loads when hauling materials that could be entrained during transit
Applying dust suppressants or covers to soil stockpiles and disturbed areas when inactive for more than 2 weeks

In addition, the applicant will need to implement all Best Available Control Measures listed in Table 1 of the rule.

The installation and operation of the turbines and associated equipment is expected to comply with this rule.

Rule 404 – Particulate Matter Concentration
This rule applies to the auxiliary boiler. Turbines are exempt under paragraph (c) of the rule. The rule limits the PM concentration based on the stack flow. At maximum firing rate, the boiler stack flow is estimated to be:

71 mmbtu/hr X [8710 cf/mmbtu(20.9/20.9-3)] = 723,540 cf/hr, or 12,059 cfm

At this exhaust flow rate, maximum allowable PM concentration is 0.073 gr/scf.

Estimated PM concentration

(0.51 lbs/hr *7000 gr/lb)/ 723,540 cf/hr = 0.0049 gr/scf

Compliance is expected.

RULE 407 – Liquid and Gaseous Air Contaminants
This rule limits CO emissions to 2000 ppmv. The SO2 portion of the rule does not apply as the natural gas fired in the turbines and auxiliary boiler will be subject to the sulfur limit in Rule 431.1. The CO emissions from the combined cycle turbines will be controlled by an oxidation catalyst to ~~2.0~~ **1.5** ppmvd at 15% O2. The CO emissions from the simple cycle turbines will be controlled by an oxidation catalyst to ~~4.0~~ **2.0** ppmvd at 15% O2, and the CO emissions from the boiler will be maintained at 50 ppm at 3% O2. Therefore, compliance with this rule is expected.

RULE 409 – Combustion Contaminants
This rule restricts the discharge of contaminants from the combustion of fuel to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes. The turbines and boiler are expected to meet this limit at the maximum firing load based on the calculations shown below. Compliance will be verified through the initial performance test.

Grain Loading = [(A x B)/(C x D)] x 7000 gr/lb

where:

A = PM10 emission rate during normal operation
B = Rule specified percent of CO2 in the exhaust (12%)
C = Percent of CO2 in the exhaust (approx. 4.29% for natural gas)
D = Stack exhaust flow rate

Combined Cycle Turbines

Grain Loading = $\dfrac{8.5 \text{ lbs/hr} \times [(7000 \text{ grains/lb}) \times (12/4.29)]}{70.1\text{E}+06 \text{ scf/hr}}$

= $\boxed{0.002 \text{ grains/scf}}$

Simple Cycle Turbines
Grain Loading = $\dfrac{6.24 \text{ lbs/hr} \times [(7000 \text{ grains/lb}) \times (12/4.29)]}{27.3\text{E}+06 \text{ scf/hr}}$

= $\boxed{0.004 \text{ grains/scf}}$

Auxiliary Boiler
Grain Loading = $\dfrac{0.51 \text{ lbs/hr} \times [(7000 \text{ grains/lb}) \times (12/4.29)]}{0.724\text{E}+06 \text{ scf/hr}}$

= $\boxed{0.014 \text{ grains/scf}}$

RULE 431.1 – Sulfur Content of Gaseous Fuels

The natural gas supplied to the turbines and auxiliary boiler is expected to comply with the 16 ppmv sulfur limit (calculated as H_2S) specified in this rule. Commercial grade natural gas has an average sulfur content of about 4ppm. The long term (annual) SOx emissions from the turbines are based on 4 ppm or about 0.25 gr/100 cf concentration. The short term (hourly, daily, and monthly) SOx emissions from the turbines are based on 12 ppm or about 0.75 gr/100 cf concentration. A condition will be placed on the permit to require that the sulfur content is measured and recorded to insure compliance. The applicant will also comply with reporting and record keeping requirements as outlined in subdivision (e) of this rule.

RULE 475 – Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from the combined cycle turbines are estimated at 8.5 lbs/hr, and 0.0026 gr/scf at maximum firing load, and PM10 emissions for the simple cycle turbines are estimated at 6.24 lbs/hr and 0.0049 gr/scf at maximum firing load (see calculations below). Therefore, compliance is expected. Compliance will be verified through the initial performance test as well as ongoing periodic testing.

$$Stack\ Exhaust\ Flow\left(\frac{scf}{hr}\right) = F_d\ x\ \frac{20.9}{(20.9 - \%O_2)}\ x\ TFD$$

where:
Fd: Dry F factor for fuel type, 8710 dscf/MMBtu
O2: Rule specific dry oxygen content in the effluent stream, 3%
TFD: Total fired duty measured at HHV

$$Combustion\ Particulate\left(\frac{grain}{scf}\right) = \frac{PM_{10},\ lb/hr}{Stack\ Exhaust\ Flow,\ scf/hr}\ x\ 7000\ \frac{gr}{lb}$$

Combined Cycle Turbines
Stack flow = 8710(20.9/17.9)*2273 = 23.1 mmscf/hr

Combustion particulate = (8.5/23.1E+06)*7000 = $\boxed{0.0026\ gr/scf}$

Simple Cycle Turbines
Stack flow = 8710(20.9/17.9)*885 = 9.0 mmscf/hr

Combustion particulate = (6.24/9.0E+06)*7000 = $\boxed{0.0049\ gr/scf}$

RULE 1134 – Emissions of NOx from Gas Turbines
This rule applies to gas turbines, 0.3 MW and larger, installed on or before August 4, 1989. Therefore, as a new installation, the proposed HBEP turbines are not subject to this rule.

RULE 1135 – Emissions of NOx from Electric Power Generating Systems
This rule applies to the electric power generating systems of several of the major utility companies in the basin, including SCE and their successors. The plants which are included in the RECLAIM program are no longer subject to the requirements of this rule.

Rule 1146 – NOx from Boilers
This rule applies to boilers over 5 mmbtu/hr. Emission limits are 9 ppm NOx for gas firing, and 400 ppm CO.

The auxiliary boiler is equipped with a Low NOX burner, incorporating FGR, and manufacturer guaranteed emission rates of NOx ≤ 9 ppm and CO ≤ 50 ppm. The boiler will also be equipped with an SCR which will further reduce NOx to 5 ppm. Under the rule, the unit must be tested periodically using a portable analyzer method every 750 operating hours, or monthly, whichever occurs later. If 3 consecutive tests show compliance without adjustment to the oxygen sensor set points, then the periodic tests are only required every 2,000 hours or quarterly. Furthermore, for boilers >10 mmbtu/hr, a stack test using the reference methods is required every 3 years. Since the HB facility is subject to NOx RECLAIM, only the CO limits are applicable to the boiler, and the periodic monitoring and stack testing is only required for CO. Compliance is expected.

REGULATION XIII/Rule 2005 – New Source Review

The new turbines, auxiliary boiler, ammonia tanks, and oil/water separators are subject to NSR. All equipment must be installed with BACT. In addition, some of the emissions are subject to modeling and offsets. The installation of all the new equipment at the Huntington Beach plant is considered a major modification to an existing major source. Therefore, the additional requirements for major sources are applicable.

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

In order to qualify for the exemption, AES HB is proposing to shutdown 3 boilers in conjunction with the construction of the new HBEP. The 3 boilers include Boilers 1 and 2 at the Huntington Beach site, as well as Boiler 7 at AES' Redondo Beach Generating Facility, located at 1100 N. Harbor Dr, Redondo Beach, CA 90277. The capacity of the boilers being shutdown is shown in the table below:

Table 4.1 Capacity of Units Being Shutdown

Unit	Capacity, MW
Boiler 1, HB	215
Boiler 2, HB	215
Boiler 7, RB	480
Total Shutdown Capacity	910

The shutdown capacity is based on the description of the units as listed in the current SCAQMD permits.

The capacity of the new units is summarized below:

Table 4.2 Capacity of New Units

Unit	Total Gross Capacity as Permitted, MW
CCTG 1	346.9
CCTG 2	346.9
SCTG 1	100.8
SCTG 2	100.8
Total New Capacity	895.5

MW rating for the CCTGs at 32° F and includes ½ the rating of the steam turbine

The capacity of the units being shutdown is sufficient to cover the capacity of the new units, therefore, the new units qualify for the offset and modeling exemption. The actual emissions from the 2 units being shutdown at the Huntington Beach facility (Boiler 1 and 2) are shown in Appendix N for reference.

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

- Offsets (for Non-Exempt Equipment)

The emissions from the auxiliary boiler and oil/water separators do not fall under the utility boiler replacement exemption. Offsets for non-RECLAIM pollutants VOC and PM10 for this equipment will be provided in the form of ERCs (offsets for CO emissions are not required).

Table 4.3 Offsets Required for Equipment Not Exempt Under the Steam Boiler Replacement

Equipment	VOC			PM10		
	Lbs/month	Lbs/day	Offsets Required[1]	Lbs/month	Lbs/day	Offsets Required[1]
Auxiliary Boiler	87.1	2.9	4	120.0	4.0	5
OWS 1	14.3	0.48	1	0	0	0
OWS 2	1.8	0.06	0	0	0	0

1 includes an offset factor of 1.2

Under Rule 2005, RTCs to cover the expected emissions of NOx are required to be held for the first compliance year. Additionally, since the NOx PTE after the first year is less than the facility's initial allocation, the facility is not required to hold NOx RTCs for subsequent years. The Huntington Beach facility is also in the SOx RECLAIM program. Therefore, SOx RTCs are required to be held to cover the first year of operation. Additionally, because the facility opted into SOx RECLAIM after 1994, there is no initial allocation. For this reason, SOx RTCs are required to be held for each compliance year after the first year of operation [paragraph (f)(1)]. RTC requirements are shown in Appendix S.

- BACT

BACT is required for all criteria pollutants and ammonia. For major sources, BACT is determined at the time the permit is issued, and is the Lowest Achievable Emission Rate (LAER), which has been Achieved in Practice. Based on recently issued permits, (including LADWP Scattergood, Oakley Generating Station, El Segundo Power, Canyon Power, **Mariposa Power, Marsh Landing Generating Station, Warren County Power**, and El Cajon Energy, see Appendix T) SCAQMD has determined that BACT for the gas turbines is as follows:

Table 4.4 Combined Cycle Turbine Required BACT

NOx	CO	VOC	PM_{10}	SOx	NH3
2.0 ppmvd @ 15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	Natural gas fuel	Natural gas fuel with fuel sulfur content of no more than 1 grain/100 scf (about 16 ppm)	5.0 ppmvd @ 15% O2, 1 hour average

The applicant is proposing the following emission levels for the combined cycle turbines. The emission levels of NOx, CO, VOC, and NH3 in the table are manufacturer guaranteed emissions under normal operating conditions.

TABLE 4.5 – Proposed Control Levels for the HBEP Combined Cycle Turbines

NOX	CO	VOC	PM10	SOX	NH3
2.0 ppmvd @ 15% O2, 1 hour average	~~2.0~~ **1.5** ppmvd @ 15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	Exclusive use of natural gas fuel, PM10 emissions of 8.5 lbs/hr	Exclusive use of natural gas fuel*	5.0 ppmdv @ 15% O2, 1 hour average

**Natural gas provided by the Gas Company is limited to 16 ppm in the South Coast by Rule 431.1. Generally, the actual sulfur content is about 4 ppm (4 ppm corresponds to 0.25 gr/100 scf)*

Table 4.6 Simple Cycle Turbine Required BACT

NOx	CO	VOC	PM_{10}	SOx	NH3
2.5 ppmvd @ 15% O2, 1 hour average	~~4.0~~ **2.0** ppmvd @ 15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	Natural gas fuel	Natural gas fuel with fuel sulfur content of no more than 1 grain/100 scf (about 16 ppm)	5.0 ppmdv @ 15% O2, 1 hour average

The applicant is proposing the following emission levels for the simple cycle turbines. The emission levels of NOx, CO, VOC, and NH3 in the table are manufacturer guaranteed emissions under normal operating conditions.

TABLE 4.7 – Proposed Control Levels for the HBEP Simple Cycle Turbines

NOX	CO	VOC	PM10	SOX	NH3
2.5 ppmvd @ 15% O2, 1 hour average	~~4.0~~ **2.0** ppmvd @15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	Exclusive use of natural gas fuel, PM10 emissions of 6.24 lbs/hr	Exclusive use of natural gas fuel*	5.0 ppmvd @ 15% O2, 1 hour average

**Natural gas provided by the Gas Company is limited to 16 ppm in the South Coast by Rule 431.1. Generally, the actual sulfur content is about 4 ppm (4 ppm corresponds to 0.25 gr/100 scf)*

Table 4.8 Auxiliary Boiler Required BACT

NOx	CO	VOC	PM_{10}	SOx	NH3
5.0 ppmdv @ 3% O2, 1 hour average	100 ppmdv @ 3% O2, (water tube boilers)	none	Natural gas fuel	Natural gas fuel	5.0 ppmdv @ 3% O2

The applicant is proposing the following emission levels for the auxiliary boiler. The emission levels of NOx, CO, and NH3 in the table are manufacturer guaranteed emissions under normal operating conditions.

TABLE 4.9 – Proposed Control Levels for the Auxiliary Boiler

NOX	CO	VOC	PM10	SOX	NH3
5.0 ppmvd @ 3% O2, 1 hour average	50.0 ppmvd @ 3% O2, 1 hour average	none	Exclusive use of natural gas fuel	Exclusive use of natural gas fuel	5.0 ppmdv @ 3% O2, 1 hour average

BACT for the ammonia tank is the use of a pressure vessel equipped with a p/v valve.

- Modeling

The applicant conducted a modeling analysis to determine NO2 impacts from the new turbines as required by Rule 2005. And although non-RECLAIM pollutant emissions from the turbines are exempt from modeling pursuant to the Electric Utility Steam Boiler Replacement exemption, a modeling analysis was performed for CO, SO2, and PM10 for purposes of the CEC's review of project impacts. Additionally, the auxiliary boiler emissions, which are not exempt from modeling under SCAQMD rules, were included along with the turbines in the modeling performed for the project.

Modeling evaluations were performed using the American Meteorological Society/USEPA AERMOD (version 15181) model and representative meteorological data from the John Wayne Airport meteorological station. Modeling analysis was performed for turbine startups, normal turbine operation, turbine commissioning operations, along with the auxiliary boiler emissions. A discussion of the modeling procedure and the inputs used in the modeling are shown in Appendix H.

The air basin where the facility is located is in attainment for NO2, CO, and SO2. PM10 was designated as a federal attainment pollutant in the SCAB on July 26, 2013, however it remains in non-attainment status at the state level and will therefore be evaluated as non-attainment. The compliance determination for NO2, CO, and SO2 is a comparison of the project impact plus the background concentration to show that it does not exceed the AAQS. For PM10, the project impact should not exceed the Significant Increment. The results of the model show that the project will not cause a violation, or make significantly worse an existing violation, of any state or national ambient air quality standard. Model results are summarized in the tables below.

Table 4.10 Model Results – Start Up/Shutdown and Normal Operation

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2[1]	1-hour	95	142	237	//////////	339
	1-hour Federal	27.8	98.2	126	188	//////////
	Annual	0.59	21.8	22.4	100	57
CO[2]	1-hour	631	3,435	4,066	40,000	23,000
	8-hour	149	2,519	2,668	10,000	10,000
SO2	1-hour	5.76	23.1	28.9	//////////	655
	1-hour Federal	5.4	23.1	28.5	196	//////////
	3-hour	5.01	23.1	28.2	1,300	//////////
	24-hour	1.66	5.2	6.86	365	105
PM10	24-hour	4.7	51.0	55.7	150	50
	Annual	0.6	19.3	19.9	//////////	20
PM2.5	24-hour Federal	4.7	21.3	26	35	//////////
	Annual	0.6	8.6	9.2	12	12

The model includes emissions from all 5 stacks combined (2 CCTG, 2 SCTG, and the aux boiler)

[1]The maximum 1 hour and annual NO2 concentrations include ambient NO2 ratios of 0.80 and 0.75 respectively.

[2] ***The simple cycle turbines normal operations were modeled at an emission concentration of 4.0 ppm, however during review of the PDOC, CO BACT was determined to be 2.0 ppm for these units. The modeling was not re-run however re-modeled results are expected to be less than what is presented in the table.***

Table 4.11 Model Results, CCTG Commissioning

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2	1-hour	169	142	311	//////////	339
	Annual	0.66	21.8	22.5	100	57
CO	1-hour	4,341	3,435	7,776	40,000	23,000
	8-hour	3,000	2,519	5,519	10,000	10,000
PM10	Annual	0.57	19.3	19.9	//////////	20
PM2.5	Annual	0.57	8.6	9.2	12	12

Table 4.12 Model Results, SCTG Commissioning

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2	1-hour	79.1	142	221	//////////	339
	Annual	0.50	21.8	22.3	100	57
CO	1-hour	527	3,435	3,962	40,000	23,000
	8-hour	131	2,519	2,650	10,000	10,000
PM10	Annual	0.52	19.3	19.8	//////////	20
PM2.5	Annual	0.52	8.6	9.1	12	12

The modeling was reviewed by SCAQMD modeling staff and deemed acceptable. Refer to the memo from Ian MacMillan to Andrew Lee dated May 18, 2016.

Other requirements of Rule 1303:

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

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

Alternative Analysis. The project is subject to the California Energy Commission licensing procedure. Under this procedure, a full analysis of the proposal is conducted, including project alternatives. The alternative project analysis was conducted under the previous HBEP AFC in 2012 **(Commission Decision in 2014)**. **The Preliminary Staff Assessment for the amended HBEP concluded that the alternatives previously found to be infeasible remain infeasible, and there is no information indicating any new alternatives should be analyzed.**
(*http://docketpublic.energy.ca.gov/PublicDocuments/12-AFC-02C/TN211973_20160624T152748_Preliminary_Staff_Assessment.pdf*)

The following alternative generating technologies were considered:

- Conventional Boiler and Steam Turbine

Rejected because of the low efficiency and large space requirements

- Kalina Combined-Cycle

Rejected because the technology is still in development stage

- Internal Combustion Engine

Rejected because of higher emissions profile and smaller output than proposed turbine plant

The following fuel technology alternatives were considered:

- Geothermal and Hydroelectric

Rejected because there are no geothermal or hydroelectric resources near the plant site

- Biomass

Rejected because there are not enough locally available sources of biomass

- Wind

Rejected because the site does not experience sufficient wind resources

- Solar

Rejected because of space limitations and lack of sufficient solar resources

AES also considered wet cooling using either potable or recycled water, or seawater, as an alternative to the proposed dry cooling of the turbines. This was rejected because in the case of potable water, its use for power plant cooling purposes is discouraged by SWRCB and the CEC. In the case of recycled water, an additional pipeline and treatment facility would need to be constructed to supply enough water at the required level of treatment to serve the plant. The seawater option was rejected because of the environmental impacts of a seawater intake pipe, and cost considerations.

An alternative to the proposed site of the power plant was determined to be not necessary because PRC 25540.6 [b] states that if the commission finds 'that the project has a strong relationship to the existing industrial site' …..'it is therefore reasonable not to analyze alternatives sites for the project'.

Protection of Visibility. Net Increase in emissions from the proposed project exceed the 15 tons per year PM_{10} and 40 tons per year NOx thresholds, but the site is not within the specified distance of any Class I areas. Distances to the Class I areas are summarized below:

Table 4.13 Distances to Class I Areas

Federal Class I Area	Threshold Distance (km)	Distance from the HBEP (km)
Cucamonga Wilderness	28	69
San Gabriel Wilderness	29	69.9
San Gorgonio Wilderness	32	107.6
San Jacinto Wilderness	28	114.2
Agua Tibia Wilderness	28	90.6
Joshua Tree NP	29	145.4

A visibility analysis was conducted under the PSD regulation.

Statewide Compliance. The facility submitted a statement dated October 12, 2015 from Stephen O'Kane, a corporate officer, certifying that all AES's stationary sources are currently in compliance with applicable state and federal environmental regulations. **Prior to issuing the Permit to Construct, SCAQMD will confirm that the compliance status of AES has not changed.**

Rule 1304.1 – Electrical Generating Facility Fee for Use of Offset Exemption

The project will utilize the offset exemption of Rule 1304(a)(2) for PM10 and VOC, and is therefore subject to a fee under this rule. The facility has opted to pay an annual fee. The formula for calculating this fee is as follows:

$$[(R_{iA1}\times 100/MW)+ R_{iA2}\times(MW-100)/MW]\times OF_i \times PTErep_i \times[(C_{rep}-C_{2YRAvgExisting})/C_{rep}]$$

Where:

Fi	=	Offset fee for pollutant (i)
RiA1	=	Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually (Table A1 of the rule)
RiA2	=	Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually (Table A2 of the rule)
MW	=	MW of new replacement units
OFi	=	Offset factor pursuant to Rule 1315(c)(2) for extreme non-attainment pollutants and their precursors (Tables A1 and A2 of the rule)
PTErepi	=	permitted potential to emit of new replacement units for pollutant (i), in pounds per day (maximum permitted monthly emissions ÷ 30 days).
Crep	=	maximum permitted annual megawatt-hour (MWh) generation of the new replacement units (maximum rated capacity (MW) X maximum permitted annual operating hours)
C2yravgexisting	=	maximum annual megawatt-hour (MWh) generation of the existing units to be replaced using the last 24 month period immediately prior to issuance of the permit to construct.

The facility will be required to demonstrate compliance with the specific requirements of this rule prior to the issuance of the Permits to Construct for the HBEP Project. The following calculation provides an estimate of the approximate fee that will be required.

The following factors are used in the equation:

Factor	PM10	VOC
PTErep	731 lbs/day	639 lbs/day
Ri1A	$997/lb/day	$47/lb/day

Ri2A	$3,986/lb/day	$185/lb/day
OFi	1.0	1.2
MW	895.5 MW	895.5 MW
Crep	4,584,980 MWh	4,584,980 MWh
C2yr	840,400 MW	840,400 MW

Notes:
PTErep is calculated as follows: PM10 – 210.8 lbs/day*2 (CCTG) + 154.8 lbs/day*2 (SCTG) = 731 lbs/day, VOC – 253.7 lbs/day*2 (CCTG) + 65.7 lbs/day*2 (SCTG) = 639 lbs/day
Crep is calculated as follows: 693.8 MW * 6,100 hrs + 201.6 MW * 1750 hrs = 4,584,980 MWh (no starts or shutdowns included)
C2yr is taken from Appendix Q

PM10

F_{PM10} = $[(997\times100/895.5) + 3986\times(895.5-100)/895.5]\times 1.0 \times731 \times[(4584980-840400)/4584980]$

F_{PM10} = [(111.33)+(3540.89)]X(1.0)X(731)X(0.8167)

F_{PM10} = $2,180,403.46/yr (to be adjust by CPI from 2013 dollars)

VOC

F_{VOC} = $[(47\times100/895.5) + 185\times(895.5-100)/895.5]\times 1.2 \times639 \times[(4584980-840400)/4584980]$

F_{VOC} = [(5.25)+(164.34)]X(1.2)X(639)X(0.8167)

F_{VOC} = $106,204.98/yr (to be adjust by CPI from 2013 dollars)

Total fee = 2,180,403.46 + 106,204.98 = $2,286,608.96/yr (to be adjust by CPI from 2013 dollars)

The rule allows the facility the option to pay a lump sum fee after the first year.

RULE 1325/~~40CFR 51 Appendix S – Federal~~ PM2.5 New Source Review
Rule 1325 is the New Source Review rule for PM2.5 and its precursors, NOx and SO2. This rule applies to new major polluting facilities, major modifications to existing major polluting facilities, or any modification to an existing facility that would constitute a major polluting facility in and of itself. A major polluting facility is defined as a facility located in a federal non-attainment area which has actual emissions, or a potential to emit of greater than 100 tons per year, of either PM2.5 or its precursors. Note that EPA recently re-classified the South Coast basin as serious non-attainment for PM2.5. This effectively reduces the major source threshold from 100 tons per year to 70 tons per year. ~~However, the reclassification does not take effect until August 14, 2017, or earlier if SCAQMD adopts the revised threshold by amending this rule prior to that date.~~

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

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

A major modification is defined as any physical change or change in the method of operation at a major source which results in a significant emission increase and a significant net emissions increase. If subject to this subpart, the facility is required to comply with the following requirements on a pollutant specific basis:

- Use of LAER
- Offset emissions at the applicable offset ratio
- Certification of compliance with emission limits for all major sources under common control
- Conduct an alternative analysis of the project

~~Since Rule 1325 is not SIP approved at this time, the requirements of NSR for PM2.5 and its precursors must be implemented through Appendix S. Appendix S sets forth EPA's Interpretive Ruling on the preconstruction review requirements for stationary sources.~~

As shown in Appendix O, the existing facility is not a major source for PM2.5 and SO2, but is a major source for NOx. Furthermore, as shown in Appendix O, there will be a significant increase and significant net increase in NOx resulting from the proposed modification (the significant increase threshold is 40 tpy for NOx based on new PTE vs. existing actual). Therefore, the HBEP is considered a major modification to an existing major source for NO2 and is subject to NSR under this rule for NOx only. The project is also considered a major modification for NOx under SCAQMD Rule 2005 and Regulation XVII (PSD), and as such, all of the requirements listed above have been addressed under those rules.

RULE 1401 – New Source Review of Toxic Air Contaminants

This rule requires an analysis of the new permit units' impacts due to the release of air toxics. A Tier 4 Health Risk Assessment was performed using CARB's Hotspots Analysis and Reporting Program (HARP, version 2). Model inputs and results are presented in Appendix H. The results of the model are summarized below:

Table 4.14 Model Results – HRA CCTG (individual unit)

Receptor	Cancer Risk Per Million	Chronic Hazard Index	Acute Hazard Index
Maximum Impact	2.38	0.0060	0.032
MEIR	1.36	0.0035	0.0090
MEIW	0.086	0.0060	0.091
Sensitive receptor	0.74	0.00346	0.032

Table 4.15 Model Results – HRA SCTG (individual unit)

Receptor	Cancer Risk Per Million	Chronic Hazard Index	Acute Hazard Index
Maximum Impact	0.086	0.00022	0.0017
MEIR	0.059	0.00015	0.0012
MEIW	0.003	0.00022	0.0017
Sensitive receptor	0.1	0.00012	0.00070

Table 4.16 Model Results – HRA Auxiliary Boiler

Receptor	Cancer Risk Per Million	Chronic Hazard Index	Acute Hazard Index
Maximum Impact	0.18	0.0005	0.0011
MEIR	0.026	0.00008	0.0003
MEIW	0.004	0.0005	0.001
Sensitive receptor	0.03	0.00008	0.0003

The cancer burden is 0.42 based on a radius of 2.03 km and a population density of 7,000 persons/km.

The results show that the cancer risk for each turbine is less than the rule limit of 10 in one million (for permit units with T-BACT, considered an oxidation catalyst for the turbines), and less than 1 in one million for the auxiliary boiler. Furthermore, the hazard indices are less than 1 for all the turbines and boiler, and the cancer burden is below the threshold of 0.5.

The modeling was reviewed by SCAQMD modeling staff and deemed acceptable. Refer to the memo from Ian MacMillan to Andrew Lee dated May 18, 2016.

REGULATION XVII – Prevention of Significant Deterioration

The South Coast Basin where the project is to be located is in attainment for NO2, SO2, CO, and PM10 emissions. Additionally, beginning on January 2, 2011, Greenhouse Gases (GHGs) are a regulated criteria pollutant under the PSD major source permitting program. Therefore each of these pollutants must be evaluated under PSD for this project.

PSD applies on a pollutant-specific basis to a new major source, a significant increase in emissions from an existing major stationary source, or a modification at a non-major source, if the modification is considered major in and of itself. For any of the 28 listed source categories, the major source threshold is 100 tons per year based on actual emissions or potential to emit. The major source threshold is 250 tons/yr for source categories that are not listed. As a natural gas fired combined/simple cycle power plant, the HBEP falls within the 28 source category definitions, and therefore the applicable threshold is 100 tpy.

If the facility is deemed to be major, Rule 1702 further defines a major modification as a significant emission increase of 40 tpy or more of NO2 or SO2, 15 tpy of PM10, or 100 tons per year or more of CO (determined on a new PTE vs. existing actual basis). The existing equipment at the Huntington Beach Generating Station is a major source for NOx, CO, and GHGs, but not PM10 or SOx. Furthermore, with the addition of the new equipment, there is a significant increase of NO2 and GHG but not CO, and therefore, a PSD review is required for NOx and GHGs. Finally, the addition of the new gas turbines does not constitute a major source in and of itself for PM10 or SOx.

Requirements for a significant emission increase under Rule 1703 include the following:

- Use of BACT [1703(a)(3)(B)]
- Modeling to determine impacts of the project of National and State AAQS and increases over the baseline concentration [1703(a)(3)(C)]
- Analysis of ambient air quality in the impact area [1703(a)(3)(D)]
- Analysis of project impacts on visibility, soil, and vegetation [1703(a)(3)(E)]

BACT is also required for any pollutant for which there is a net emission increase, therefore BACT applies for all pollutants. The BACT determination for NO2, CO, SO2, and PM10 is based on a top-down analysis. This analysis has been performed for power plants of this type multiple times in the recent past, and the facility performed this top-down approach. The technologies considered for each pollutant are summarized in the following table (Appendix T summarizes the emission limits considered in the BACT analysis):

Table 4.14 Control Technologies Evaluated for BACT - Turbines

NOx	CO	VOC	PM10	SOx
Water Injection	Combustion Design	Combustion Design	Combustion Design and Clean Fuel	Combustion Design and Clean Fuel
DLN Combustion	Oxidation Catalyst	Oxidation Catalyst	Electrostatic Precipitators	Wet or Dry Scrubber
XONON™			Baghouse	
SCR				
EMx				
SNCR				

Table 4.15 Control Technologies Evaluated for BACT - Boiler

NOx	CO	VOC	PM10	SOx
Low NOx Burner/FGR	Combustion Design	Combustion Design	Combustion Design and Clean Fuel	Combustion Design and Clean Fuel
SCR				

In its analysis, the facility eliminated electrostatic precipitators and baghouses as technologically infeasible options for PM10 control of the turbines, and also eliminated the wet or dry scrubber option as infeasible for SOx control of the turbines.

The results of the analysis are summarized as follows:

- NO_2 –
  Combined Cycle Turbines
  - ✓ The combined cycle turbines must meet a limit of 2.0 ppmvd, 1-hour average at 15% O_2. The facility has chosen to use DLN combustors and a conventional SCR system for the control of NOx emissions to this level.

  Simple Cycle Turbines
  - ✓ The simple cycle turbines must meet a limit of 2.5 ppmvd, 1-hour average at 15% O_2. The facility has chosen to use DLN combustors and a conventional SCR system for the control of NOx emissions to this level.

  Auxiliary Boiler
  - ✓ The auxiliary boiler must meet a limit of 5.0 ppmvd 1 hour average at 3% O2. The facility has chosen to use a LowNOx burner/FGR and conventional SCR system for the control of NOx emissions to this level.

- SO_2 – The requirement is to use pipeline quality natural gas. The facility is proposing the use of this fuel type exclusively for all combustion equipment.

- CO –
  Combined Cycle Turbines
  - ✓ The combined cycle turbines must meet a limit of 2.0 ppmvd based on 1-hour average at 15% O_2. The facility has chosen to use a conventional oxidation catalyst system for the control of CO emissions ~~this level.~~ **<u>, and has proposed a level of 1.5 ppmvd 1-hour average @ 15% O2.</u>**

  Simple Cycle Turbines
  - ✓ The simple cycle turbines must meet a limit of ~~4.0~~ **<u>2.0</u>** ppmvd based on 1-hour average at 15% O_2. The facility has chosen to use a conventional oxidation catalyst system for the control of CO emissions to this level.

  Auxiliary Boiler
  - ✓ The auxiliary boiler must meet a limit of 50 ppmvd based on 1-hour average at 3% O_2. The facility has chosen to use combustion design for the control of CO emissions to this level.

- PM10 – The requirement is to use pipeline quality natural gas with a sulfur content (calculated as H_2S) less than 1 grain per 100 scf. The facility is proposing the use of this fuel type exclusively for all combustion equipment.

The PSD modeling analysis requires the following steps:

1. Determine whether preconstruction monitoring is required
2. Assessment of significance under PSD
3. Determine Ambient Air Quality Impacts
4. Determine Impacts in Class I Areas, including visibility, soil, and vegetation

The applicant performed modeling which indicated that the maximum 1-hour and 8-hour CO impacts from turbine operations including start ups and shutdowns are 631 ug/m3 and 149 ug/m3 respectively. These results are below the corresponding US EPA CO Class II SILs of 2,000 ug/m3and 500 ug/m3. Therefore, 1-hour and 8-hour CO increment analyses are not required.

The peak annual NO2 impact from the total project is 0.59 ug/m3. This impact is less than the US EPA NO2 Class II significance impact of level of 1 ug/m3, therefore, no additional PSD analysis is necessary.

Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the 24 hour PM10 NAAQS. The total project's peak 24-hour impact is 4.7 ug/m3, which is less than the Class II SIL of 5 ug/m3, therefore no additional PSD analysis is necessary.

Table 4.16 Comparison of Modeled Results to PSD Significance Thresholds

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	PSD Class II Increment Standard (ug/m3)	Significant Monitoring Concentration (ug/m3)
NO2	1-hour	95	7.52	///////	///////
	Annual	0.59	1.0	25	14
CO	1-hour	631	2,000	///////	///////
	8-hour	149	500	///////	575
PM10	24-hour*	4.7	5.0	30	10
	Annual	0.6	1.0	17	///////

Note that the 24 hour PM10 results for the PSD model are different from the NSR model results. For the PSD model AES assumed 1 CCTG operating at minimum load for 20 hours and average load for 4 hours, with the other CCTG operating at minimum load for 24 hours. For the NSR model both CCTGs were assumed to operate at miniumum load for 24 hours. ***<u>The simple cycle turbines normal operations were modeled at an emission concentration of 4.0 ppm, however during review of the PDOC, CO BACT was determined to be 2.0 ppm for these units. The modeling was not re-run however re-modeled results are expected to be less than what is presented in the table. Similarily, the combined cycle turbines normal operations were modeled at an emission concentration of 2.0 ppm, however, the during review of the PDOC, the applicant proposed a CO limit of 1.5 ppm for these units and the model was not re-run for the same reason.</u>***

For 1-hour NO2 impacts, because the peak impact level from the proposed project of 95 ug/m3 exceeds the significance impact level of 7.52 ug/m3, a NO2 cumulative impact assessment is necessary.

For the NO2 cumulative impact assessment, three facilities, Orange County Sanitation District's Huntington Beach and Fountain Valley facilities and Beta Offshore as well as emissions from shipping lane activities off the coast were selected to be included based on their facility emissions and distance to the project. Seasonal, by hour-of-day background concentrations from the Costa Mesa monitoring station were used in the modeling. Following the form of the standard, the 1-hour NO2 impact from the project plus cumulative sources plus background is 148 ug/m3, which is less than the Federal 1-hour standard of 188 ug/m3. Therefore, no additional PSD analysis is necessary.

Table 4.17 NO2 Cumulative Analysis Results

Source/Year	2010	2011	2012	2013	2014
HBEP	75.4	71.0	73.2	74.1	76.0
HBGS	5.15	5.08	5.32	5.12	4.73
OCSFV	8.92	8.92	8.87	8.91	9.02
OCSHB	56.2	54.0	54.1	54.1	53.7
BETA	58.2	63.2	62.6	66.8	66.1
SHIPS	24.3	23.4	23.9	22.6	23.3
TOTAL PLUS BACKGROUND	140	147	148	143	144

The modeled concentration is the 8th high result. Model result is added to the 98th percentile background concentration for 2010 through 2012 to obtain total concentration.

Visibility Analysis

The nearest Class I areas to the project site are the San Gabriel Wilderness and Cucamonga Wilderness areas located approximately 69 km away. A radial receptor ring was placed at a distance of 50 km from the project (50 km is the maximum receptor distance of the AERMOD model). The maximum project impact for annual NO2 at 50 km is 0.0055 ug/m3, which is less than the significance level of 0.1 ug/m3, the maximum impact for 24 hour PM10 is 0.042 ug/m3, which is less than the significance level of 0.2 ug/m3, and the maximum annual impact for annual PM10 is ~~0.32~~ **0.006** ug/m3, which is less than the significance level of 0.32 ug/m3.

A screening criteria is acceptable to use for projects located more than 50 km away from a Class I area, in order to estimate the potential impacts on visibility and deposition at these areas. The emissions/distance (Q/D) is calculated using the project's total annual emissions of SO2, NOx, PM10, and H2SO4 (based on 24 hour maximum allowable emissions) divided by the distance between the project and the nearest Class I area. Q is estimated to be 420 tpy. D would be the distance in km to the nearest Class I area (in this case Cucamonga and San Gabriel Wilderness at 69 km). Approximate Q/D is 6.1, which is less than the threshold of 10. Thus, modeling of visibility and deposition impacts to Class I areas is not necessary.

The project's impacts on visibility in Class II areas were also analyzed. Currently, there are no thresholds for visibility impacts on Class II areas. The project utilized the criteria and thresholds for visibility impacts on Class I areas. Visibility impacts are based on the calculation of two factors – plume contrast and color contrast (ΔE) of the plume when compared to the sky and terrain backgrounds. For Class I areas, the criteria used is based on a perceptibility threshold of 0.05 (absolute value) for contrast and 2.0 for ΔE. The project applicant identified five Class II areas in the project vicinity, Crystal Cove State Park, Water Canyon State Park, Chino Hills State Park, San Mateo Canyon Wilderness Area, and Huntington Beach State Park. The project impacts were determined to be below the thresholds for all areas except for Crystal Cove and Huntington Beach State Parks. The ΔE for Crystal Cove and Huntington Beach State Parks exceeded the thresholds using the Level I VISCREEN analysis. Therefore a Level 2 VISCREEN analysis was performed for these 2 areas. Using the 5 year meteorological data from the John Wayne Airport, the joint frequency distribution tables were created and were used to determine the worst case single wind speed and stability class required for a VISCREEN analysis. Using the Level 2 VISCREEN analysis, the project's impacts for both contrast and ΔE are less than the thresholds for Crystal Cove State Park but exceed the thresholds for Huntington Beach State Park.

It should be noted here that neither VISCREEN (the model used in the analysis) nor the Class I visibility thresholds were established for Class II areas in southern California, which contain numerous urban areas and lots of commercial and industrial activity. EPA requires, for informational purposes only, a visibility analysis of Class II areas using the Class I visibility thresholds and the VISCREEN model. However, this does not necessarily mean that permitting actions or project mitigation are required for any significant Class II visibility impacts that are found.

Soil and Vegetation Analysis

AES compared the HBEP's impacts and background concentrations to the secondary national ambient air quality standards with the reasoning that the standards were established to include protection against visibility impairment, and damage to animals, crops, vegetation, and buildings. Since the project emissions do not exceed the secondary NAAQS, AES concluded that there will be no significant impacts to soil and vegetation (see letter from AES dated November 11, 2015).

Table 4.18 Impacts Compared to Secondary NAAQS

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Impact (ug3/m3)	Secondary NAAQS (ug/m3)
NO2	Annual	0.59	21.8	22.4	100
SO2	3-hour	5.01	23.1	28.2	1,300
PM10	24-hour	4.7	51.0	55.7	150
PM2.5	24-hour Federal	4.7	21.3	26	35
	Annual	0.6	8.6	9.24	12

The modeling was reviewed by SCAQMD modeling staff and deemed acceptable. Refer to the memo from Ian MacMillan to Andrew Lee dated May 18, 2016.

The application documents and modeling files were forwarded to the Federal Land Managers (US Forest Service and National Park Service) on January 6, 2016 to provide these agencies the opportunity to review and comment on the potential impacts of the proposed project on Class I areas. ~~SCAQMD will not issue a final permit to AES until the land managers have issued their determinations.~~ **Both agencies have responded and indicated no adverse impacts/no comments on the proposed project.**

Expiration of permits under SCAQMD and PSD Rules for Phased Projects

This is a phased construction project. Phase 1 of the project consists of the construction of the two combined cycle turbines, their stacks and associated control equipment, the auxiliary boiler, the aqueous ammonia tank D150, and the oil water separator D152. The start of construction for Phase 1 is scheduled to begin in the 2nd quarter of 2017. Phase 2 of the project consists of the construction of the two simple cycle turbines, their stacks and associated control equipment, the aqueous ammonia tank D151, and the oil water separator D153. The start of construction for Phase 2 of the project is scheduled to begin in the 2nd quarter of 2022.

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

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

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

<u>significant interest in the initial permitting decision</u> ***<u>(Guidance on Extention of Prevention of Significant Deterioration Permits under 40 CFR 52.21(r)(2), EPA, Jan 31, 2014)</u>***

<u>Rule 1714 – PSD for Greenhouse Gases</u>

As of January 2, 2011 Greenhouse gases (GHGs) are a regulated New Source Review pollutant under the PSD permitting program when they are emitted by new sources or modifications to existing sources at amounts equal to or greater than the applicability thresholds of the GHG tailoring rule. The HBEP project will emit over 1 million tons of CO2e, and the contemporaneous increase, after considering the shutdown of Boilers 1 and 2, will exceed 75,000 tons per year. The project is therefore subject to BACT for GHGs (reference Appendix I)

For PSD purposes, GHGs are defined as a single air pollutant consisting of the sum of the following six gases:

Carbon Dioxide (CO2)
Nitrous Oxide (N20)
Methane (CH4)
Hydroflorocarbons
Perfluorocarbons
Sulfur hexafluoride (SF6)

These gases can be summed together as CO2 equivalent, or CO2e, using each gases' global warming potential (GWP). The CO2e limit as set forth in California law SB1368 under CCR Title 20 Chapter 11 Article 1 is 1,100 lb/$_{net}$MWh. The limit is based on the total annual CO2e emissions from all operations, divided by the total annual net MW generation. The limit is not, however, subject to a pre-construction review process in the permit evaluation because as the statute is written, it is the responsibility of the purchaser of the power to make the determination that the power producer they are purchasing from meets this limit prior to buying the power.

Approximate GHG emissions from the HBEP are calculated in Appendix I and summarized in Tables 3.23, 3.24, 3.25, and 3.26

<u>GHG BACT Analysis</u>

EPA has recommended the 5-step "top-down" process to determine BACT for GHGs.

1. Identify all available control options
2. Eliminate technically infeasible options
3. Ranking of controls
4. Economic, energy, and environmental impacts

5. Selecting BACT

Step 1 Identify All Available Control Options

The available CO_2 control technologies are:

A. Carbon Capture and Sequestration (CCS)
B. Thermal Efficiency

The option for lower emitting alternative technologies was not considered in the BACT analysis based on the reasoning that an alternative technology such as wind power, solar power, or battery storage would alter the fundamental business purpose of the plant. This is consistent with EPA's March 2011 PSD and Title V Permitting Guidance for Greenhouse Gases, which recognizes that the list of options chosen for Step 1 should not necessarily "redefine the nature of the source as proposed by the permit applicant..."

The technologies are described and discussed in the next sections.

A. Carbon Capture and Sequestration (CCS)

CCS is a process that captures, transports, and sequesters CO_2 emissions.

Capturing of CO_2 Emissions

Combustion flue gas or fuel gas streams may be processed for the purpose of separation and capture of carbon dioxide. The physical capture of CO2 from gas streams can be accomplished using either physical or chemical solvents or solid sorbents, with subsequent desorption to produce a concentrated CO2 stream. Typically, physical solvents are more suited to pre-combustion capture of CO2 in a fuel stream which has relatively high levels of CO2 at high pressure, while chemical solvents work better at capturing CO2 from dilute low pressure post-combustion flue gas.

Transportation of CO2 Emissions

Captured CO_2 would then need to be compressed to supercritical temperature and pressure for transport. Because of the extremely high pressures and the special fluid properties of the supercritical CO2, specialized designs are required for CO2 pipelines, and for the compressors needed to bring the CO2 to the required pressure for transport.

Sequestration of CO_2 Emissions

There are several sequestration approaches.

Geologic Sequestration

Geological sequestration is the process of injecting captured CO2 into deep subsurface rock formations for long term storage. The storage locations can be deep saline aquifers or depleted coal seams, or the use of compressed CO2 to enhance oil recovery in crude oil production operations. The process involves transporting the compressed CO_2 to a sequestration location, injecting it underground at high pressure. There it remains a supercritical fluid underground. Ideally, over time the CO_2 can dissolve into surrounding water and rocks, creating solid carbonate minerals.

Several geologic formations identified in California might provide a suitable site for geologic sequestration, including a few sites near the HBEP Project. These sites were identified in the Department of Energy (DOE) National Energy Technology Laboratory's (NETL) *2010 Carbon Sequestration Atlas of the United States and Canada*, and include some oil and gas reservoirs in the Los Angeles Basin, one being an old petroleum production area in Huntington Beach.

Ocean Storage

In lieu of injecting CO_2 underground as in geologic sequestration, ocean storage is accomplished by injecting CO_2 into the ocean water typically at depth of greater than 1,000 meters. CO_2 is expected to dissolve or form into a horizontal lens which would delay the dissolution of CO_2 into the surrounding environment. The NETL's study stated that California "may be a candidate for CO2 storage in offshore basins."

Mineral Carbonation

Mineral carbonation is the reaction of CO_2 with metal oxides to form metal carbonates. Metal oxides are abundant in silicate minerals and in waste streams. The natural reaction of CO_2 with metal oxides is a very slow process. The reaction time can be increased by enhancing the purity of these metal oxides. Large scale production of metal oxides to meet the demand of electrical generation is very energy and cost intensive.

B. Thermal Efficiency

Power generation through fossil fuel combustion is a chemical reaction process. The thermal efficiency is defined as the ratio of the net power produced and the heating values of the fuel. The heat rate, measured in Btu/kWh, is generally used as a thermal efficiency indicator. The thermal efficiency is at the highest when the reaction is at stoichiometric, and at the time when CO_2 emissions are the highest.

The following factors affect the thermal efficiency of a power plant:

- Thermal dynamic cycle selection, combined cycle versus simple cycle
- Combustion turbine performance, compression ration and turbine design temperature
- Combustion turbine startup time, load transition time
- Steam turbine startup time, load following time
- Fuel selection

Step 2 Eliminate Technically Infeasible Options

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 determine the technical feasibility. The technology is feasible only when the technology is available and applicable. A technology that is not commercially available for the scale of the project is also considered infeasible. An available technology is applicable if it can reasonably be installed and operated on the proposed project.

A. Carbon Capture and Sequestration (CCS)

The technical feasibility of each step of the CCS is discussed below.

<u>Carbon Capture Technology</u>

The *Report of the Interagency Task Force on Carbon Capture and Storage* (DOE and EPA, 2010) discusses four operating post-combustion CO2 capture systems associated with power production. All four are used on coal-based power plants where CO2 concentrations are typically 12 to 15 percent. None were being used on natural gas fired power plants, where CO2 concentrations are in the 3-5 percent range. The report further notes the lack of demonstration in practice:

Current technologies could be used to capture CO2 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 CO2 capture capacities used in current industrial processes are generally much smaller than the capacity required for purpose of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities or volumes necessary for commercial deployment.

Many current carbon capture systems are based on a chemical absorption process using amine or chilled ammonia. Upon initiation of the process, the systems require a start up time to begin the countercurrent liquid-gas absorption towers and either chilling of the ammonia solution or heating of regeneration columns for the amine systems. The HBEP turbines often times will be required to start, stop, and ramp load quickly to meet grid demands. It is technically infeasible for the carbon capture systems to start up and shut down or to make large adjustments in gas volume in the time frames required to serve this type of operation. The CCS system could operate at minimum load during periods of expected operation. However, this approach would consume energy, offsetting some of the benefit.

CO_2 Transportation

The basic technologies required for CO_2 transportation (i.e., pipeline, tanker truck, ship) are in commercial use today for a number of applications and can be considered commercially available for liquid CO_2. However, the *Task Force* report shows that there are no existing CO2 pipelines in California. Any new pipeline constructed for HBEP would need to not only overcome technical issues such as high pressures design (> 2,000 psig) and corrosion resistance, but also the issues of obtaining the necessary permits and right-of-way agreements.

CO_2 Sequestration

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 fields. Therefore CCS using geological sequestration cannot be demonstrated to be technically feasible in practice for the new power generating system.

Ocean storage is conducted by injecting supercritical liquid CO2 from either a stationary or towed pipeline at depths typically below 3,000 feet. CO2 is injected below the thermocline, creating either a rising droplet or a dense phase plume and sinking bottom gravity current. Ocean storage and its ecological impacts are still in the research phase. It is not commercially available.

Mineral carbonation is technically feasible, as reaction chemistry is well understood. However, the sequestration of CO_2 through mineral carbonation has not been demonstrated on a commercial scale.

Summary of CCS Feasibility

In summary, the post-combustion carbon capture technologies are still in the developmental stage or pilot scale projects. These technologies would not be considered commercially available for the project size of a full-scale commercial power plant. In addition, there are no comprehensive standards in place defining requirements for long term sequestration. Therefore, CCS is not yet demonstrated in practice for a commercial-scale, natural gas fired power plant such as the HBEP. In consideration of the uncertainty in the technical feasibility of CCS and its emergence as a promising technology, CCS is carried forward in this BACT analysis as a potential GHG control technology. However, substantial evidence demonstrates that CCS is not yet demonstrated as technically feasible for the HBEP project.

B. Thermal Efficiency

The California Senate Bill (SB) 1368 requires the California Public Utilities Commission (CPUC) to establish a GHG emission performance standard for all baseload utilities by February 1, 2007. The California Energy Commission (CEC) was required to establish a similar standard for local publicly owned utilities by June 30, 2007. The CEC has established a GHG performance standard of 1,100 pounds of CO_2 per net MWh for baseload publicly owned electrical utilities. The California Legislature in Assembly Bill (AB) 1613 (2007), as amended by AB 2791 (2008), established a CO_2 Emission Performance Standard (EPS) for combined heat and power facilities of 1,100 lbs CO_2/MWh. In 2010, the CEC promulgated its regulation to implement AB 1613 in its Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction Act (CEC 2010b).

It is anticipated that the HBEP plant will meet the California GHG emission performance standard of 1,100 pounds of CO_2 per net megawatt hour.

The thermal efficiency for the new power generating system achieved by the state-of-the-art technologies is a technically feasible alternative for reducing GHG emissions from a fossil-fuel fired low efficiency power plant. In conclusion the combustion process inherent in the new power generating system is achieved in practice and is eligible for consideration under Step 3 of the BACT analysis.

Step 3 - Rank Remaining Control Technologies

Because CCS is not technologically feasible, the only remaining technologically feasible option is thermal efficiency.

Step 4 – Evaluating the Most Effective Controls

Step 4 of the BACT analysis is to evaluate the most effective control. This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down approach requires that the evaluation begin with the most effective technology. Although carbon control has been deemed infeasible for the HBEP, in response to a suggestion from EPA team members on other recent projects, the economic feasibility of CCS was still evaluated by AES in this step.

A. Carbon Capture and Sequestration (CCS)

The costs of constructing and operating CCS technology would include the following:

- Licensing of scrubber technology and construction of carbon systems
- Reduction in plant output due to the high energy consumption of CCS
- Identification of oil and gas companies with depleted oil reserves having appropriate characteristics for oil recovery.
- Construction of compression systems and pipelines to deliver CO2
- Hiring of labor to operate, maintain, and monitor the capture, compression, and storage systems.

AES relied on the data from the *Task Force* report to estimate the capital cost of a CCS system for the HBEP. From this data, the cost estimate is about $467 million, which, based on an estimate of $770-$880 million for the HBEP plant itself, represents about a 50% increase in the overall cost of the plant.

Furthermore, a pipeline from HBEP to an oil field in either Santa Fe Springs or Dominguez Hills would be about 30 miles long. Costs for an 8 inch CO2 pipeline are estimated to be $600,000 per mile based on engineering analysis of the Denbury CO2 pipeline in Wyoming. Therefore, the pipeline for HBEP would be about $18 million, representing another 3 percent increase to the capital costs of the HBEP project.

B. Thermal Efficiency

AES compared the efficiency on the HBEP project to several other recently permitted similar projects in California, and found that the HBEP compares favorably. The following table summarizes their findings:

Project	Heat Rate (btu/kWh)	GHG Performance (MTCO2/MWh)
HBEP[1]	6,322 (combined cycle) 9,074 (simple cycle)	0.383
Watson Cogen[2]	5,027-6,327	0.219 – 0.318
Palmdale Hybrid Power[3]	6,970	0.370

Russell City Energy[4]	6,852	0.371
El Segundo Redevelopment[5]	6,754 (combined cycle) 8,458 (simple cycle)	0.409
Carlsbad Energy Center[6]	9,473	0.503

Notes:

1. The net heat rate of the HBEP is at 65.8° F at site elevation and relative humidity of 58.32%, no inlet air cooling. Heat rates averaged over the operating range of 50-100% load. GHG performance based on plant-wide CO2 emissions of 1,781,868 metric tons per year
2. From Watson Cogeneration Project Commission Final Decision
3. From Table 3 and 4 of the Palmdale Hybrid Power Project Greenhouse Gas BACT Analysis (AECOM 011)
4. From GHG BACT Analysis Case Study, Russell City Energy Center, November 2009, updated February 3, 2010
5. From El Segundo Power Redevelopment Project Revised Final Determination of Compliance
6. From Carlsbad Energy Center Project Amendments Final Decisoin

Step 5 – Select BACT

Based on the above analysis, thermal efficiency is the only technically and economically feasible alternative for CO_2/GHG emissions control for the HBEP Project. AES has chosen to use both combined cycle as well as simple cycle turbine technology at the Huntington Beach plant. Although simple cycle turbines are not as efficient as combined cycle units, and therefore they emit more GHG pollutants per MW output, AES has chosen this configuration to meet the anticipated needs of the energy market they serve. The simple cycle units are capable of rapid start up and response to serve the peak load demand. The combined cycle units, although able to start relatively quickly, are not designed for this type of operation. The combined cycle units, in order to achieve superior thermal efficiency, must wait for the steam turbine to reach proper operating temperature. If the combined cycle units were to bypass the the steam turbine for the purposes of a quick start, they essentially become a simple cycle unit and therefore losses any advantage they have in thermal efficiency.

Therefore, requiring AES to use only combined cycle units under the GHG BACT analysis would alter the applicant's purpose and objective of the proposed facility.

The conclusion of the GHG top down analysis is that the current design of the facility meets the BACT requirement for GHG emission reductions.

Under this analysis, a BACT limit shall be developed for both the combined cycle and simple cycle units. The BACT limit is applicable to the entire operating profile. Therefore, BACT is determined based on the facility's proposed annual operating scenarios that take into consideration load factor, equipment degradation, and operating hours. The calculated GHG emissions rate for the CCTGs is

967.6 lbs CO2/net MWh, and the calculated GHG emissions rate for the SCTGs is ~~1359.0~~ **1378.0** lbs CO2/net MWh.

Each combined cycle turbine will be subject to an emission limit of ~~870,251~~ **873,035** tons CO2 per year, and each simple cycle turbine will be subject to an emission limit of ~~103,578~~ **103,576** tons CO2 per year. Compliance will be based on a 12-month rolling average as determined by using emission factors and fuel usage.

Detailed calculations are shown in Appendix I.

- Circuit Breakers

EPA in the Pio Pico Energy Center PSD permit requires the circuit breakers be equipped with a leak detection system, and be calibrated according to manufacturer specifications. EPA considers this to be BACT for circuit breakers. EPA further argues that the requirement is not redundant to the CARB regulation to reduce GHG (SF_6) emissions from gas insulated switchgears, California Code of ~~Registers~~ **Regulations**, Subchapter 10, Article 4, §95350-§95359.

A facility condition F52.2 will be added to enforce the BACT requirement for the circuit breakers, using the same language as the EPA permit.

Other PSD Requirements

In addition to the BACT requirement the PSD requirements generally include air quality modeling, ambient monitoring, and additional impact analysis. The modeling analysis shall demonstrate that there will be no violations of any NAAQS or PSD increments. However, because there are currently no NAAQS or PSD increments established for GHGs, the modeling analysis requirement would not apply for GHGs even if PSD is triggered for GHGs. EPA does not require monitoring for GHGs in accordance with Section 52.21(i)(5)(iii) and Section 51.166(i)(5)(iii), and EPA does not require impact analysis from GHGs in the nearby Class I areas. In addition, no offsets are required for CO because this pollutant is in attainment in the South Coast Air Basin.

Rule 2011 – SOx RECLAIM, Monitoring Recording and Recordkeeping Requirements

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

Rule 2012 – NOx RECLAIM, Monitoring Recording and Recordkeeping Requirements

The turbines and auxiliary boiler will be classified as major NOx sources under NOx RECLAIM. As such, they are required to measure and record NOx concentrations and calculate mass NOx emissions with a Continuous Emissions Monitoring System (CEMS). The CEMS will include in-stack NOx and O2 analyzers, a fuel meter, and a data recording and handling system. NOx emissions are reported to AQMD on a daily basis. The CEMS system will be required to be installed within 90 days of start up. Compliance is expected.

REGULATION XXX – Title V

The Huntington Beach facility is subject to Title V, and is operating under a valid Title V permit issued on April 29, 2016. The addition of the combined cycle/simple cycle plant and auxiliary equipment will be considered a significant revision to the existing Title V permit. AES has submitted a Title V revision application A/N 578087. As a significant revision, the permit is subject to a 30 day public notice and a 45 day EPA review and comment period. The public notice requirements are discussed in more detail under the "Public Notice Requirements" section of this report.

State Regulations

California Environmental Quality Act (CEQA)

The project is subject to the licensing procedure under the California Energy Commission (CEC). ~~This procedure analyzes all aspects of the proposed project, and is subject to a public review and comment period. It is therefore considered equivalent to an Environmental Impact Report, and satisfies the requirements of CEQA. CEC's process will fully evaluate all air quality impacts for the entire project.~~ **The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. The CEC's 12-month licensing process is a certified regulatory program under CEQA. The CEC is the lead agency for the project. This procedure consists of the development of an assessment document (preliminary staff assessment, or PSA, and final staff assessment, or FSA) which examines environmental, public health and safety, and engineering aspects of the proposed HBEP, based on the information provided by the applicant, government agencies (such as the SCAQMD), interested parties, and other sources available at the time the PSA was prepared. Further, the analysis also recommends measures to mitigate significant and potentially significant environmental effects, which take the form of conditions of certification for construction, operation, maintenance, and eventual closure of the project, if approved by the CEC. The analysis describes how the implementation of the conditions of certification would reduce potential adverse impacts to insignificant levels and ensure that the project's emissions are mitigated to less than significant.**

The PSA was made available by CEC on June 24, 2016, and part 1 of the FSA was realeased on October 17, 2016

<u>Federal Regulations</u>

<u>NSPS for Small Boilers - 40CFR Part 60 Subpart Dc</u>
This performance standard applies to steam generators rated between 10 and 100 mmbtu/hr constructed after June 9, 1989. However, the emission limits are only applicable to coal or oil fired units. Since the auxiliary boiler will be fired on natural gas exclusively, only records of the amount of fuel combusted on a monthly basis is required [§60.48c(g)(2)].

<u>NSPS for Stationary Gas Turbines - 40CFR Part 60 Subpart GG</u>
This regulation has been superseded by 40CFR 60 Subpart KKKK.

<u>NSPS for Stationary Gas Turbines - 40CFR Part 60 Subpart KKKK</u>
The turbines are subject to Subpart KKKK because their heat input is greater than 10.7 gigajoules per hour (10 MMBtu per hour) at peak load, based on the higher heating value of the fuel fired. Actual unit rating is

Combined Cycle Turbines
2273E+06 btu/hr (HHV) X 1055 joules/btu = 2398.0 gigajoules/hr.

Simple Cycle Turbines
885E+06 btu/hr (HHV) X 1055 joules/btu = 933.7 gigajoules/hr.

The standards applicable for a natural gas turbine greater than 850 mmbtu/hr are as follows:

NOx: 15 ppm at 15% O2 (0.43 lbs/MWh)
SOx: 0.90 lbs/MWh discharge, or 0.060 lbs/mmbtu potential SO2 in the fuel

Monitoring
The regulation requires that the fuel consumption and water to fuel ratio be monitored and recorded on a continuous basis, or alternatively, that a NOx and O2 CEMS be installed. For the SOx requirement, either a fuel meter to measure input, or a watt-meter to measure output is required, depending on which limit is selected. Also, daily monitoring of the sulfur content of the fuel is required if the fuel limit is selected. However, if the operator can provide supplier data showing the sulfur content of the fuel is less than 20 grains/100cf (for natural gas), then daily fuel monitoring is not required.

Testing
An initial performance test is required for both NOx and SO2. For units with a NOx CEMS, a minimum of 9 RATA reference method runs is required at an operating load of +/- 25 percent of 100 percent load. For SO2, either a fuel sample methodology or a stack measurement can be used, depending on the chosen limit. Annual performance tests are also required for NOx and SO2.

Compliance with the requirements of this rule is expected.

NSPS for GHGs from Electric Generating Units - 40CFR Part 60 Subpart TTTT
This regulation applies to new combustion turbines which commence construction after January 8, 2014, and which are rated greater than 250 mmbtu/hr heat input and 25 MW power output. For a unit that supplies net power in an amount greater than its design efficiency times its potential electric output and combusts more than 90% natural gas, the applicable standard is 1,000 lbs CO2/gross. For a unit that supplies net power in an amount less than its design efficiency times its potential electric output and combusts more than 90% natural gas, the applicable standard is 120 lbs CO2/mmbtu. 50% is the highest efficiency to be used in the equation, so if a unit has a design efficiency greater than 50%, then 50% is used as the default.

Combined Cycle Turbines
The potential electrical output of each of the combined cycle units is approximately 3,038.9 GW, assuming a gross output per turbine of 346.911 MW (includes ½ the steam turbine) and 8,760 hrs/yr operation (the regulation does not take into account any limitations on operation in determining the potential output). The design efficiency is greater than 50% (on a LHV basis), therefore if the unit supplies 1,519.5 GW (0.50*3,038.9) of power or more on a 12 operating month and 3 year rolling average basis, their applicable limit would be 1,000 lbs CO2/gross MW. Calculations in Appendix I show that the units can be expected to meet this limit.

Simple Cycle Turbines
The potential electrical output of each of the simple cycle units is approximately 883.1 GW, assuming a gross output per turbine of 100.814 MW and 8,760 hrs/yr operation (the regulation does not take into account any limitations on operation in determining the potential output). The design efficiency is 42.6% (on a LHV basis),), therefore if the unit supplies less than 376.2 GW (0.426*883.1) of power on a 12 operating month and 3 year rolling average basis, the applicable limit would be 120 lbs CO2/mmbtu. EPA has established a default emission rate of 117 lbs CO2/mmbtu for natural gas fired turbines, therefore the HBEP simple cycle turbines can be expected to meet the limit. It should be noted that, based on calculations shown in Appendix I, the simple cycle turbines would not meet the 1,000 lbs CO2/gross MW standard. Therefore, it is appropriate to limit the simple cycle turbines to a maximum annual net electric sales of 376.2 GW.

For all the HBEP turbines, the actual net electric sales will be based on operating data for a 12-operating-month and 3-year-rolling average time frame. The lbs CO2 per MW for the combined cycle turbines will be calculated from this operating data to determine compliance on an ongoing basis. The facility is required to keep records of its heat input and energy output to make these determinations.

NESHAPS for Stationary Gas Turbines - 40CFR Part 63 Subpart YYYY
This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility with emissions of 10 tpy or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit. The total combined potential HAP emissions

from all the combined cycle turbines, simple cycle turbines, and auxiliary boiler are about 13 tpy, and the total formaldehyde emissions from all sources combined is about 6 tpy, therefore, AES Huntington Beach is classified as an area source of HAPs, and is not subject to this subpart (calculations can be referenced in Appendix O).

40 CFR Part 64 – Compliance Assurance Monitoring

The CAM regulation applies to emission units at major stationary sources required to obtain a Title V permit, which use control equipment to achieve a specified emission limit and which have emissions that are at least 100% of the major source thresholds on a pre-control basis. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits. Based on the emission calculations shown in Appendix O, the AES Huntington Beach facility is a major source. The combined cycle turbine pre-control emissions are greater than the major source thresholds for NOx, CO, and VOC. The combined cycle turbines will be subject to an emission limit for each of these pollutants, and will use control systems to meet these limits. The simple cycle turbine pre-control emissions are greater than the major source threshold for NOx and CO, the turbines will be subject to an emission limit for each of these pollutants, and will use control systems to meet these limits. The auxiliary boiler pre-control emissions do not trigger the thresholds for any pollutant.

Combined Cycle Turbines

NOx

- ➢ Emission Limit – NOx is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – NOx is controlled with SCR
- ✓ Requirement - As a NOx Major Source under Reclaim, the turbines are required to have CEMS under Rule 2012. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

CO

- ➢ Emission Limit – CO is subject to a ~~2.0~~ **1.5** ppm 1 hour BACT limit.
- ➢ Control Equipment – CO is controlled with the oxidation catalyst.
- ✓ Requirement – The turbines will be required to use a CO CEMS under Rule 218. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

VOC

- ➢ Emission Limit – VOC is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – VOC is controlled with the oxidation catalyst.
- ✓ Requirement – The oxidation catalyst is effective at operating temperatures above 570°F. The facility is required to maintain a temperature gauge in the exhaust (condition D12.10), which will measure the exhaust temperature on a continuous basis and record the readings on an

hourly basis. The exhaust temperature is required to be at least 570°F, (with exceptions for start ups and shutdowns). This will insure that the oxidation catalyst is operating properly.

Simple Cycle Turbines
NOx

- ➢ Emission Limit – NOx is subject to a 2.5 ppm 1 hour BACT limit.
- ➢ Control Equipment – NOx is controlled with SCR
- ✓ Requirement - As a NOx Major Source under Reclaim, the turbines are required to have CEMS under Rule 2012. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

CO

- ➢ Emission Limit – CO is subject to a ~~4.0~~ **2.0** ppm 1 hour BACT limit.
- ➢ Control Equipment – CO is controlled with the oxidation catalyst.
- ✓ Requirement – The turbines will be required to use a CO CEMS under Rule 218. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

40 CFR Part 72 - (Acid Rain Provisions)
The facility will be subject to the requirements of the federal acid rain program, because the turbines are utility units greater than 25 MW. The acid rain program is similar to RECLAIM in that facilities are required to cover SO2 emissions with "SO2 allowances" that are similar in concept to RTCs. The Huntington Beach facility was given initial allowance allocations based on the past operation of their boilers. AES can either use those allocations, or if insufficient, must purchase additional allocations to cover the operation of the new turbines. The applicant is also required to monitor SO2 emissions through use of fuel gas meters and gas constituent analyses, or, if fired with pipeline quality natural gas, as in the case of the Huntington Beach facility, a default emission factor of 0.0006 lbs/mmbtu is allowed. SO2 mass emissions are to be recorded every hour. NOx and O2 must be monitored with CEMS in accordance with the specifications of Part 75. Under this program, NOx and SOx emissions will be reported directly to the U.S. EPA. Part 75 requires that the CEMS be installed and certified within 90 days of initial startup. Compliance is expected. Note that Section K of the permit will include the Acid Rain rule references applicable to this facility, specifically Part 72 and Part 73.

Public Notice Requirements

The project is subject to public notice under Rule 212, Rule 1710, and Rule 3006. Following are the notice requirements for each rule:

Rule 212
The project is subject to the noticing requirements of paragraph (g). This paragraph requires that the notification follow the procedures of 40 CFR51, Section 51.161(b), and 40 CFR124, Section 124.10. Rule 212(g) also requires 1) the AQMD analysis and information submitted by the operator must be available for public inspection in the area affected, 2) notice by prominent advertisement in the affected area, and 3) mailing a copy of the notice to EPA, CARB, chief executives of the city and county where the source is located, any land use agencies, State and Federal Land Managers or Indian Governing Body whose lands may be affected by the project.

In addition to the above, Section 124.10 requires that the notice be sent to Federal and State agencies with jurisdiction over fish, shellfish, and wildlife resources and over coastal zone management plans, the Advisory Council on Historic Preservation, State and Historic Preservation Officers, to any unit of local government having jurisdiction over the area where the facility is proposed to be located and to each State agency having any authority under State law with respect to the construction or operation of such facility. Section 124.10(c)(ix) requires the development of a mailing list consisting of those who request in writing to be on the list, solicitations for area lists of past participants in the area of the project, and notifying the public of the opportunity to be put on the mailing list through periodic publication in the public press, newsletters, environmental bulletins, etc.

The applicant must also distribute the notification to all addresses within a ¼ mile radius of the facility.

Rule 1710
As a major modification under PSD, the project is subject to the noticing requirements of Rule 1710. SCAQMD is required to make available for public review the application submittal, the preliminary determination of compliance and any documents considered in making the determination. Noticing requirements include a newspaper notification, distribution of a notice within ¼ mile radius of the facility, and providing the notice to responsible agencies, the list of which is very similar to that specified under Rule 212, but also includes other state or local air pollution control agencies. Furthermore, SCAQMD must provide the opportunity for a public hearing on the project, consider all written comments and comments received at any public hearings available for public inspection, and notify the application of the final determination. The final determination must be made available for public inspection.

Rule 3006
Rule 3006 requires the notice be sent to those who request in writing to be on a list and other means determined by the EO to insure adequate notice to the affected public. SCAQMD generates a mailing list which consists of those who have made requests to either EPA or SCAQMD to be notified.

Rule 3006 also requires that the notice contain the following:

i) The identity and location of the affected facility;

(ii) The name and mailing address of the facility's contact person;
(iii) The identity and address of the South Coast Air Quality Management District as the permitting authority processing the permit;
(iv) The activity or activities involved in the permit action;
(v) The emissions change involved in any permit revision;
(vi) The name, address, and telephone number of a person who interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision;
(vii) A brief description of the public comment procedures provided; and,
(viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

Title V also allows for a 45 day review and comment period by the U.S. EPA.

A copy of the notice and the mailing list of those sent the notice is included in this file.

The initial public notice was published in a local newspaper on June 9, 2016, placed on SCAQMD's website, and also sent to EPA, CEC, other agency contacts, and interested parties. The notice was also mailed to addresses within ¼ mile of the facility on June 16, 2016.

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

Please refer to Appendicies V and W for more details.

RECOMMENDATION:

Based on the forgoing analysis, it is recommended that a Permit to Construct be issued following 1) completion of the 30 day public ~~and 45 day EPA review and comment period~~ **re-noticing and after all pertinent comments have been considered**, 2) **EPA's 45 day review and comment period**, 3) CEC's approval of the proposed license amendment petition, and 4) securing all necessary emission offsets **and offset exemption fees**. The following conditions shall apply:

CONDITIONS:

FACILITY-WIDE CONDITIONS

F2.1
The operator shall limit emissions from this facility as follows:

CONTAMINANT	EMISSIONS LIMIT
PM**2.5**	Less than 100 TONS IN ANY ONE YEAR

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

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

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

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

The operator shall submit written reports of the monthly PM2.5 compliance demonstrations required by this condition. The report submittal shall be included with the semi annual Title V report as required under Rule 3004(a)(4)(f). Records of the monthly PM2.5 compliance demonstrations shall be maintained on site for at least five years and made available upon SCAQMD request.
[Rule 1325]

F52.1
This facility is subject to the applicable requirements of the following rules or regulations:

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

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

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

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

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

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

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

At least 6 months prior to November 1, 2019, AES may submit a permit modification application requesting the permission to shutdown a combination of boilers other than HB Boiler 1, HB Boiler 2, and RB Boiler 7 to offset the increases for this project. The other boilers must be located at AES facilities Huntington Beach GS, Redondo Beach GS, or Alamitos GS, and approval of the application must be received prior to any changes being made to the shutdowns outlined in this condition.
[Rule 1304 – Modeling and Offset Exemption, Rule 1313]

F52.2
This facility is subject to the applicable requirements of the following rules or regulations:

For all circuit breakers at the facility utilizing SF6, the operator shall install, operate, and maintain enclosed-pressure SF6 circuit breakers with a maximum annual leak rate of 0.5 percent by weight.

The circuit breakers shall be equipped with a 10 percent by weight leak detection system. The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and all records of calibrations shall be maintained on site.

The total CO2e emissions from all circuit breakers shall not exceed 71.8 tons per calendar year.

The operator shall calculate the SF6 emissions due to leakage from the circuit breakers by using the mass balance in equation DD-1 at 40 CFR Part 98, Subpart DD on an annual basis. Records of such calculations shall be maintained on site.
[Rule 1714]

F52.3
This facility is subject to the applicable requirements of the following rules or regulations:

Rule 1304.1 Electric Generating Fee for Use of Offset Exemption

The owner/operator shall submit the annual payment for PM10 and VOC, calculated in accordance with the rule and approved by the Executive Officer, on or before the anniversary date of the commencement of operation. The owner or operator may elect to switch to the single payment option upon submittal of a written request to the Executive Officer.
[Rule 1304.1]

COMBINED CYCLE GAS TURBINE CONDITIONS

A63.6
The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM10	3,090 LBS IN ANY ONE MONTH
CO	99,076 LBS IN ANY ONE MONTH
VOC	14,109 LBS IN ANY ONE MONTH

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

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

A63.7
The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM10	6,324 LBS IN ANY ONE MONTH
CO	~~26,440~~ **24,720** LBS IN ANY ONE MONTH
VOC	7,611 LBS IN ANY ONE MONTH

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

[Rule 1303 – Offsets]

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

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

[Rule 1303 – Offsets]

A99.4

The ~~19.09~~ **16.66** LBS/MMCF NOx emission limits shall only apply during the first year of operation prior to CEMS certification for reporting NOx emissions.

[Rule 2012]

A195.6

The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

[Rule 1703-PSD, Rule 2005]

A195.7

The ~~2.0~~ **1.5** PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

[Rule 1703-PSD]

A195.8

The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

[Rule 1303(a) – BACT, Rule 1303(b)(2) - Offsets]

A195.9

The 1,000 lbs/MW-hr CO2 emissions limit(s) is averaged over a rolling 12 operating month basis. The limit shall only apply if the turbine supplies more than 1,519,500 MWh net electrical output to a utility distribution system over a rolling 12 operating month basis and a 3 year rolling average basis.

[40CFR 60 Subpart TTTT]

A327.1
For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[Rule 475]

B61.1
The operator shall not use natural gas containing the following specified compounds:

Compound	Grains per 100 scf
H2S	Greater than 0.25

This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H2S.
[Rule 1303(b) – Offset]

C1.7
The operator shall limit the number of start ups to no more than 62 in any one calendar month.

The number of cold start ups shall not exceed 15 per month, the number of ~~warm start ups shall not exceed 12 per month, and the number of hot start ups shall not exceed 35 per month~~ **non-cold start ups shall not exceed 47 per month**. Additionally, the number of cold start ups shall not exceed 80 per year, **and** the number of ~~warm start ups shall not exceed 88 per year, and the number of hot start ups shall not exceed 332 per year~~ **non-cold starts ups shall not exceed 420 per year**.

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

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

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

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

C1.8
The operator shall limit the number of shutdowns to no more than 62 in any one calendar month.

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

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

C1.9
The operator shall limit the hours of operation to no more than 6640 in any one calendar year.

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

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005, Rule 1703]

D29.5
The operator shall conduct source test(s) for the pollutant(s) identified below.

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

SOX emissions	District Lab method 307-91	District approved averaging time	Fuel Sample
VOC emissions	District method 25.3 **<u>modified</u>**	1 hour	Outlet of the SCR
PM10 emissions	EPA method 201A/District method 5.1	District approved averaging time	Outlet of the SCR
PM2.5	EPA method 201A and 202	District approved averaging time	Outlet of the SCR
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

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

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

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

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

For natural gas fired turbines only, ~~an alternative to AQMD Method 25.3~~ for the purpose of demonstrating compliance with BACT as determined by ~~CARB and~~ SCAQMD ~~may be the following~~ **<u>the operator shall use SCAQMD Method 25.3 modified as follows</u>**:

a) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,
b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
c) Analysis of Summa canisters per ~~unmodified EPA Method TO-12 (with pre-concentration) or~~ the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F

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

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

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703-PSD, Rule 2005]

D29.6

The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

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

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

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

[Rule 1303(a)(1) – BACT]

D29.7

The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location

SOX emissions	District Lab method 307-91	District approved averaging time	Fuel Sample
VOC emissions	District method 25.3 **modified**	1 hour	Outlet of the SCR
PM10 emissions	EPA method 201A/District method 5.1	District approved averaging time	Outlet of the SCR

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

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

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

For natural gas fired turbines only, ~~an alternative to AQMD Method 25.3~~ for the purpose of demonstrating compliance with BACT as determined by ~~CARB and~~ SCAQMD ~~may be the following~~ **the operator shall use SCAQMD Method 25.3 modified as follows**:

a) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,
b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
c) Analysis of Summa canisters per ~~unmodified EPA Method TO-12 (with pre-concentration) or~~ the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F

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

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

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 475]

D82.3

The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

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

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

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

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9%-%O2 d)][(Qg*HHV)/10E6], where

K	= $7.267*10^{-8}$ (lbs/scf)/ppm
Cco	= Average of 4 consecutive 15 min. average CO concentrations, ppm
Fd	= 8710 dscf/MMBTU natural gas
%O2, d	= Hourly average % by volume O2 dry, corresponding to Cco
Qg	= Fuel gas usage during the hour, scf/hr
HHV	= Gross high heating value of the fuel gas, BTU/scf

[Rule 1703-PSD]

D82.4
The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

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

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start up and the provisional certification date of the CEMS, the operator shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).
[Rule 1703 – PSD, Rule 2005, Rule 2012]

E193.3
The operator shall install this equipment according to the following requirements:

~~Construction shall commence within 12 months of the date of the Permit to Construct unless the permit is extended. but in no case should the start of construction exceed 18 months from the date of the permit to construct.~~

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

[CEQA]

E193.5
The operator shall install this equipment according to the following requirements:

Total commissioning hours shall not exceed 996 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 216 hours of operation for each turbine.

The operator shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning.

The operator shall provide SCAQMD with written notification of the initial start up date. Written records of commissioning, start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.
[Rule 1303 – BACT, Rule 1303 – Offsets, Rule 1703 – PSD, Rule 2005]

E193.6
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

The operator shall record the total net power generated in a calendar month in megawatt-hours.

The operator shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

CO_2 = 60.009 * FF

Where, CO_2 is in tons and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the CO_2 emissions in pounds per net megawatt-hour on a 12-month rolling average. The CO_2 emissions from this equipment shall not exceed 873,035 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed 967.6 pounds per net MW-hour.

The operator shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.
[Rule 1714]

E448.1
The operator shall comply with the following requirements:

The total electricity output on a gross basis from combined cycle turbines devices D115 and D124, and their common steam turbine shall not exceed 693.8 MW.

The gross electrical output shall be measured at the single generator serving each of the combined cycle turbines, and the single generator serving the common steam turbine. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15 minute averaging time period.

The operator shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon

request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.
[Rule 1303 –Offsets, Rule 2005]

I297.1
This equipment shall not be operated unless the facility holds 147,093 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. ~~The~~ RTCs held to satisfy ~~the first year of operation portion of~~ this condition may be transferred only after one year from the initial start of operation. If the ~~initial or annual~~ hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. ~~RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held.If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates.~~ This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

I298.1
This equipment shall not be operated unless the facility holds 14,803 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 9,960 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held.If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

K40.3
The operator shall provide to the District a source test report in accordance with the following specifications:

> Source test results shall be submitted to the District no later than 60 days after the source tests required under conditions D29.5, D29.6 and D29.7 are conducted.
> Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.
Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]

K67.5
The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Commissioning hours and type of control and fuel use
Date, time, and duration of each start-up and shutdown, and the type of start up (cold, ~~warm, or hot~~ **<u>or non-cold</u>**).
In addition to the requirements of a certified CEMS, natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification
Minute by minute data (NO2 and O2 concentration and fuel flow rate at a minimum) for each turbine start up and shutdown
Total annual power output in MWh
[Rule 1303(b)(2) - Offsets]

SCR CONDITIONS
(COMBINED CYCLE UNIT SCRS)

A195.10
The 5 ppmv NH3 emission limit is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

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

where,
a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 15% O2)

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

The operator shall use the above described method or another alternative method approved by the Executive Officer.
The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.
[Rule 1303(a)(1) – BACT]

D12.7
The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the ammonia flow rate. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The injected ammonia rate shall be maintained within 44.0 lbs/hr and 242.0 lbs/hr except during start ups and shutdowns
[Rule 1303(a)(1) – BACT]

D12.8
The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the exhaust temperature. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The exhaust temp at the inlet of the SCR shall be maintained between 570-692 deg F except during start up and shutdowns
[Rule 1303(a)(1) – BACT]

D12.9
The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the differential pressure. Continuous monitoring shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month. The pressure gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The differential pressure shall not exceed 1.6 inches WC.
[Rule 1303(a)(1) – BACT]

E193.3
The operator shall install this equipment according to the following requirements:

> **The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment**
>
> **Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.**
>
> **Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.**
>
> **Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.**

[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

> In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

[CEQA]

CO CATALYST
(COMBINED CYCLE UNITS CO CATALYST)

D12.10
The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the CO Catalyst.

> The operator shall also install and maintain a device to continuously record the exhaust temperature. Continuously record shall be defined as recording at least once every hour and shall be calculated based on the average of the continuous monitoring for that hour.

The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The exhaust temp at the CO Catalyst inlet shall be maintained at a minimum of 570 deg F except during start up and shutdowns.
[Rule 1303(a)(1) – BACT, Rule 1703]

E193.3
The operator shall install this equipment according to the following requirements:

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.
[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.
[CEQA]

SIMPLE CYCLE GAS TURBINE CONDITIONS

A63.8
The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM10	4,643 LBS IN ANY ONE MONTH
CO	~~8,273~~ **5,545** LBS IN ANY ONE MONTH
VOC	1,972 LBS IN ANY ONE MONTH

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

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

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

[Rule 1303 – Offsets]

A63.9

The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM10	1,747 LBS IN ANY ONE MONTH
CO	25,449 LBS IN ANY ONE MONTH
VOC	836 LBS IN ANY ONE MONTH

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

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

[Rule 1303 – Offsets]

A99.5

The 25.11 LBS/MMCF NOx emission limits shall only apply during during the first year of operation prior to CEMS certification for reporting NOx emissions.

[Rule 2012]

A195.11

The 2.5 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.

[Rule 1703-PSD, Rule 2005]

A195.12
The ~~4.0~~ **2.0** PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.
[Rule 1703-PSD]

A195.8
The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.
[Rule 1303(a) – BACT, Rule 1303(b)(2) - Offsets]

A327.1
For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[Rule 475]

B61.1
The operator shall not use natural gas containing the following specified compounds:

Compound	Grains per 100 scf
H2S	Greater than 0.25

This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H2S.
[Rule 1303(b) – Offset]

C1.10
The operator shall limit the number of start ups to no more than 62 in any one calendar month.

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

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

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

C1.11
The operator shall limit the number of shutdowns to no more than 62 in any one calendar month.

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

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

C1.12
The operator shall limit the hours of operation to no more than 2001 in any one calendar year.

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

D29.5
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District method 100.1	1 hour	Outlet of the SCR
CO emissions	District method 100.1	1 hour	Outlet of the SCR
SOX emissions	District Lab method 307-91	District approved averaging time	Fuel Sample
VOC emissions	District method 25.3 **modified**	1 hour	Outlet of the SCR
PM10 emissions	EPA method 201A/District method 5.1	District approved averaging time	Outlet of the SCR

PM2.5	EPA method 201A and 202	District approved averaging time	Outlet of the SCR
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

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

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

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

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

For natural gas fired turbines only, ~~an alternative to AQMD Method 25.3~~ for the purpose of demonstrating compliance with BACT as determined by ~~CARB and~~ SCAQMD ~~may be the following~~ **the operator shall use SCAQMD Method 25.3 modified as follows**:

d) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,
e) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
f) Analysis of Summa canisters per ~~unmodified EPA Method TO-12 (with pre-concentration) or~~ the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F

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

For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, CARB, and SCAQMD.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703-PSD, Rule 2005]

D29.6
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

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

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

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit
[Rule 1303(a)(1) – BACT]

D29.7
The operator shall conduct source test(s) for the pollutant(s) identified below.

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

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

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

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

For natural gas fired turbines only, ~~an alternative to AQMD Method 25.3~~ for the purpose of demonstrating compliance with BACT as determined by ~~CARB and~~ SCAQMD ~~may be the following~~ **<u>the operator shall use SCAQMD Method 25.3 modified as follows</u>**:

g) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,
h) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
i) Analysis of Summa canisters per ~~unmodified EPA Method TO-12 (with pre-concentration) or~~ the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F

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

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

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 475]

D82.3

The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

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

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

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

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9%-%O2 d)][(Qg*HHV)/10E6], where

K	= $7.267*10^{-8}$ (lbs/scf)/ppm
Cco	= Average of 4 consecutive 15 min. average CO concentrations, ppm
Fd	= 8710 dscf/MMBTU natural gas
%O2, d	= Hourly average % by volume O2 dry, corresponding to Cco
Qg	= Fuel gas usage during the hour, scf/hr
HHV	= Gross high heating value of the fuel gas, BTU/scf

[Rule 1703-PSD]

D82.4
The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

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

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start up and the provisional certification date of the CEMS, the operator shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).
[Rule 1703 – PSD, Rule 2005, Rule 2012]

E193.3
The operator shall install this equipment according to the following requirements:

~~Construction shall commence within 12 months of the date of the Permit to Construct unless the permit is extended. but in no case should the start of construction exceed 18 months from the date of the permit to construct.~~

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

[CEQA]

E193.7
The operator shall install this equipment according to the following requirements:

Total commissioning hours shall not exceed 280 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 4 hours of operation for each turbine.

The operator shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning.

The operator shall provide SCAQMD with written notification of the initial start up date. Written records of commissioning, start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.
[Rule 1303 – BACT, Rule 1303 – Offsets, Rule 1703 – PSD, Rule 2005]

E193.8
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

The operator shall record the total net power generated in a calendar month in megawatt-hours.

The operator shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

$CO2 = 60.009 * FF$

Where, CO2 is in tons and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the CO2 emissions in pounds per net megawatt-hour on a 12-month rolling average. The CO2 emissions from this equipment shall not exceed 103,576 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO2 emissions shall not exceed 1378.0 pounds per net MW-hour.

The operator shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.
[Rule 1714]

E448.2
The operator shall comply with the following requirements:

The total electricity output on a gross basis from simple cycle turbines devices D133 and D139 shall not exceed 201.6 MW.

The gross electrical output shall be measured at the single generator serving each of the simple cycle turbines. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15 minute averaging time period.

The operator shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.
[Rule 1303 –Offsets, Rule 2005]

E448.3
The operator shall comply with the following requirements:

This equipment shall not supply more than 43 percent of its potential electrical output or more than 376,200 MWh net electrical output to a utility distribution system on a 12 operating month rolling average and a 3 year rolling average basis

The operator shall record and maintain written records of the amount of electricity supplied to the utility distribution system expressed as a percentage of the total potential electrical output of the turbine and shall make the records available to the Executive Officer upon request.
[40CFR 60 Subpart TTTT]

I297.2
This equipment shall not be operated unless the facility holds 26,970 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. ~~The~~ RTCs held to satisfy ~~the first year of operation portion of~~ this condition may be transferred only after one year from the initial start of operation. If the ~~initial or annual~~ hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. ~~RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held.~~ This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

I298.2
This equipment shall not be operated unless the facility holds 1,660 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 1,201 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held.If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

K40.3
The operator shall provide to the District a source test report in accordance with the following specifications:

> Source test results shall be submitted to the District no later than 60 days after the source tests required under conditions D29.5, D29.6, and D29.7 are conducted.
> Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.
> All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]

K67.6

The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Commissioning hours and type of control and fuel use
Date, time, and duration of each start-up and shutdown
In addition to the requirements of a certified CEMS, natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification
Minute by minute data (NO2 and O2 concentration and fuel flow rate at a minimum) for each turbine start up
Total annual power output in MWh

[Rule 1303(b)(2) - Offsets]

SCR CONDITIONS
(SIMPLE CYCLE UNIT SCRS)

A195.10

The 5 ppmv NH3 emission limit is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

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

where,
a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 15% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months. The NOx analyzer shall be installed and operated within 90 days of initial start-up.
The operator shall use the above described method or another alternative method approved by the Executive Officer.

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

[Rule 1303(a)(1) – BACT]

D12.11

The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

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

[Rule 1303(a)(1) – BACT]

D12.12

The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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

[Rule 1303(a)(1) – BACT]

D12.13

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

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

[Rule 1303(a)(1) – BACT]

E193.3

The operator shall install this equipment according to the following requirements:

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

[CEQA]

CO CATALYST
(SIMPLE CYCLE UNITS CO CATALYST)

D12.17
The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the CO Catalyst.

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

[Rule 1303(a)(1) – BACT, Rule 1703]

E193.3
The operator shall install this equipment according to the following requirements:

> **The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment**
>
> **Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.**
>
> **Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.**
>
> **Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.**

[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

> In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

[CEQA]

AMMONIA STORAGE TANK CONDITIONS

E144.1
The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.
[Rule 1303(a)(1)-BACT]

C157.1
The operator shall install and maintain a pressure relief valve set at 50 psig.

[Rule 1303(a)(1)-BACT]

E193.3
The operator shall install this equipment according to the following requirements:

> **The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment**
>
> **Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.**
>
> **Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.**
>
> **Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.**

[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

> In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

[CEQA]

AUXILIARY BOILER CONDITIONS

A63.10
The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM10	120 LBS IN ANY ONE MONTH

CO	650 LBS IN ANY ONE MONTH
VOC	87 LBS IN ANY ONE MONTH

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

[Rule 1303 – Offsets]

A195.13

The 5.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 3 percent O2, dry. This limit shall not apply during boiler start ups.

[Rule 2005]

A195.14

The 50 PPMV CO emission limit(s) is averaged over 60 minutes at 3 percent O2, dry. This limit shall not apply during boiler start ups.

[Rule 1703-PSD]

B61.1

The operator shall not use natural gas containing the following specified compounds:

Compound	**Grains per 100 scf**
H2S	**Greater than 0.25**

This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H2S.

[Rule 1303(b) – Offset]

C1.13

The operator shall limit the number of start ups to no more than 10 in any one calendar month.

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

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

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

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

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

C1.14
The operator shall limit the heat input to no more than 189,155 mmbtu in any one calendar year.

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

D29.6
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

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

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the

CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

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

[Rule 1303(a)(1) – BACT]

D29.8

The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR
PM10 emissions	District Method 5.1	District approved averaging time	Outlet of the SCR
NH3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR
PM2.5	EPA method 201A and 202	District approved averaging time	Outlet of the SCR

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

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

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

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

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

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703-PSD, Rule 2005]

D29.9
The operator shall conduct source test(s) for the pollutant(s) identified below.

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

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

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

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

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

[Rule 1146]

D82.5
The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to ~~15~~ **3** percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the boiler, in accordance with approved SCAQMD REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the combined cycle turbine commissioning and boiler construction period. During the interim period between the initial start up and the provisional certification date of the CEMS, the operator shall comply with the requirements of Rule 2012(h)(2) and 2012(h)(3).

[Rule 1703 – PSD, Rule 2005, Rule 2012]

E193.3

~~Construction shall commence within 12 months of the date of the Permit to Construct unless the permit is extended. but in no case should the start of construction exceed 18 months from the date of the permit to construct.~~

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

[CEQA]

I297.3
This equipment shall not be operated unless the facility holds 1,313 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. ~~The~~ RTCs held to satisfy ~~the first year of operation portion of~~ this condition may be transferred only after one year from the initial start of operation. If the ~~initial or annual~~ hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. ~~RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held.~~ This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[Rule 2005]

I298.3
This equipment shall not be operated unless the facility holds 382 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds ~~360~~ **382** pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held.If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

K40.4
The operator shall provide to the District a source test report in accordance with the following specifications:

> **Source test results shall be submitted to the District no later than 60 days after the source tests required under conditions D29.6 D29.8 and D29.9 are conducted.**
> **Emission data shall be expressed in terms of concentration (ppmv) corrected to 3 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.**
> **All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.**
> **Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), and the flue gas temperatureunder which the test was conducted.**

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]

SCR CONDITIONS
(AUXILAIRY BOILER SCR)

A195.~~10~~ **15**
The 5 ppmv NH3 emission limit is averaged over 60 minutes at ~~15%~~ **3%** O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

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

where,
a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at ~~15%~~ **3%** O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months. The NOx analyzer shall be installed and operated within 90 days of initial start-up.
The operator shall use the above described method or another alternative method approved by the Executive Officer.
The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.
[Rule 1303(a)(1) – BACT]

D12.14
The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the ammonia flow rate. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The injected ammonia rate shall be maintained within 1.0 lbs/hr and 3.9 lbs/hr except during start ups and shutdowns
[Rule 1303(a)(1) – BACT]

D12.15
The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the exhaust temperature. Continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months. The exhaust temperature shall be maintained between 406-636 deg F except during start ups and shutdowns
[Rule 1303(a)(1) – BACT]

D12.16
The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

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

[Rule 1303(a)(1) – BACT]

E193.3
The operator shall install this equipment according to the following requirements:

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D150, and oil water separator D152) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the permitting authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D151, and oil water separator D153) shall commence within 18 months of June 30, 2022 unless an extension is granted by the permitting authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[Rule 205, 40 CFR Part 52]

E193.4
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02C project.

[CEQA]

Huntington Beach Energy Project
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Appendix A

Combined Cycle Turbine Criteria Pollutant Emission Calculations

Normal Operation

- Table A.1 Manufacturer Guaranteed Emissions CCTG

Pollutant	Guarantee
NOx	2.0 ppm @15%
CO	~~2.0~~ **1.5** ppm @ 15%
VOC	2.0 ppm @ 15%
PM10	See note below
SOx	See note below
NH3	5 ppm @ 15%

The manufacturer guarantee for PM10 is 10.2 lbs/hr, which includes 6.7 lbs/hr from the combustion turbine. AES provided a (total) PM10 emission rate of 8.5 lbs/hr.

There is no manufacturer guarantee for SOx. AES based short term (lbs/hr, lbs/day and lbs/month) SOx emissions on 12 ppm sulfur in the natural gas (0.75 gr/100 scf), and long term (annual) SOx on 4 ppm sulfur (0.25 gr/100 scf).

Table A.2 Combined Cycle Gas Turbine Performance Data

Ambient Conditions	110°F, 8% RH	65.8°F, 58% RH	32°F, 87% RH
Fuel Type	Nat Gas	Nat Gas	Nat Gas
Evaporative Cooling On/Off	On	On	Off
O2 Percent	13.97	13.60	13.82
H2O Percent	5.97	5.87	5.20
Exhaust Temp, °F	221	213	216
Gross Heat Rate, btu/kWh (HHV)	9,833	9,687	9,628
Turbine Heat Input, mmbtu/hr (HHV)	2,123	2,248	2,273
Turbine Fuel Use, mmscf/hr	2.03	2.15	2.16
Stack Exhaust Flow, 10^3 acfm	1250.8	1244.4	1261.9
Stack Exhaust Flow, ft3/hr (dry, @15%O2)	63,554,099	66,563,346	66,321,830
Gross Output, MW (1 CTG)	215.890	232.073	236.140
Net Output, MW (1 CTG)	215.152	231.335	235.402
	NOx		
Concentration, ppmv dry, @ 15% O2	2.0	2.0	2.0
Hourly Emissions, lb/hr	15.48	16.39	16.48
Daily Emissions, lb/day	371.5	393.4	395.5
lbs/mmcf	7.63	7.63	7.63
lbs/mmbtu	0.0073	0.0073	0.0073
lbs/gross MW-hr (1 CTG)	0.072	0.071	0.070
Lbs/net MW-hr (1 CTG)	0.072	0.071	0.070
	CO		
Concentration, ppmv @ 15% O2	~~2.0~~ **1.5**	~~2.0~~ **1.5**	~~2.0~~ **1.5**
Hourly Emissions, lb/hr	~~9.42~~ **7.07**	~~9.98~~ **7.49**	~~10.03~~ **7.52**
Daily Emissions, lb/day	~~226.1~~ **169.7**	~~239.5~~ **179.8**	~~240.7~~ **180.5**
lbs/mmcf	~~4.64~~ **3.48**	~~4.64~~ **3.48**	~~4.64~~ **3.48**
lbs/mmbtu	0.00~~44~~ **33**	0.00~~44~~ **33**	0.00~~44~~ **33**
	VOC		
Concentration, ppmv, @ 15% O2	2.0	2.0	2.0
Hourly Emissions, lb/hr	5.40	5.72	5.75
Daily Emissions, lb/day	129.6	137.3	138.0
lbs/mmcf	2.66	2.66	2.66
lbs/mmbtu	0.0025	0.0025	0.0025

Table A.2 Combined Cycle Gas Turbine Performance Data (continued)

Ambient Conditions	110°F, 8% RH	65.8°F, 58% RH	32°F, 87% RH
Fuel Type	Nat Gas	Nat Gas	Nat Gas
Evaporative Cooling On/Off	On	On	Off
O2 Percent	13.97	13.60	13.82
H2O Percent	5.97	5.87	5.20
Exhaust Temp, °F	221	213	216
Gross Heat Rate (HHV)	9,833	9,687	9,628
Turbine Heat Input, mmbtu/hr (HHV)	2,123	2,248	2,273
Turbine Fuel Use, mmscf/hr	2.03	2.15	2.16
Stack Exhaust Flow, acfm	1250.8	1244.4	1261.9
Stack Exhaust Flow, ft3/hr (dry, @15%O2)	63,554,099	66,563,346	66,321,830
Gross Output, MW (1 CTG)	215.890	232.073	236.140
Net Output, MW (1 CTG)	215.152	231.335	235.402
	SOX		
Concentration, ppmv, @ 15% O2	0.37	0.36	0.36
Hourly Emissions, lb/hr	4.60	4.81	4.86
Daily Emissions, lb/day	110.4	115.54	116.64
lbs/mmcf	2.27	2.24	2.25
lbs/mmbtu	0.0022	0.0021	0.0021
	PM10		
Hourly Emissions, lb/hr	8.50	8.50	8.50
Daily Emissions, lb/day	204	204	204
lbs/mmcf	4.19	3.95	3.94
lbs/mmbtu	0.0040	0.0038	0.0037
	NH3		
Concentration, ppm	5	5	5
Hourly Emissions, lb/hr	14.0	14.7	14.6
Daily Emissions, lb/day	336.8	352.7	351.4

Exhaust gas calculation:
1250.8(1-.0597)(520/221+460) = 898.1E+3 cfm, dry @ stack O2
898.1E+3[(20.9-13.97)/(20.9-15)] = 1054.9E+3 dscfm = 63.554 mmscfh*

Emission Rates Normal Operation

The following calculation procedure will be used to estimate the highest hourly emission rate (low temperature case) during normal operation. Although the following emissions may differ from what is reported by AES and reflected in Table A.2, the calculations below are based on a standard F factor methodology. Also note that the average hourly emission rate (annual average temperature case) is essentially the same since the maximum and average heat input and exhaust rates differ by less than 1%.

Heat Input @ 32 deg F	=	2273 mmbtu/hr		
Exhaust flow @ 32 deg F	=	2273*8710*3.54	=	70.1 mmscf/hr
Fuel use @ 32 deg F	=	2273/1050	=	2.16 mmscf/hr

Table A.3 Maximum Hourly Emissions CCTG

Pollutant	Concentration	Mass Emission Rate
	ppm	lbs/hr
NOx(1)	9.0/2.0	75.4/16.8
CO(1)	10.0/~~2.0~~ **1.5**	51.0/~~10.2~~ **7.65**
VOC	2.0	5.8
PM10	/////////	8.5
SOx	0.75 gr/100 scf fuel	4.6
NH3	5.0	15.5

(1) with DLN only/DLN + SCR & CO Catalyst

Sample Calculations:

NOx DLN+SCR (2.0 ppm*70.1 mmscf/hr*46 lbs/lb-mole)/385 cf/lb-mole = 16.8 lbs/hr

SOx calculation:
0.75 grains/100 scf fuel converts to SOx per mmcf fuel as follows: 0.75 grains/ 100 scf(lb/7000 grains)(64 lbs/lb-mole SO2/32 lbs/lb-mole S)(1E6 cf/mmcf) = 2.14 lbs SO2/mmcf fuel.

SOx (2.14 lbs SO2/mmscf)*2.16 mmscf = 4.6 lbs/hr

Start Up Operation

There are 3 basic types of starts – cold, and warm and hot. A cold start up is defined as a start of the CT that occurs when the system is at ambient temperature, which would typically occur after a period of 48 hours or more from the last shutdown. Dry Low NOx (DLN) combustors will reduce NOx to 9 ppm within 10 minutes, and the SCR will become functional within about 30 minutes. Typically, the BACT emission levels will be achieved within 60 minutes from the beginning of a cold start.

A warm start occurs after a shutdown lasting between 10 to 48 hours, and a hot start occurs after a shutdown of less than 10 hours. Both warm and hot starts will take about 30 minutes to complete.

The turbines can be shutdown in 30 minutes.

AES anticipates up to 15 cold, 12 warm, and 35 hot starts per month, and 80 cold, 88 warm, and 332 hot starts of the combined cycle turbines per year, with a maximum of 2 starts per day.

Following is a break down of emissions during start up operations.

Table A.4 Combined Cycle Cold Start Emissions Data

Pollutant	Time, minutes	Inlet, lbs/hr	Inlet Total, lbs	Reduction, %	Total Outlet, lbs
NOx	0-10	64	11	0	11
	10-20	95	16	0	16
	20-30	75	13	0	13
	30-40	75	13	56	6
	40-50	75	13	68	4
	50-60	75	13	80	3
				TOTAL	61
CO	0-10	738	123	24	93
	10-20	1351	225	28	162
	20-30	59	10	40	6
	30-40	59	10	60	4
	40-50	59	10	72	3
	50-60	59	10	80	2
				TOTAL	325
VOC	0-10	84	14	15	12
	10-20	127	21	18	17
	20-30	5	0.8	25	0.6
	30-40	5	0.8	38	0.5
	40-50	5	0.8	45	0.4
	50-60	5	0.8	50	0.4
				TOTAL	36

Totals include an engineering margin

Table A.5 Combined Cycle Warm/Hot Start Emissions Data

Pollutant	Time, minutes	Inlet, lbs/hr	Inlet Total, lbs	Reduction, %	Total Outlet, lbs
NOx	0-10	64	11	32	7
	10-20	95	16	72	4
	20-30	75	13	80	3
				TOTAL	17
CO	0-10	738	123	60	49
	10-20	1351	225	72	63
	20-30	59	10	80	2
				TOTAL	137
VOC	0-10	84	14	38	9
	10-20	127	21	45	12
	20-30	5.3	0.9	50	0.4
				TOTAL	25

Totals include an engineering margin

Shut Down Operation

A shutdown is expected to take about 30 minutes to complete. Following is a summary of the estimated emissions during a shutdown as provide by AES.

Table A.6 Combined Cycle Shutdown Emissions Data

Pollutant	Time, minutes	Inlet, lbs/hr	Inlet Total, lbs	Reduction, %	Total Outlet, lbs
NOx	0-10	53	9	80	2
	10-20	17	3	80	0.6
	20-30	100	17	43	6
				TOTAL	10
CO	0-10	1531	255	80	51
	10-20	1092	182	80	36
	20-30	439	73	68	23
				TOTAL	133
VOC	0-10	128	21	50	11
	10-20	168	28	50	14
	20-30	21	3	47	2
				TOTAL	32

Totals include an engineering margin

Table A.7 Start Up/Shutdown Emissions Per CCTG Turbine, Summary

Pollutant	Cold Start, 60 minutes	Warm Start, 30 minutes	Hot Start, 30 minutes	Shutdown
	Lbs/event	Lbs/event	Lbs/event	Lbs/event
NOx	61	17	17	10
CO	325	137	137	133
VOC	36	25	25	32

Daily Emissions

Daily emissions are calculated assuming the following emission rates per turbine:

Table A.8 Maximum Emission Rates (1 CCTG)

	NOx	CO	VOC	PM10	SOx	NH3
Normal Operations Controlled (lbs/hr)	16.8	~~10.2~~ **7.65**	5.8	8.5	4.6	15.5
Normal Operations Uncontrolled (lbs/hr)	75.4	51.0	5.8	8.5	4.6	0
Cold Start (total lbs)	61.0	325.0	36.0	8.5	4.6	0
Warm Start (total lbs)	17.0	137.0	25.0	4.25	2.3	0
Hot Start (total lbs)	17.0	137.0	25.0	4.25	2.3	0
Shutdown (total lbs)	10.0	133.0	32.0	4.25	2.3	0

Uncontrolled emission rates based on DLN without SCR, NOx=9 ppm, CO=10 ppm, VOC=2 ppm

Daily emissions are calculated on a per turbine basis for 2 potential operating scenarios. The first assumes 1 cold start, 1 hot start, 2 shutdowns and the remaining hours of the day at full load, and the second assumes 24 hrs at full load operation.

Table A.9 Controlled Daily Emissions (1 CCTG)

		Emissions, lbs					
	Duration	NOx	CO	VOC	PM10	SOx	NH3
Scenario 1							
Cold Start	1	61.0	325.0	36.0	8.5	4.6	0
Normal Operation	20.5	344.4	~~209.1~~ **156.8**	118.9	174.25	94.3	317.75
Shutdown (2)	1	20.0	266.0	64.0	8.5	4.6	0
Downtime	1	0	0	0	0	0	0
Hot Start (1)	0.5	17.0	137.0	25.0	4.25	2.3	0
TOTAL	24	442.4	~~937.1~~ **884.8**	243.9	195.5	105.8	317.75
Scenario 2							
Normal Operation	24	403.2	~~244.8~~ **183.6**	139.2	204	110.4	317.75

Table A.10 Uncontrolled Daily Emissions (1 CCTG)

		Emissions, lbs					
	Duration	NOx	CO	VOC	PM10	SOx	NH3
Scenario 1							
Cold Start	1	61.0	325.0	36.0	8.5	4.6	0
Normal Operation	20.5	1545.7	1045.5	118.9	174.25	94.3	0
Shutdown (2)	1	20.0	266.0	64.0	8.5	4.3	0
Downtime	1	0	0	0	0	0	0
Hot Start (1)	0.5	17.0	137.0	25.0	4.25	2.3	0
TOTAL	24	1643.7	1773.5	243.9	195.5	105.8	0
Scenario 2							
Normal Operation	24	1809.6	1224	139.2	204	110.4	0

Table A.11 Maximum Controlled/Uncontrolled Daily Emissions (1 CCTG)

Pollutant	Operating Scenario	Uncontrolled Daily Emissions	Controlled Daily Emissions
NOx	See Below	1809.6	442.4
CO	1 cold, 1 hot, 2 shutdowns, 20.5 hours normal	1773.5	~~937.1~~ **884.8**
VOC	24 hr normal	243.9	243.9
PM10	24 hr normal	204	204
SOx	24 hr normal	110.4	110.4
NH3	24 hr normal	/////////////	317.8

For NOx, the maximum uncontrolled emissions result from the 24 hr normal operation scenario, while the maximum controlled emissions result from the 1 cold, 1 hot, 2 shutdown scenario.

Monthly Emissions

Table A.12 Maximum Monthly Operation CCTG

Event	# Per Month	Duration/event	Duration/month, hrs
Cold Start	15	1 hour	15
Warm Start	12	30 minutes	6
Hot Start	35	30 minutes	17.5
Shutdown	62	30 minutes	31
100% Load @ 65.8 deg F	//////////////	//////////////	674.5
		Total Hrs	744

Monthly emissions and the 30 Day Averages are calculated for 2 scenarios, one assuming the maximum starts and shutdowns are based on the above operating profile, and the second assuming no start ups or shutdowns. The following factors are used:

Table A.13 Emission Factors for 30 Day Calculation CCTG

	Lbs/hr or lbs/event					
Event	NOx	CO	VOC	PM10	SOx	NH3
Cold Start	61.0	325.0	36.0	8.5	4.6	0
Warm Start	17.0	137.0	25.0	4.25	2.3	0
Hot Start	17.0	137.0	25.0	4.25	2.3	0
Shutdown	10.0	133.0	32.0	4.25	2.3	0
Normal @ 65.8 deg	16.8	~~10.2~~ **7.65**	5.8	8.5	4.6	15.5

Table A.14 30 Day Emissions /Scenario 1/ Start Ups and Shut Downs (1 CCTG)

			Emissions					
Event	Duration, hrs/month	# of events	NOx	CO	VOC	PM10	SOx	NH3
Cold	15	15	915	4875	540	127.5	69	0
Warm	6	12	204	1644	300	51	27.6	0
Hot	17.5	35	595	4795	875	148.8	80.5	0
Shutdown	31	62	620	8246	1984	263.5	142.6	0
Normal @ 65.8 deg	674.5	//////	11331.6	~~6879.9~~ **5159.9**	3912.1	5733.3	3102.7	10454.8
	Total, lbs/month		13665.6	~~26439.9~~ **24719.9**	7611.1	6324	3422.4	10454.75
	Average lbs/day		455.5	~~881.3~~ **824.0**	253.7	210.8	114.1	348.5

Table A.15 30 Day Emissions /Scenario 2/ No Starts (1 CCTG)

			Emissions					
Event	Duration, hrs/month	# of events	NOx	CO	VOC	PM10	SOx	NH3
Normal @ 65.8 deg	744	//////	12499.2	~~7588.8~~ **5691.6**	4315.2	6324	3422.4	11532
	Total, lbs/month		12499.2	~~7588.8~~ **5691.6**	4315.2	6324	3422.4	11532
	Average lbs/day		416.6	~~253.0~~ **189.7**	143.8	210.8	114.1	384.4

Table A.16 30 Day Emissions (1 CCTG)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	15 cold starts+12 warm starts+35 hot starts+62 shutdowns+674.5 hrs normal	13,665.6	455.5
CO	15 cold starts+12 warm starts+35 hot starts+62 shutdowns+674.5 hrs normal	~~26,439.9~~ **24719.9**	~~881.3~~ **824.0**
VOC	15 cold starts+12 warm starts+35 hot starts+62 shutdowns+674.5 hrs normal	7,611.1	253.7
PM10	744 hrs normal	6,324	210.8
SOx	744 hrs normal	3,422.4	114.1

Annual Emissions

Table A.17 Maximum Annual Operation CCTG

Event	# Per Year	Duration/event	Duration/yr, hrs
Cold Start	80	1 hour	80
Warm Start	88	30 minutes	44
Hot Start	332	30 minutes	166
Shutdown	500	30 minutes	250
100% Load @ 65.8 deg F	//////////////	//////////////	6100
		Total Hrs	6640

Annual emissions for the combined cycle plant are calculated assuming the following emission rates per turbine:

Table A.18 Combined Cycle Emission Rates (annual basis)

	NOx	CO	VOC	PM10	SOx	NH3
Normal Operations Controlled (lbs/hr)	16.8	~~10.2~~ **7.65**	5.8	8.5	1.5	15.5
Cold Start (total lbs)	61.0	325.0	36.0	8.5	1.5	0
Warm Start (total lbs)	17.0	137.0	25.0	4.25	0.75	0
Hot Start (total lbs)	17.0	137.0	25.0	4.25	0.75	0
Shutdown (total lbs)	10.0	133.0	32.0	4.25	0.75	0

SOx for annual emissions is based on 0.25 gr/100 scf:
0.25 grains/100 scf fuel converts to SOx per mmcf fuel as follows: 0.25 grains/ 100 scf(lb/7000 grains)(64 lbs/lb-mole SO2/32 lbs/lb-mole S)(1E6 cf/mmcf) = 0.71 lbs SO2/mmcf fuel.

SOx (0.71 SO2/mmscf) *2.16 mmscf = 1.5 lbs/hr

Table A.19 Combined Cycle Annual Emissions, Non-Commissioning Year

Operating Mode	Emissions Per Turbine, lbs					
	NOx	CO	VOC	PM10	SOx	NH3
Cold Starts	4880	26000	2880	680	120	0
Warm Starts	1496	12056	2200	374	66	0
Hot Starts	5644	45484	8300	1411	249	0
Shutdowns	5000	66500	16000	2125	375	0
Normal Operation	102480	~~62220~~**46665**	35380	51850	9150	94550
TOTAL 1 TURBINE	119500	~~212260~~**196705**	64760	56440	9960	94550
TOTAL 2 TURBINES	239000	~~424520~~**393410**	129520	112880	19920	189100

Sample Calcs:

NOx cold starts = 61 lbs/start * 80 starts/yr = 4880 lbs

PM10 warm starts = 4.25 lbs/start * 88 starts/yr = 374 lbs

SOx normal operation = 1.5 lbs/hr * 6100 hrs/yr = 9150 lbs

Appendix B

Simple Cycle Turbine Criteria Pollutant Emission Calculations

Normal Operation

- Table B.1 Manufacturer Guaranteed Emissions SCTG

Pollutant	Guarantee
NOx	2.5 ppm @15%
CO	~~4.0~~ **2.0** ppm @ 15%
VOC	2.0 ppm @ 15%
PM10	See note below
SOx	See note below
NH3	5 ppm @ 15%

The manufacturer guarantee for PM10 is 5 lbs/hr, AES provided a (total) PM10 emission rate of 6.24 lbs/hr.

There is no manufacturer guarantee for SOx. AES based short term (lbs/hr, lbs/day and lbs/month) SOx emissions on 12 ppm sulfur in the natural gas (0.75 gr/100 scf), and long term (annual) SOx on 4 ppm sulfur (0.25 gr/100 scf).

Table B.2 Simple Cycle Gas Turbine Performance Data

Ambient Conditions	110°F, 8% RH	65.8°F, 58% RH	32°F, 87% RH
Fuel Type	Nat Gas	Nat Gas	Nat Gas
Evaporative Cooling On/Off	On	On	Off
O2 Percent	14.05	14.00	14.23
H2O Percent	5.90	5.64	4.98
Exhaust Temp, °F	848	794	789
Gross Heat Rate, btu/kWh (HHV)	9,504	8,781	8,765
Turbine Heat Input, mmbtu/hr (HHV)	737	885	880
Turbine Fuel Use, mmscf/hr	0.702	0.843	0.838
Stack Exhaust Flow, 10^3 acfm	829.8	941.4	938.2
Stack Exhaust Flow, ft3/hr (dry, @15%O2)	9,425,136	11,942,847	13,301,563
Gross Output, MW (1 CTG)	77.501	100.814	100.393
Net Output, MW (1 CTG)	76.041	99.355	98.934
	NOx		
Concentration, ppmv dry, @ 15% O2	2.5	2.5	2.5
Hourly Emissions, lb/hr	6.89	8.29	8.24
Daily Emissions, lb/day	165.4	199.0	197.8
lbs/mmcf	9.81	9.83	9.83
lbs/mmbtu	0.0093	0.0094	0.0094
lbs/gross MW-hr (1 CTG)	0.089	0.082	0.082
Lbs/net MW-hr (1 CTG)	0.091	0.083	0.083
	CO		
Concentration, ppmv @ 15% O2	~~4.0~~ **2.0**	~~4.0~~ **2.0**	~~4.0~~ **2.0**
Hourly Emissions, lb/hr	~~6.72~~ **3.36**	~~8.07~~ **4.04**	~~8.02~~ **4.01**
Daily Emissions, lb/day	~~161.3~~ **80.7**	~~193.7~~ **96.9**	~~192.5~~ **96.3**
lbs/mmcf	~~9.57~~ **4.79**	~~9.57~~ **4.79**	~~9.57~~ **4.79**
lbs/mmbtu	~~0.0091~~ **0.0046**	~~0.0091~~ **0.0046**	~~0.0091~~ **0.0046**
	VOC		
Concentration, ppmv, @ 15% O2	2.0	2.0	2.0
Hourly Emissions, lb/hr	1.92	2.31	2.30
Daily Emissions, lb/day	46.1	55.4	55.2
lbs/mmcf	2.74	2.74	2.74
lbs/mmbtu	0.0026	0.0026	0.0026

Table B.2 Simple Cycle Gas Turbine Performance Data (continued)

Ambient Conditions	110°F, 7.9% RH	65.8°F, 65% RH	32°F, 86.7% RH
Fuel Type	Nat Gas	Nat Gas	Nat Gas
Evaporative Cooling On/Off	On	On	Off
O2 Percent	14.05	14.00	14.23
H2O Percent	5.90	5.64	4.98
Exhaust Temp, °F	848	794	789
Gross Heat Rate (HHV)	9,504	8,781	8,765
Turbine Heat Input, mmbtu/hr (HHV)	737	885	880
Turbine Fuel Use, mmscf/hr	0.702	0.843	0.838
Stack Exhaust Flow, 10^3 acfm	829.8	941.4	938.2
Stack Exhaust Flow, ft3/hr (dry, @15%O2)	9,425,136	11,942,847	13,301,563
Gross Output, MW (1 CTG)	77.501	100.814	100.393
Net Output, MW (1 CTG)	76.041	99.355	98.934
	SOX		
Concentration, g/100scf fuel	0.75	0.75	0.75
Hourly Emissions, lb/hr	0.96	1.16	1.15
Daily Emissions, lb/day	23.0	27.8	27.6
lbs/mmcf	1.40	1.69	1.68
lbs/mmbtu	0.0013	0.0013	0.0013
	PM10		
Hourly Emissions, lb/hr	5.92	6.24	6.24
Daily Emissions, lb/day	142.1	149.8	149.8
lbs/mmcf	8.43	7.40	7.45
lbs/mmbtu	0.0080	0.0071	0.0071
	NH3		
Concentration, ppm	5	5	5
Hourly Emissions, lb/hr	5.1	6.14	6.10
Daily Emissions, lb/day	122.4	147.4	146.4

Exhaust gas calculation:

938.2(1-.0498)(520/789+460) = 196.1E+3 cfm, dry @ stack O2

196.1E+3[(20.9-14.23)/(20.9-15)] = 221.7E+3 dscfm = 13.3 mmscfh*

Emission Rates Normal Operation

The following calculation procedure will be used to estimate the highest hourly emission rate (average temperature case) during normal operation. Although the following emissions may differ from what is reported by AES and reflected in Table B.2, the calculations below are based on a standard F factor methodology.

Heat Input @ 65.8 deg F	=	885 mmbtu/hr		
Exhaust flow @ 65.8 deg F	=	885*8710*3.54	=	27.3 mmscf/hr
Fuel use @ 65.8 deg F	=	885/1050	=	0.84 mmscf/hr

Table B.3 Maximum Hourly Emissions SCTG

Pollutant	Concentration	Mass Emission Rate
	ppm	lbs/hr
NOx(1)	25/2.5	82.0/8.2
CO(1)	100/~~4.0~~ **2.0**	198.5/~~7.9~~ **4.0**
VOC	2.0	2.3
PM10	/////////	6.24
SOx	/////////	1.80
NH3	5.0	6.0

(2) with DLN only/DLN + SCR & CO Catalyst

Sample Calculations:

NOx (2.5 ppm*27.3 mmscf/hr*46 lbs/lb-mole)/385 cf/lb-mole = 8.2 lbs/hr
DLN+SCR

SOx calculation:
0.75 grains/100 scf fuel converts to SOx per mmcf fuel as follows: 0.75 grains/ 100 scf(lb/7000 rains)(64 lbs/lb-mole SO2/32 lbs/lb-mole S)(1E6 cf/mmcf) = 2.14 lbs SO2/mmcf fuel.

SOx (2.14 SO2/mmscf)*0.843 mmscf = 1.80 lbs/hr

Start Up Operation

A start up for the simple cycle turbines lasts 30 minutes, and a shutdown lasts 13 minutes.

AES anticipates up to 62 starts per month, and 350 starts of the simple cycle turbines per year, with a maximum of 2 starts per day.

Following is a break down of emissions during start up operations.

Table B.4 Simple Cycle Turbine Start Up Emissions Data

Pollutant	Time, minutes	Inlet, lbs/hr	Inlet Total, lbs	Reduction, %	Total Outlet, lbs
NOx	0-10		4.94	0	4.94
	10-20	82	13.7	45	7.52
	20-30	82	13.7	90	1.37
				TOTAL	16.6
CO	0-10		31.67	80	6.34
	10-20	485	80.8	96	3.25
	20-30	485	80.8	96	3.25
				TOTAL	15.4
VOC	0-10		1	42	0.58
	10-20	10.5	1.75	50	0.88
	20-30	10.5	01.75	50	0.88
				TOTAL	2.8

Totals include an engineering margin

Shut Down Operation

A shutdown is expected to take about 13 minutes to complete. Following is a summary of the estimated emissions during a shutdown as provide by AES.

Table B.5 Simple Cycle Turbine Shutdown Emissions Data

Pollutant	Time, minutes	Inlet Total, lbs	Reduction, %	Total Outlet, lbs
NOx	0-13	5.67	45	3.12
CO	0-13	54.01	48	28.09
VOC	0-13	4.08	25	3.06

Totals include an engineering margin

Table B.6 Start Up/Shutdown Emissions Per SCTG Turbine, Summary

Pollutant	Start Up, 30 minutes	Shutdown, 13 Minutes
	Lbs/event	Lbs/event
NOx	16.6	3.12
CO	15.4	28.09
VOC	2.8	3.06

Daily Emissions

Daily emissions are calculated assuming the following emission rates per turbine:

Table B.7 Maximum Emission Rates (1 SCTG)

	NOx	CO	VOC	PM10	SOx	NH3
Normal Operations Controlled (lbs/hr)	8.2	~~7.9~~ **4.0**	2.3	6.24	1.80	6.0
Normal Operations Uncontrolled (lbs/hr)	82.0	198.5	2.3	6.24	1.80	0
Start (total lbs)	16.6	15.4	2.8	3.12	0.90	0
Shutdown (total lbs)	3.12	28.9	3.06	1.35	0.39	0

Uncontrolled emission rates based on DLN without SCR, NOx=25 ppm, CO=10 ppm, VOC=2 ppm

Daily emissions are calculated on a per turbine basis for 2 potential operating scenarios. The first assumes 2 starts, 2 shutdowns and the remaining hours of the day at full load, and the second assumes 24 hrs at full load operation.

Table B.8 Controlled Daily Emissions (1 SCTG)

		Emissions, lbs					
	Duration	NOx	CO	VOC	PM10	SOx	NH3
Scenario 1							
Start (2)	1	33.2	30.8	5.6	6.24	1.8	0
Normal Operation	21.57	176.9	~~170.4~~ **86.3**	49.6	134.6	38.8	129.4
Shutdown (2)	0.43	6.2	57.8	6.12	2.7	0.78	0
Downtime	1	0	0	0	0	0	0
TOTAL	24	216.3	~~259~~ **174.9**	61.3	143.5	41.4	129.4
Scenario 2							
Normal Operation	24	196.8	~~189.6~~ **96.0**	55.2	149.8	43.2	144

Table B.9 Uncontrolled Daily Emissions (1 SCTG)

		Emissions, lbs					
	Duration	NOx	CO	VOC	PM10	SOx	NH3
Scenario 1							
Start (2)	1	33.2	30.8	5.6	6.24	1.8	0
Normal Operation	21.57	1768.8	4281.6	49.6	134.6	38.8	0
Shutdown (2)	0.43	6.2	57.8	6.12	2.7	0.78	0
Downtime	1	0	0	0	0	0	0
TOTAL	24	1808.2	4370.2	61.3	143.5	41.4	0
Scenario 2							
Normal Operation	24	1968.0	4764.0	55.2	149.8	43.2	0

Table B.10 Maximum Controlled/Uncontrolled Daily Emissions (1 SCTG)

Pollutant	Operating Scenario	Uncontrolled Daily Emissions	Controlled Daily Emissions
NOx	See Below	1968	216.3
CO	See Below	4764	~~259~~ **174.9**
VOC	2 starts, 2 shutdowns, 21.57 hours normal	61.3	61.3
PM10	24 hr normal	149.8	149.8
SOx	24 hr normal	43.2	43.2
NH3	24 hr normal	/////////////	144

For NOx and CO, the maximum uncontrolled emissions result from the 24 hr normal operation scenario, while the maximum controlled emissions result from the 2 start, 2 shutdown scenario.

Monthly Emissions

Table B.11 Maximum Monthly Operation SCTG

Event	# Per Month	Duration/event	Duration/month, hrs(1)
Start	62	30 minutes	31
Shutdown	62	13 minutes	13.4
100% Load @ 65.8 deg F	/////////////	/////////////	699.6
		Total Hrs	744

Monthly emissions and the 30 Day Averages are calculated for 2 scenarios, one assuming the maximum starts and shutdowns are based on the above operating profile, and the second assuming no start ups or shutdowns. The following factors are used:

Table B.12 Emission Factors for 30 Day Calculation SCTG

	lbs/event or lbs/hr					
Event	NOx	CO	VOC	PM10	SOx	NH3
Start	16.6	15.4	2.8	3.12	0.90	0
Shutdown	3.12	28.9	3.06	1.35	0.39	0
Normal @ 65.8 deg	8.2	~~7.9~~ **4.0**	2.3	6.24	1.80	6.0

Table B.13 30 Day Emissions /Scenario 1/, Start Ups and Shut Downs (1 SCTG)

			Emissions					
Event	Duration, hrs/month	# of events	NOx	CO	VOC	PM10	SOx	NH3
Start	31	62	1029.2	954.8	173.6	193.4	55.8	0
Shutdown	13.4	62	193.4	1791.8	189.7	83.7	24.2	0
Normal @ 65.8 deg	699.6	//////	5736.7	~~5526.8~~ **2798.4**	1609.1	4365.5	1259.3	4197.6
	Total, lbs/month		6959.4	~~8273.4~~ **5545.0**	1972.4	4642.6	1339.3	4197.6
	Average lbs/day		232.0	~~275.8~~ **184.8**	65.7	154.8	44.6	139.9

Table B.14 30 Day Emissions /Scenario 2/ No Starts (1 SCTG)

			Emissions					
Event	Duration, hrs/month	# of events	NOx	CO	VOC	PM10	SOx	NH3
Normal @ 65.8 deg	744	//////	6100.8	~~5877.6~~ **2976.0**	1711.2	4642.6	1339.3	4464
	Total, lbs/month		6100.8	~~5877.6~~ **2976.0**	1711.2	4642.6	1339.3	4464
	Average lbs/day		203.4	~~195.9~~ **99.2**	57.0	154.8	44.6	148.8

Table B.15 30 Day Emissions (1 SCTG)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	62 starts +62 shutdowns+700 hrs normal	6959.4	232.0
CO	62 starts +62 shutdowns+700 hrs normal	~~8273.4~~ **5545.0**	~~275.8~~ **184.8**
VOC	62 starts +62 shutdowns+700 hrs normal	1972.4	65.7
PM10	744 hrs normal	4642.6	154.8
SOx	744 hrs normal	1339.3	44.6

Annual Emissions

Table B.16 Maximum Annual Operation SCTG

Event	# Per Year	Duration/event	Duration/yr, hrs
Start	350	30 minutes	175
Shutdown	350	13 minutes	76
100% Load @ 65.8 deg F	///////////////	///////////////	1750
		Total Hrs	2001

Annual emissions for the simple cycle plant are calculated assuming the following emission rates per turbine:

Table B.17 Simple Cycle Emission Rates (annual basis)

	NOx	CO	VOC	PM10	SOx	NH3
Normal Operations Controlled (lbs/hr)	8.2	~~7.9~~ **4.0**	2.3	6.24	0.60	6.0
Start (total lbs)	16.6	15.4	2.8	3.12	0.30	0
Shutdown (total lbs)	3.12	28.9	3.06	1.35	0.13	0

SOx for annual emissions is based on 0.25 gr/100 scf:
0.25 grains/100 scf fuel converts to SOx per mmcf fuel as follows: 0.25 grains/ 100 scf(lb/7000 rains)(64 lbs/lb-mole SO2/32 lbs/lb-mole H2S)(1E6 cf/mmcf) = 0.71 lbs SO2/mmcf fuel.

SOx (0.71 SO2/mmscf) *0.84 mmscf = 0.60 lbs/hr

Table B.18 Simple Cycle Annual Emissions, Non-Commissioning Year

Operating Mode	Emissions Per Turbine, lbs					
	NOx	CO	VOC	PM10	SOx	NH3
Starts	5810	5390	980	1092	105	0
Shutdowns	1092	10115	1071	472.5	45.5	0
Normal Operation	14350	~~13825~~ **7000**	4025	10920	1050	10500
TOTAL 1 TURBINE	21252	~~29330~~ **22505**	6076	12484.5	1200.5	10500
TOTAL 2 TURBINES	42504	~~58660~~ **45010**	12152	24969	2401	21000

Sample Calcs:

NOx starts = 16.6 lbs/start * 350 starts/yr = 5810 lbs

PM10 starts = 3.12 lbs/start * 350 starts/yr = 1092 lbs

SOx normal operation = 0.6 lbs/hr * 1750 hrs/yr = 1050 lbs

Appendix C
Commissioning and Annual Emissions

Each turbine will go through a series of tests during commissioning to prepare for commercial operation.

Combined Cycle Commissioning

The commissioning for each combined cycle turbine is expected to take up to 996 hours, for a total of 1,992 hours total commissioning for the 2 turbines. Up to 216 of those hours will be operation with no control, the rest will be partially controlled.

Table C.1 Summary of Combined Cycle Commissioning Emissions

Activity	Duration (hours)	CT Load (%)	Fuel Use		Pollutant Emission Rates (per turbine), lbs/hr			Total Emissions (per turbine), lbs				
			mmscf/hr	mmscf/activity	NOx	CO	VOC	NOx	CO	VOC	SO2	PM10
FSNL	48	10	0.69	32.96	130	1,900	270	6,240	91,200	12,960	233	408
Steam Blows	120	40	1.27	152.34	68.3	32.4	3.00	8,190	3,888	360	583	1,020
Set Unit HRSG &Steam Safety Valves	12	40	1.27	15.23	68.3	32.4	3.00	819	389	36	58.3	102
DLN Emissions Tuning	12	50	1.35	16.25	47.3	23.8	2.00	567	285	24	58.3	102
Emissions Tuning	12	60	1.49	17.90	52.5	24.8	2.00	630	298	24	58.3	102
Emissions Tuning	12	80	1.83	21.99	63.0	29.2	2.50	756	350	30	58.3	102
Verify STG on Turning Gear, Combined Blows Finalize Bypass Valve Tuning	168	80	1.83	307.84	13.9	6.42	1.63	2,328	1,078	273	816	1,428
CTG Baseload Testing/Tuning	24	100	2.17	52.16	16.2	7.60	1.95	388	182	47	117	204

Load STG/Combined Cycle (2X1)	48	50	1.35	65.01	10.4	5.23	1.30	499	251	62	233	408
STG Load Test/Combined Cycle Tuning	96	80	1.83	175.91	13.9	6.42	1.63	1,331	616	156	467	816
RATA/Pre-performance Testing	84	80	1.83	153.92	13.9	6.42	1.63	1,164	539	137	408	714
Source Testing & Drift Test Day 1	24	50	1.35	32.50	10.4	5.23	1.30	249	125	31	117	204
Source Testing & Drift Test Day 2	24	50	1.35	32.50	10.4	5.23	1.30	249	125	31	117	204
Source Testing & Drift Test Day 3	24	50	1.35	32.50	10.4	5.23	1.30	249	125	31	117	204
Source Testing & Drift Test Day 4	24	50	1.35	32.50	10.4	5.23	1.30	249	125	31	117	204
Source Testing & Drift Test Day 5	24	50	1.35	32.50	10.4	5.23	1.30	249	125	31	117	204
Source Testing & Drift Test Day 6	24	50	1.35	32.50	10.4	5.23	1.30	249	125	31	117	204
Source Testing & Drift Test Day 7	24	50	1.35	32.50	10.4	5.23	1.30	249	125	31	117	204
Performance Testing	132	100	2.17	286.88	16.2	7.60	1.95	2,134	1,004	257	642	1,122
CALISO Certification	60	75	2.17	130.4	13.4	6.18	1.63	804	371	98	292	510
TOTALS	996	///////	///////	1656.3	///////	///////	///////	27,593	101,326	14,681	4,843	8,466

Shaded activities reflect control by DLN, SCR and oxidation catalyst. Assumed control efficiencies – NOx – 78%, CO -78%, and VOC – 35%
PM10 based on 8.5 lbs/hr, SOx based on 4.86 lbs/hr

Table C.2 Combined Cycle Simultaneous Commissioning

Both turbines will operate during the following tests. (The total emissions from these tests are accounted for in Table C.1, this table shows the higher lbs/hr emission rates due to 2 turbines operating simultaneously).

Activity	Duration (hours)	CT Load (%)	Pollutant Emission Rates, lbs/hr per turbine			Total Emissions Rate (2 turbines), lbs/hr				
			NOx	CO	VOC	NOx	CO	VOC	SOx	PM10
FSNL	48	10	130	1,900	270	260	3800	540	9.72	17
Steam Blows	120	40	68.3	32.4	3.00	136.6	64.8	6	9.72	17
Set unit HRSG and steam safety valves	12	40	68.3	32.4	3.00	136.6	64.8	6	9.72	17
STG Bypass Valve Tuning HRSG Blowdown	168	80	63.0	29.2	2.50	126	58.4	5	9.72	17

Shaded activities reflect control by DLN, SCR and oxidation catalyst. Assumed control efficiencies – NOx – 78%, CO -78%, and VOC – 35%. SOx based on 4.86 lbs/hr per turbine, PM10 based on 8.5 lbs/hr per turbine

Simple Cycle Commissioning

The commissioning for each simple cycle turbine is expected to take up to 280 hours, for a total of 560 hours total commissioning for the 2 turbines. Up to 4 of those hours will be operation with no control, the rest will be partially controlled.

Table C.3 Summary of Simple Cycle Commissioning Emissions

Activity	Duration (hours)	CT Load (%)	Fuel Use		Pollutant Emission Rates (per turbine), lbs/hr			Total Emissions (per turbine), lbs				
			mmscf/hr	mmscf/activity	NOx	CO	VOC	NOx	CO	VOC	SO2	PM10
FSNL	4	5	0.183	0.74	40.1	244.0	5.1	160.2	976.0	20.3	6.6	25.0

DNL Emission Tuning	12	100	0.838	10.06	20.5	90.0	3.1	246.0	1,080.0	36.7	19.7	74.9
Emission Tuning	12	75	0.614	7.37	16.5	72.5	2.7	198.0	869.4	32.2	19.7	74.9
Base Load Testing	12	75	0.614	7.37	16.5	72.5	1.1	198.0	869.4	13.7	19.7	74.9
Refire	12	100	0.838	10.06	20.5	90.0	3.1	246.0	1,080.0	36.7	19.7	74.9
Source Testing/RATA/Pre-performance Testing	168	100	0.838	140.80	20.5	90.0	3.1	3,440.0	15,120.0	513.3	275.5	1,048.3
Water Wash & Performance Prep	24	100	0.838	20.11	20.5	90.0	3.1	492.0	2,160.0	73.3	39.4	149.8
Performance Testing	24	100	0.838	20.11	20.5	90.0	3.1	492.0	2,160.0	73.3	39.4	149.8
CALISO Certification	12	100	0.838	10.06	20.5	90.0	3.1	246.0	1,080.0	36.7	19.7	74.9
TOTALS	280	///////		227.7	///////	///////	///////	5,718	25,449	836	459	1,747

Shaded activities reflect control by DLN, SCR and oxidation catalyst. Assumed control efficiencies – NOx – 75%, CO -75%, and VOC – 33%
PM10 based on 6.24 lbs/hr, SOx based on 1.64 lbs/hr

Table C.4 Simple Cycle Simultaneous Commissioning

Both turbines will operate during the following tests. ((The total emissions from these tests are accounted for in Table C.3, this table shows the higher lbs/hr emission rates due to 2 turbines operating simultaneously). All simple cycle commissioning activities can potentially be conducted simultaneously on both turbines, however, it is more likely that the activities up to re-fire will be done on the first turbine alone, after which the second turbine would begin its commissioning.

Activity	Duration (hours)	CT Load (%)	Pollutant Emission Rates, lbs/hr per turbine			Total Emission Rate (2 turbines), lbs/hr				
			NOx	CO	VOC	NOx	CO	VOC	SOx	PM10
FSNL	4	5	40.1	244.0	5.1	80.2	488	10.2	3.28	12.48
DNL Emission Tuning	12	100	20.5	90.0	3.1	41	180	6.2	3.28	12.48
Emission Tuning	12	75	16.5	72.5	2.7	33	145	5.4	3.28	12.48
Base Load Testing	12	75	16.5	72.5	1.1	33	145	2.2	3.28	12.48
Refire	12	100	20.5	90.0	3.1	41	180	6.2	3.28	12.48
Source Testing/RATA/Pre-performance Testing	168	100	20.5	90.0	3.1	41	180	6.2	3.28	12.48
Water Wash & Performance Prep	24	100	20.5	90.0	3.1	41	180	6.2	3.28	12.48
Performance Testing	24	100	20.5	90.0	3.1	41	180	6.2	3.28	12.48
CALISO Certification	12	100	20.5	90.0	3.1	41	180	6.2	3.28	12.48

Shaded activities reflect control by DLN, SCR and oxidation catalyst. Assumed control efficiencies – NOx – 75%, CO -75%, and VOC – 33%
PM10 based on 6.24 lbs/hr, SOx based on 1.64 lbs/hr

Table C.5 Total Commissioning Emissions (Per Block)

Pollutant	Combined Cycle Per Turbine	Total Combined Cycle Block		Simple Cycle Per Turbine	Total Simple Cycle Block	
	Lbs	Lbs	Tons	Lbs	Lbs	Tons
NOx	27,593	55,186	27.6	5,718	11,436	5.7
CO	101,326	202,652	101.3	25,449	50,898	25.4
VOC	14,681	29,362	14.7	836	1,672	0.84
PM10	8,466	16,932	8.5	1,747	3,494	1.7
SO2	4,843	9,686	4.8	459	918	0.46

Annual Emissions During Commissioning

The following is an estimate of annual emissions during a commissioning year, which may include commissioning activities as well as normal operation of the turbines and auxiliary boiler.

Commissioning of the combined cycle units will not coincide with any operation of the simple cycle units (combined cycle units start operation in 2020, simple cycle units don't begin construction until 2022). So, the annual emissions for the plant when the combined cycle units are commissioned will consist of 996 hrs of commissioning per turbine + the balance of the 12 months with normal turbine operation and auxiliary boiler operation. It will be assumed that the CCTGs and auxiliary boiler will operate their full allotment of allowable annual operating hours after commissioning. Note that in the modeling performed for annual NOx during the year commissioning is performed on the combined cycle turbines, emissions of 101,009 lbs per year of NOx (11.5 lbs/hr) were assumed. This assumption includes the CCTG operating at minimum load conditions (about 44%) after commissioning, not maximum load. This is because the CCTG minimum load emissions and associated stack parameters resulted in a higher impact than assuming full load emissions and stack parmaters.

Table C.6 Total Plant Annual Emissions, Combined Cycle Commissioning Year

Operating Mode	Hours	Emissions, lbs				
		NOx	CO	VOC	PM10	SOx
Commissioning CCTG 1	996	27,593	101,326	14,681	8,466	4,843
Commissioning CCTG 2	996	27,593	101,326	14,681	8,466	4,843
Post Commissioning Operation CCTG 1	6640	119,500	~~212,260~~**196,705**	64,760	56,440	9,960
Post Commissioning Operation CCTG 2	6640	119,500	~~212,260~~**196,705**	64,760	56,440	9,960
Auxiliary Boiler	2573.3	1,313	7,522	1,010	1,392	382
	TOTAL EMISSIONS	295,499	~~634,694~~**603,584**	159,892	131,204	29,988

Emissions during the 12 months when the simple cycle units are commissioned will consist of 280 hrs per simple cycle turbine commissioning + normal operation of the combined cycle plant and auxiliary boiler, and balance of the year with simple cycle operation.

Table C.7 Total Plant Annual Emissions, Simple Cycle Commissioning Year

Operating Mode	Hours	Emissions, lbs				
		NOx	CO	VOC	PM10	SOx
Commissioning SCTG 1	280	5,718	25,449	836	1,747	459
Commissioning SCTG 2	280	5,718	25,449	836	1,747	459
Post Commissioning Operation SCTG 1	2001	21,252	~~29,330~~ **22,505**	6,076	12,484.5	1,200.5
Post Commissioning Operation SCTG 2	2001	21,252	~~29,330~~ **22,505**	6,076	12,484.5	1,200.5
CCTG 1	6640	119,500	~~212,260~~**196705**	64,760	56,440	9,960
CCTG 2	6640	119,500	~~212,260~~**196705**	64,760	56,440	9,960
Auxiliary Boiler	2573.3	1,313	7,522	1,010	1,392	382
TOTAL EMISSIONS		294,253	~~541,600~~**496840**	144,354	142,735	23,621

Monthly Emissions During Commissioning

The following is an estimate of monthly maximum emissions during commissioning. The estimate of commissioning emissions during a 30 day period is performed to compare to the monthly maximum emissions during normal operation of the entire plant (see Table 3.13). The higher monthly amount is required to be offset (for VOC and PM10).

Scenario 1 - Combined Cycle Commissioning

When the combined cycle units are commissioned sometime in late 2019 or early 2020, neither the simple cycle units nor the auxiliary boiler will be in operation yet. Therefore, it is only the emissions from the combined cycle units commissioning itself which will need to be compared to the maximum monthly emissions from normal operation outside of commissioning.

Since the total hours for combined cycle commissioning exceeds the total hours in one month (996 vs. 744), and since the exact commissioning schedule is unknown, an assumption must be made as to the number of hours and which commissioning activities could reasonably be completely in one month's time. For argument's sake, it will be assumed that the first 636 hours of combined cycle commissioning activities will be completed in one month (up to and including the RATA testing).

Table C.8 Estimated 30 Day Emissions CCTG Commissioning Month

Pollutant	CCTG 1 Commissioning, lbs/month[1]	CCTG 2 Commissioning, lbs/month[1]	Total Facility Emissions, lbs/month	30-Day Average Emissions, lbs/day
NOx	22922	22922	45844	1528.1
CO	99076	99076	198152	6605.1
VOC	14109	14109	28218	940.6
PM10	3090	3090	6180	206.0
SOx	5406	5406	10812	360.4

1 Refer to Table C.1

Scenario 2 – Simple Cycle Commissioning

When the simple cycle units are commissioned sometime in late 2023 or early 2024, the combined cycle units and auxiliary boiler will be operating normally. Therefore, the monthly emissions from commissioning of the simple cycle units should be added to the monthly emissions from the combined cycle units and auxiliary boiler to make the comparison. Furthermore, the expected hours of commissioning for the simple cycle units (280) can be assumed to fall into one month's time.

Table C.9 Estimated 30 Day Emissions SCTG Commissioning Month

Pollutant	SCTG 1 Commissioning, lbs/month[1]	SCTG 1 Commissioning, lbs/month[1]	CCTG 1, lbs/month[2]	CCTG 2, lbs/month[2]	Aux Boiler, lbs/month[3]	Total Facility Emissions, lbs/month	30-Day Average Emissions, lbs/day
NOx	5718	5718	13666	13666	175	38943	1298.1
CO	25449	25449	~~26440~~**24720**	~~26440~~**24720**	1070	~~104848~~**101408**	~~3494.9~~**3380.3**
VOC	836	836	7611	7611	142	17036	567.9
PM10	459	459	6324	6324	196	13762	458.7
SOx	1747	1747	3422	3422	54	10392	346.4

1 Refer to Table C.5, 2 Refer to Table A.16, 3 Refer to Table D.6

A comparison of Tables C.8 and C.9 shows that the monthly emissions during combined cycle turbine commissioning are higher than the monthly emissions during simple cycle turbine commissioning in all cases except PM10. Furthermore, in a comparison of Tables 3.13 and Tables C.8 and C.9, the estimated monthly emissions during combined cycle turbine commissioning will be higher for NOx, CO, VOC, and SOx, than the maximum monthly emissions during normal operation of the entire plant outside of commissioning. Only monthly PM10 emissions are calculated to be higher during operation if the plant outside of commissioning.

Appendix D

Auxiliary Boiler Emission Calculations

Normal Operation

- Table D.1 Emission Factors Auxiliary Boiler

Pollutant	Factor	Source
NOx	5 ppm @3%	Manufacturer guarantee
CO	50 ppm @ 3%	Manufacturer guarantee
VOC	5.5 lbs/mmcf	Form B-1
PM10	7.5 lbs/mmcf	Form B-1
SOx	0.75 gr/100 scf	See note below
NH3	5 ppm @ 3%	Manufacturer guarantee

SOx emissions are based on 12 ppm sulfur in the natural gas (0.75 gr/100 scf).

Data:

Specific Molar Volume
385 ft3/lb-mole

Heat Input
71 mmbtu/hr

Exhaust flow
723,540 ft3/hr (based on F factor of 8710 corrected to 3% O2)

Fuel Use
67,619 ft3/hr (based on 1050 btu/ft3)

Start Up Operation

There are 3 basic types of starts for the auxiliary boiler– cold, and warm and hot. A cold start up is defined as a start of the boiler that occurs when the system is at ambient temperature, which would typically occur after a period of 48 hours or more from the last shutdown. Typically, the BACT emission levels will be achieved within 170 minutes from the beginning of a cold start.

A warm start occurs after a shutdown lasting between 10 to 48 hours, and a hot start occurs after a shutdown of less than 10 hours. Warm starts will take about 85 minutes to complete, and hot starts will take about 25 minutes.

AES anticipates up to 2 cold, 4 warm, and 4 hot starts per month, and 24 cold, 48 warm, and 48 hot starts of the auxiliary boiler per year, with a maximum of 1 start per day.

Table D.2 Start Up Emissions Auxiliary Boiler

Pollutant	Cold Start, 170 minutes		Warm Start, 85 minutes		Hot Start, 25 minutes	
	Lbs/hr	Lbs/event	Lbs/hr	Lbs/event	Lbs/hr	Lbs/event
NOx	1.49	4.22	1.49	2.11	0.87	0.62
CO	1.53	4.34	1.53	2.17	2.29	0.64

The lbs/hr numbers represent the highest hour during the event

Hourly Emissions

Table D.3 Hourly Emission Rates Auxiliary Boiler

	NOx	CO	VOC	PM10	SOx	NH3
Normal Operations Controlled (lbs/hr)	0.42	2.83	0.37	0.51	0.14	0.16
Normal Operations Uncontrolled (lbs/hr)	0.76	2.83	0.37	0.51	0.14	0
Cold Start (total lbs)	4.22	4.34	1.05	1.45	0.40	0
Warm Start (total lbs)	2.11	2.17	0.52	0.72	0.20	0
Hot Start (total lbs)	0.62	0.64	0.15	0.21	0.06	0

Sample Calcs:

$NOx_{normal\ controlled}$ = (5 ppm * 723,540 * 46)/ 385E+06 = 0.42

$NOx_{normal\ uncontrolled}$ = (9 ppm * 723,540 * 46)/ 385E+06 = 0.76

VOC_{normal} = (5.5 lbs/mmcf*67,619)/1E+06 = 0.37

SOx:
0.75 grains/100 scf fuel converts to SOx per mmcf fuel as follows: 0.75 grains/ 100 scf(lb/7000 grains)(64 lbs/lb-mole SO2/32 lbs/lb-mole H2S)(1E6 cf/mmcf) = 2.14 lbs SO2/mmcf fuel.

SOx_{normal} = (2.14 SO2/mmscf *67,619 mmscf)/1E+06 = 0.14 lbs/hr

$VOC_{cold\ start}$ = (170 min/60 min)*0.37 lbs/hr = 1.05

Daily Emissions

Daily emissions are calculated for 2 potential operating scenarios. The first assumes 1 cold start and the remaining hours of the day at full load, and the second assumes 24 hrs at full load operation.

Table D.4 Auxiliary Boiler Daily Controlled Emissions

		Emissions, lbs					
	Duration	NOx	CO	VOC	PM10	SOx	NH3
Scenario 1							
Cold Start (1)	2.83	4.22	4.34	1.05	1.45	0.4	0
Normal Operation	21.17	8.89	59.91	7.83	10.80	2.96	3.39
TOTAL	24	13.11	64.25	8.88	12.25	3.36	3.39
Scenario 2							
Normal Operation	24	10.08	67.92	8.88	12.25	3.36	3.84

Table D.5 Auxiliary Boiler Daily Uncontrolled Emissions

		Emissions, lbs					
	Duration	NOx	CO	VOC	PM10	SOx	NH3
Scenario 1							
Cold Start (1)	2.83	4.22	4.34	1.05	1.45	0.4	0
Normal Operation	21.17	16.09	59.91	7.83	10.80	2.96	0
TOTAL	24	20.31	64.25	8.88	12.25	3.36	0
Scenario 2							
Normal Operation	24	18.24	67.92	8.88	12.25	3.36	0

Table D.6 Maximum Controlled/Uncontrolled Daily Emissions

Pollutant	Operating Scenario	Uncontrolled Daily Emissions	Controlled Daily Emissions
NOx	1 cold start + 21.17 hours normal operation	20.3	13.1
CO	24 hr normal	67.9	67.9
VOC	24 hr normal	8.9	8.9
PM10	24 hr normal	12.3	12.3
SOx	24 hr normal	3.4	3.4
NH3	24 hr normal	/////////////	3.8

Monthly Emissions

Monthly emissions and the 30 Day Averages are calculated for 2 scenarios, one assuming the maximum starts and shutdowns are based on the monthly operating profile, and the second assuming no start ups or shutdowns.

Table D.7 Maximum Monthly Operation Auxiliary Boiler

Event	# Per Month	Duration	Duration/month, hrs
Cold Start	2	170 minutes	5.7
Warm Start	4	85 minutes	5.7
Hot Start	4	25 minutes	1.7
Normal	/////////////	15,793 mmbtu	222.4[(1)]
		Total Hrs	235.5

1 Based on 71 mmbtu/hr. Note that the unit may operate more hours at a lower heat input rate

Table D.8 30 Day Emissions Scenario 1/Start Ups and Shutdowns

	Emissions				
Event	NOx	CO	VOC	PM10	SOx
Cold Start	8.4	8.7	2.1	2.9	0.8
Warm Start	8.4	8.7	2.1	2.9	0.8
Hot Start	2.5	2.6	0.63	0.8	0.2
Normal	93.4	629.5	82.3	113.4	31.1
Total, lbs/month	112.7	649.5	87.1	120.0	32.9
Average lbs/day	3.8	21.7	2.9	4.0	1.1

Table D.9 30 Day Emissions /Scenario 2/ No Starts

	Duration		Emissions					
Event	mmbtu/month	hrs/month	NOx	CO	VOC	PM10	SOx	NH3
Normal	15,793	222.4	93.4	629.5	82.3	113.4	31.1	35.6
	Total, lbs/month		93.4	629.5	82.3	113.4	31.1	35.6
	Average lbs/day		3.1	21.0	2.7	3.8	1.0	1.2

1 based on 71 mmbtu/hr

Table D.10 30 Day Emissions

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	2 cold starts +4 warm starts + 4 hot starts + 235.5 hrs normal	112.7	3.8
CO	2 cold starts +4 warm starts + 4 hot starts + 235.5 hrs normal	649.5	21.7
VOC	2 cold starts +4 warm starts + 4 hot starts + 235.5 hrs normal	87.1	2.9
PM10	2 cold starts +4 warm starts + 4 hot starts + 235.5 hrs normal	120.0	4.0
SOx	2 cold starts +4 warm starts + 4 hot starts + 235.5 hrs normal	32.9	1.1

Annual Emissions

Table D.11 Maximum Annual Operation Auxiliary Boiler

Event	# Per Year	Duration	Duration/yr, hrs
Cold Start	24	170 minutes	68
Warm Start	48	85 minutes	68
Hot Start	48	25 minutes	20
Normal	/////////////	182,703 mmbtu	2573.3(1)
		Total Hrs	2729.3

1 *Based on 71 mmbtu/hr. Note that the unit may operate more hours at a lower heat input rate*

Table D.12 Annual Emissions Auxiliary Boiler

	Emissions					
Event	NOx	CO	VOC	PM10	SOx	NH3
Cold Start	101.3	104.2	25.2	34.8	9.6	0
Warm Start	101.3	104.2	25.2	34.6	9.6	0
Hot Start	29.8	30.7	7.4	10.1	2.9	0
Normal	1080.8	7282.4	952.1	1312.4	360.3	411.7
Total, lbs/yr	1313.2	7521.5	1009.9	1391.9	382.4	411.7

Sample Calc:

NOx = 24*(4.22) + 48*(2.11) + 48*(0.62) + 2573.3*(0.42) = 1313.2

Appendix E

Air Toxic Emission Calculations

Combined Cycle Turbines

Data:

Maximum fuel use (@ 1050 btu/cf) 2.16 mmcf/hr
Maximum annual hours of operation (incl start/shutdown) 6,640 hrs/yr

Total Annual Fuel Use	14,342 mmcf/yr

Table E.1 Toxic Emissions Per Combined Cycle Turbine

Pollutant	Emission Factor, lbs/mmcf	Maximum Hourly Emission Rate, lbs/hr	Annual Emissions 1 Turbine, lbs/yr
Ammonia	//////////////	15.5	94550
1,3 Butadiene	4.39E-04	9.48E-04	6.30
Acetaldehyde	1.80E-01	3.89E-01	2581.56
Acrolein	3.69E-03	7.97E-03	52.92
Benzene	3.33E-03	7.19E-03	47.76
Ethyl Benzene	3.26E-02	7.04E-02	467.55
Formaldehyde	3.67E-01	7.93E-01	5263.51
Naphthalene	1.33E-03	2.87E-03	19.07
PAH	9.18E-04	1.98E-03	13.17
Propylene Oxide	2.96E-02	6.39E-02	424.52
Toluene	1.33E-01	2.87E-01	1907.49
Xylene	6.53E-02	1.41E-01	936.53
		Total Lbs/yr	106,270.4
		Tons/yr	53.1

Notes:

Emission factors from USEPA AP-42 Table 3.1-3, except 1) Formaldehyde, Benzene, and Acrolein emission factors which are from the Background document for AP-42 Section 3.1, Table 3.4-1 for natural gas turbine with CO catalyst. Ammonia emissions based on 5 ppm NH3 slip, 6100 hours/yr operation (not including start/shutdown). The emission estimates in this table may differ slightly from what was used in the HRA. For the HRA AES assumed fuel use at the annual average temperature, not the site low temperature.

Simple Cycle Turbines

Data:

Maximum fuel use (@ 1050 btu/cf) 0.85 mmcf/hr
Maximum annual hours of operation (incl start/shutdown) 2,001 hrs/yr

Total Annual Fuel Use	1,701 mmcf/yr

Table E.2 Toxic Emissions Per Simple Cycle Turbine

Pollutant	Emission Factor, lbs/mmcf	Maximum Hourly Emission Rate, lbs/hr	Annual Emissions 1 Turbine, lbs/yr
Ammonia	/////////////	6.0	10500
1,3 Butadiene	4.39E-04	3.73E-04	0.75
Acetaldehyde	1.80E-01	1.53E-01	306.18
Acrolein	3.69E-03	3.14E-03	6.28
Benzene	3.33E-03	2.83E-03	5.66
Ethyl Benzene	3.26E-02	2.77E-02	55.45
Formaldehyde	3.67E-01	3.12E-01	624.27
Naphthalene	1.33E-03	1.13E-03	2.26
PAH	9.18E-04	7.80E-04	1.56
Propylene Oxide	2.96E-02	2.52E-02	50.35
Toluene	1.33E-01	1.13E-01	226.23
Xylene	6.53E-02	5.55E-02	111.08
		Total Lbs/yr	11890.1
		Tons/yr	5.95

Notes:

Emission factors from USEPA AP-42 Table 3.1-3, except 1) Formaldehyde, Benzene, and Acrolein emission factors which are from the Background document for AP-42 Section 3.1, Table 3.4-1 for natural gas turbine with CO catalyst. Ammonia emissions based on 5 ppm NH3 slip, 1750 hours/yr operation (not including start/shutdown).

Auxiliary Boiler

Data:

Maximum fuel use (@ 1050 btu/cf) 0.07 mmcf/hr
Maximum annual hours of operation (incl starts) 2,573.3 hrs/yr
Total Annual Fuel Use 180 mmcf/yr

Table E.3 Toxic Emissions Auxiliary Boiler

Pollutant	Emission Factor, lbs/mmcf	Maximum Hourly Emission Rate, lbs/hr	Annual Emissions, lbs/yr
Ammonia	//////////////	0.16	411.7
Benzene	5.80E-03	4.06E-04	1.04
Formaldehyde	1.23E-02	8.61E-04	2.21
PAH	1.00E-04	7.00E-06	0.02
Naphthalene	3.00E-04	2.10E-05	0.05
Acetaldehyde	3.10E-03	2.17E-04	0.56
Acrolein	2.70E-03	1.89E-04	0.49
Toluene	2.65E-02	1.86E-03	4.77
Xylene	1.97E-02	1.38E-03	3.55
Ethyl Benzene	6.90E-03	4.83E-04	1.24
Hexane	4.60E-03	3.22E-04	0.83
Propylene	5.30E-01	3.71E-02	95.40
		Total Lbs/yr	521.86
		Tons/yr	0.26

Notes:

Emission factors from Ventura County APCD.
Ammonia emissions based on 5 ppm NH3 slip, 2573.5 hours/yr operation (not including start/shutdown)

Appendix F

Oil Water Separator Emission Calculations

There will be 2 new oil water separators (OWS), 1 serving the combined cycle plant area, and the other serving the simple cycle turbine area. The separators will collect rainwater runoff which may contain any oil from spills on the ground or from any oily residues on the equipment itself. These oils will consist mainly of heavy lubricating oils.

Data:

OWS #1 Collection Area (combined cycle area)
115,359 FT2

OWS #2 Collection Area (simple cycle area)
14,692 FT2

Huntington Beach Yearly Average Precipitation
11.9 inches (30 year average, source www.weatherbase.com)

VOC Emission Factor
0.2 lbs/1000 gals (source Table 5.1-3 EPA AP-42)

Calculations:

OWS #1

(115,359 FT2 * 11.9/12 FT/yr precipitation)*7.48 gallons/FT3 = 855,695 gals/yr

855,695 gals/yr*0.2 lbs/1000 gals = $\boxed{\text{171.1 lbs/yr}}$

OWS #2

(14,692 FT2 * 11.9/12 FT/yr precipitation)*7.48 gallons/FT3 = 108,980 gals/yr

108,980 gals/yr*0.2 lbs/1000 gals = $\boxed{\text{21.8 lbs/yr}}$

Appendix G

Existing Facility Emissions

The existing facility consists of utility Boilers 1 and 2. The boilers are natural gas fired, each rated at 2021 mmbtu/hr heat input and 215 MW power output. The boilers are controlled with SCR systems. NOx is limited to 7 ppm on an annual average basis. EPA Acid Rain data for monthly heat input was obtained for the years 2011-2015 in order for the actual emissions of these units to be calculated. The fuel use is estimated using a heat content of 1050 btu/cf. The emission factors used to estimate emissions for each unit are based on either CEMS data, source test results, or for SOx, the default emission factor. The following tables summarize the data.

Table G.1 Existing Boilers Emission Factors for Determination of Past Actual Emissions

Pollutant	Boiler 1 Emission Factor	Source	Boiler 2 Emission Factor	Source
NOx	Based on quarterly reports			
VOC	1.64 lbs/mmscf	12/18/11 source test	0.9 lbs/mmscf	11/14/12 source test
CO	0.274 lbs/mmbtu	Average of the 12/11/07 & 4/7/10 source tests for Boiler 1 & 4/6/10 source test for Boiler 2	0.274 lbs/mmbtu	Average of the 12/11/07 & 4/7/10 source tests for Boiler 1 & 4/6/10 source test for Boiler 2
SOx	0.83 lbs/mmscf	AQMD Form B-1 factor	0.83 lbs/mmscf	AQMD Form B-1 factor
PM10	1.86 lbs/mmscf	11/14/12 source test	2.1 lbs/mmscf	11/14/12 source test
CO2	53.06 kg/mmbtu	EPA	53.06 kg/mmbtu	EPA

Table G.2 Boiler #1 Past Actual Emissions

Year	Month	Fuel Use		VOC	CO	NOx	SOx	PM10	CO2
		mmscf	mmbtu	lbs	lbs	lbs	lbs	lbs	tons
2011	1	62.763	60,156	96.3	16482.8	444.53	48.7	109.2	3519.0
	2	0	0	0.0	0.0	0	0.0	0.0	0.0
	3	6.074	7,373	11.9	2020.3	1312.12	6.0	13.5	431.3
	4	400.181	413,469	664.0	113290.5	2494.6	336.1	753.1	24187.4
	5	283.706	290,452	467.5	79583.9	4987.65	236.6	530.2	16991.1
	6	440.604	451,166	726.1	123619.6	5510.48	367.5	823.5	26392.6
	7	633.652	648,876	1039.8	177791.9	3892.44	526.3	1179.3	37958.4
	8	409.049	418,914	671.4	114782.3	3641.22	339.8	761.4	24505.9
	9	307.224	314,013	503.2	86039.5	2504.27	254.6	570.7	18369.3
	10	114.327	117,214	187.5	32116.6	968.99	94.9	212.7	6856.9
	11	112.735	115,873	185.8	31749.2	1293.79	94.0	210.7	6778.4
	12	42	43	0.1	11.8	0.27	0.0	0.1	2.5
	Total	2,770.357	2,837,549	4,554	777,488	27,050	2,305	5,164	165993

2012	1	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0
	2	161.435	166,143	264.8	45578.5	7418.61	134.0	300.3	9719.1
	3	105.458	108,533	173.0	29774.3	2794.12	87.5	196.2	6349.0
	4	350.268	557,829	888.9	153031.2	3796.91	449.9	1008.2	32632.2
	5	351.224	424,521	676.5	116460.2	5655.08	342.4	767.2	24833.9
	6	305.425	474,294	755.8	130114.6	7262.46	382.5	857.2	27745.6
	7	289.921	192,818	307.3	52896.4	9010.13	155.5	348.5	11279.6
	8	494.545	433,370	690.6	118887.8	8257.04	349.5	783.2	25351.6
	9	571.910	390,080	621.6	107012.0	6466.24	314.6	705.0	22819.2
	10	78.190	80,470	128.2	22075.7	417.97	64.9	145.4	4707.4
	11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	12	133.084	0.0	218.3	37574.1	1118.87	110.5	247.5	0.0
	Total	5,750.375	2,828,058	4,725	813,405	52,197	2,391	5,359	165438
	Ave	4,260.366	2,832,804	4,640	79,5447	39,624	2,348	5,262	165716
2013	1	199.18	209,140	326.66	57304.31	1,928.57	165.32	370.48	12234.4
	2	467.58	490,963	766.84	134523.7	3,578.45	388.09	869.71	28720.7
	3	196.80	206,644	322.76	56620.4	1,218.43	163.35	366.05	12088.4
	4	114.90	120,649	188.44	33057.74	1,413.80	95.37	213.72	7057.8
	5	296.83	311,671	486.80	85397.91	1,915.94	246.37	552.10	18232.3
	6	307.18	322,542	503.78	88376.37	2,179.05	254.96	571.36	18868.3
	7	323.14	339,302	529.96	92968.75	1,846.28	268.21	601.05	19848.7
	8	344.79	362,035	565.46	99197.48	1,699.16	286.18	641.32	21178.6
	9	269.30	282,766	441.65	77477.75	1,268.28	223.52	500.90	16541.4
	10	181.65	190,735	297.91	52261.31	1,397.69	150.77	337.87	11157.7
	11	322.22	338,328	528.44	92701.82	2,302.05	267.44	599.32	19791.7
	12	462.50	485,630	758.51	133062.6	2,994.67	383.88	860.26	28408.7
	Total	3,486	3,660,402	5,717	1,002,950	27,742	2,893	6,484	214129
	Ave	4,618	3,244,230	5,221	908,178	37,970	2,642	5,922	189784
2014	1	344.68	361,909	565.27	99,163.18	2,255.95	286.08	641.10	21171.2
	2	92.91	97,555	152.37	26729.93	593.61	77.11	172.81	5706.8
	3	490.97	515,520	805.19	141252.5	2,584.59	407.51	913.21	30157.2
	4	424.37	445,590	695.97	122091.8	2,647.54	352.23	789.33	26066.4
	5	338.24	355,153	554.72	97311.98	2,246.73	280.74	629.13	20776.0
	6	332.66	349,292	545.56	95705.98	2,477.90	276.11	618.75	20433.1
	7	620.64	651,677	1017.86	178559.4	5,443.45	515.13	1154.40	38122.2
	8	599.45	629,421	983.10	172461.3	4,423.83	497.54	1114.97	36820.3
	9	544.96	572,206	893.73	156784.4	3,777.74	452.32	1013.62	33473.3
	10	342.50	359,624	561.70	98536.95	2,507.04	284.27	637.05	21037.5
	11	67.16	70,517	110.14	19321.77	574.33	55.74	124.92	4125.1
	12	72.63	76,260	119.11	20895.32	728.59	60.28	135.09	4461.1
	Total	4,271	4,484,724	7,005	1,228,814	30,261	3,545	7,994	262350
	Ave	3,879	4,072,563	6,361	1,115,882	27,002	3,219	7,239	238240
2015	1	404.20	424,410	662.89	116288.3	3,186.09	335.49	751.81	24827.4
	2	0	0	0.00	0	0.00	0.00	0.00	0.0
	3	218.58	229,510	358.47	62885.82	1,954.70	181.42	406.56	13426.0
	4	81.94	86,041	134.39	23575.34	677.00	68.01	152.42	5033.3
	5	185.96	195,259	304.98	53500.99	1,757.67	154.35	345.89	11422.4
	6	494.00	518,698	810.16	142123.4	3,815.33	410.02	918.84	30343.1

	7	552.61	580,237	906.27	158984.8	4,014.53	458.66	1027.85	33943.1
	8	583.09	612,247	956.27	167755.7	4,205.11	483.97	1084.55	35815.6
	9	534.20	560,914	876.09	153690.3	3,958.25	443.39	993.62	32812.7
	10	378.05	396,949	620.00	108763.9	3,549.52	313.78	703.17	23221.0
	11	88.78	93,216	145.59	25541.13	999.49	73.68	165.13	5453.0
	12	231.83	243,426	380.21	66698.67	1,757.06	192.42	431.21	14240.1
	Total	3,753	3,940,906	6,155	1,079,808	29,875	3,115	6,981	230538
	Ave	4,012	4,212,815	6,580	1,154,311	30,068	3,330	7,488	246444

Average based on previous 2 years

Table G.3 Boiler #2 Past Actual Emissions

Year	Month	Fuel Use		VOC	CO	NOx	SOx	PM10	CO2
		mmscf	Mmbtu	lbs	lbs	lbs	lbs	lbs	tons
2011	1	14.056	13,472	11.8	3691.3	185.47	10.9	27.6	788.1
	2	106.169	101,824	89.8	27899.8	1500.59	82.8	209.5	5956.6
	3	278.364	337,906	299.0	92586.2	1777.49	275.7	697.6	19767.0
	4	37.870	39,127	34.5	10720.9	274.72	31.8	80.5	2288.9
	5	22.156	22,683	20.0	6215.1	333.27	18.5	46.7	1326.9
	6	250.102	256,098	226.2	70170.7	2667.85	208.6	527.7	14981.4
	7	547.540	560,695	493.1	153630.4	3952.23	454.7	1150.6	32799.9
	8	552.538	565,863	497.7	155046.5	5011.13	459.0	1161.2	33102.2
	9	402.546	411,441	361.8	112734.9	5205.98	333.7	844.2	24068.7
	10	287.825	295,093	259.1	80855.5	2764.63	239.0	604.6	17262.5
	11	261.011	268,277	236.1	73507.9	3899.59	217.7	550.8	15693.8
	12	328.531	340,574	298.4	93317.4	4236.25	275.2	696.3	19923.1
	Total	3,088.708	3,213,053	2,828	880,377	31,809	2,608	6,597	187959
2012	1	368.745	379,499	331.9	104109.1	4899.35	306.1	774.4	22200.2
	2	576.575	593,390	518.9	162786.6	5543.86	478.6	1210.8	34712.5
	3	700.052	720,468	630.0	197648.4	7185.58	581.0	1470.1	42146.4
	4	123.418	196,553	171.9	53921.2	1430.62	158.5	401.1	11498.1
	5	583.942	705,805	617.2	193625.9	5097.79	569.2	1440.2	41288.6
	6	468.252	727,148	635.9	199480.8	5817.53	586.4	1483.7	42537.2
	7	443.085	294,683	257.7	80841.2	7953.6	237.7	601.3	17238.6
	8	603.752	529,068	462.7	145141.0	7549.64	426.7	1079.6	30949.8
	9	595.486	406,160	355.2	111423.3	6371.91	327.6	828.8	23759.8
	10	558.382	574,666	502.5	157650.1	2535.32	463.5	1172.6	33617.2
	11	412.050	424,067	370.8	116335.6	2259.07	342.0	865.3	24807.3
	12	316.606	325,839	284.9	89388.6	2775.45	262.8	664.9	19061.1
	Total	5750.345	5,877,346	5,139.6	1,612,351.8	59,419.72	4,740.1	11,992.8	343817
	Ave	4,419.527	4,545,200	3,984	1,246,364	45,614	3,674	9,295	265888
2013	1	508.25	533,662	457.42	146223.3	2,533.56	421.85	1067.32	31218.5
	2	600.63	630,664	540.57	172801.8	2,959.25	498.52	1261.33	36893.0
	3	512.17	537,783	460.96	147352.7	2,537.59	425.10	1075.57	31459.6
	4	178.34	187,258	160.51	51308.66	1,683.98	148.02	374.52	10954.3
	5	513.69	539,377	462.32	147789.4	2,991.66	426.36	1078.75	31552.8

	6	446.02	468,318	401.42	128319.2	2,892.26	370.19	936.64	27396.0
	7	597.57	627,451	537.82	171921.6	3,173.67	495.99	1254.90	36705.0
	8	724.55	760,783	652.10	208454.4	3,056.39	601.38	1521.57	44504.8
	9	530.87	557,416	477.78	152731.9	2,645.23	440.62	1114.83	32608.1
	10	168.77	177,203	151.89	48553.73	1,203.35	140.08	354.41	10366.1
	11	398.92	418,863	359.03	114768.4	2,540.20	331.10	837.73	24502.9
	12	130.09	136,600	117.09	37428.26	1,079.85	107.98	273.20	7990.9
	Total	5,310	5,575,377	4,779	1,527,653	29,297	4,407	11,151	326152
	Ave	5,330	5,726,362	4,959	1,570,002	44,358	4,574	11,572	334985
2014	1	70.77	74,308	63.69	20360.42	455.91	58.74	148.62	4346.9
	2	83.52	87,699	75.17	24029.44	528.73	69.32	175.40	5130.3
	3	219.43	230,400	197.49	63129.57	1,465.27	182.13	460.80	13478.1
	4	155.26	163,024	139.73	44668.49	1,123.73	128.87	326.05	9536.7
	5	259.35	272,317	233.41	74614.97	1,923.64	215.26	544.63	15930.2
	6	478.54	502,469	430.69	137676.5	3,157.34	397.19	1004.94	29393.8
	7	636.19	667,997	572.57	183031.1	3,946.20	528.04	1335.99	39076.9
	8	701.74	736,830	631.57	201891.4	4,593.78	582.45	1473.66	43103.6
	9	760.94	798,991	684.85	218923.4	5,083.86	631.58	1597.98	46739.9
	10	771.84	810,433	694.66	222058.8	4,868.91	640.63	1620.87	47409.2
	11	563.02	591,176	506.72	161982.2	3,511.95	467.31	1182.35	34583.0
	12	381.77	400,856	343.59	109834.4	2,266.17	316.87	801.71	23449.5
	Total	5,082	5,336,499	4,574	1,462,201	32,925	4,218	10,673	312178
	Ave	5,196	5,455,938	4,677	1,494,927	31,111	4,313	10.912	319165
2015	1	0.19	195	0.17	53.3204	4.53	0.15	0.39	11.4
	2	0	0	0.00	0	0.00	0.00	0.00	0.0
	3	298.95	313,897	269.05	86007.72	2,046.53	248.13	627.79	18362.6
	4	158.92	166,866	143.03	45721.26	1,399.00	131.90	333.73	9761.4
	5	130.24	136,757	117.22	37471.45	1,018.57	108.10	273.51	8000.1
	6	361.20	379,263	325.08	103918	3,203.22	299.80	758.53	22186.4
	7	512.35	537,969	461.12	147403.4	3,930.13	425.25	1075.94	31470.5
	8	629.81	661,302	566.83	181196.7	4,522.98	522.74	1322.60	38685.3
	9	549.81	577,299	494.83	158179.8	4,105.33	456.34	1154.60	33771.2
	10	445.31	467,571	400.77	128114.3	3,511.15	369.60	935.14	27352.3
	11	351.70	369,281	316.53	101183	3,394.97	291.91	738.56	21602.4
	12	435.97	457,764	392.37	125427.3	3,315.71	361.85	915.53	26778.6
	Total	3,874	4,068,162	3,487	1,114,676	30,452	3,216	8,136	237982
	Ave	4,478	4,702,331	4,031	1,288,439	31,689	3,717	9,405	275080

Average based on previous 2 years

Appendix H

Modeling

The proposed projects will result in the release of 5 criteria pollutants plus toxics. Modeling is required to determine the impacts on ambient air quality and visibility from the release of NOx, SOx, CO, and PM10. Also, a health risk assessment is required for toxics. Modeling for the criteria pollutant impacts was conducted based on both an individual and combined basis from the 4 new turbines and auxiliary boiler, and on an individual equipment basis for the HRA.

Meteorological data from the John Wayne airport station was used. Although the District's Costa Mesa meteorological station is closer to the project site, the data from the John Wayne airport station was deemed appropriate for this project because of the following factors:

a) Surface characteristics at John Wayne airport are more similar to the project site
b) John Wayne airport data is more current
c) John Wayne airport has less missing data
d) Costa Mesa data is problematic

Background concentrations were determined using the Costa Mesa station data, except for PM10 and PM2.5, which is from the Mission Viejo station.

The stack parameters and emission rates used in the modeling, and the model results are summarized in the following tables:

Criteria Pollutant Modeling

Start Up/Shutdown and Normal Operations

A screening level model was performed for 41 different load/ambient temperature/exhaust conditions as shown in Tables 1A and 1B.

Table H.2 outlines the stack locations and dimensions. Location and elevation is in reference to UTM North American Datum 1983 Zone 11 coordinate system.

Tables H.3A, H.3B, H.3C, and H.3D outline the emission rates used in the models. Note that the 1 hour NO2 and CO model runs assume the CCTG in cold start up and the SCTG undergoing 1 start, 1 shutdown, and the remainder of the hour at full load steady state conditions. The 8 hour CO model run assumes the CCTG undergoes 2 cold star ts, 2 shutdowns, and the remainder of the 8 hours at full load steady state conditions, and the SCTG undergoes 2 starts, 2 shutdowns, and the remainder of the

8 hours at full load steady state conditions. All PM10 and SOx runs assume full load steady state conditions, except the annual PM10 model run.

The annual NO2 and PM10 is based on 80 cold starts, 88 warm starts, 332 hot starts, 500 shutdowns, and 6,100 hours at full load steady state conditions at 65.8°F for the CCTG, 350 start ups, 350 shutdowns and 1,750 hours at full load steady state conditions at 65.8 °F for the SCTG, and 12 start ups and an annual heat input of 189,155 mmbtu for the auxiliary boiler.

Table H.1A
CCTG and SCTG Load Analysis

		CCTG			SCTG		
Temp	Scenario	Load	Exhaust Temp	Exit Velocity	Load	Exhaust Temp	Exit Velocity
32 °F	1	Max	375	20.4	Max	694	33.3
	2	Max	375	20.4	Ave	709	28.7
	3	Max	375	20.4	Min	748	23.8
	4	Ave	354	15.6	Max	694	33.3
	5	Ave	354	15.6	Ave	709	28.7
	6	Ave	354	15.6	Min	748	23.8
	7	Min	350	12.2	Max	694	33.3
	8	Min	350	12.2	Ave	709	28.7
	9	Min	350	12.2	Min	748	23.8
65.8 °F	10	Max w evap	374	20.1	Max w evap	697	33.1
	11	Max w evap	374	20.1	Max	699	33.0
	12	Max w evap	374	20.1	Ave	709	28.4
	13	Max w evap	374	20.1	Min	748	23.6
	14	Max	375	20.2	Max w evap	697	33.1
	15	Max	375	20.2	Max	699	33.0
	16	Max	375	20.2	Ave	709	28.4
	17	Max	375	20.2	Min	748	23.6
	18	Ave	353	14.9	Max w evap	697	33.1
	19	Ave	353	14.9	Max	699	33.0
	20	Ave	353	14.9	Ave	709	28.4
	21	Ave	353	14.9	Min	748	23.6
	22	Min	350	11.8	Max w evap	697	33.1
	23	Min	350	11.8	Max	699	33.0
	24	Min	350	11.8	Ave	709	28.4
	25	Min	350	11.8	Min	748	23.6
110 °F	26	Max w evap	378	20.2	Max w evap	726	29.4
	27	Max w evap	378	20.2	Max	746	27.1
	28	Max w evap	378	20.2	Ave	769	23.7
	29	Max w evap	378	20.2	Min	809	20.0
	30	Max	379	18.0	Max w evap	726	29.4
	31	Max	379	18.0	Max	746	27.1
	32	Max	379	18.0	Ave	769	23.7
	33	Max	379	18.0	Min	809	20.0
	34	Ave	365	13.9	Max w evap	726	29.4

	35	Ave	365	13.9	Max	746	27.1
	36	Ave	365	13.9	Ave	769	23.7
	37	Ave	365	13.9	Min	809	20.0
	38	Min	358	12.1	Max w evap	726	29.4
	39	Min	358	12.1	Max	746	27.1
	40	Min	358	12.1	Ave	769	23.7
	41	Min	358	12.1	Min	809	20.0

The Auxiliary Boiler was included in each run with the following parameters:

Table H.1B
Auxiliary Boiler

Temp, °F	Scenario	Load	Exhaust Temp, K	Exit Velocity, m/s
32/65.8/110	1-41	Max	432	21.2

Table H.2
Stack Locations and Dimensions All Sources

Equipment	Easting (m)	Northing (m)	Base Elevation (m)	Stack Ht (m)	Stack Dia (m)
7FA.05	409449	3723148	3.66	45.7	6.10
7FA.05	409474	3723182	3.66	45.7	6.10
LMS-100	409149	3723193	3.66	24.4	4.11
LMS-100	409185	3723168	3.66	24.4	4.11
Auxiliary Boiler	409438	3723236	3.66	24.4	0.91

Table H.3A
Short Term Emission Rates CCTG

Temp	1-Hour NO2 (lbs/hr)	1-Hour CO (lbs/hr)	8-Hour CO (lbs/hr)				1-Hour/3-Hour/24 Hour SOx (lbs/hr)				24-Hour PM10/PM2.5 (lbs/hr)
	All Loads	All Loads	Max*	Max	Ave	Min	Max*	Max	Ave	Min	All Loads
32	61.0	325	//////	121	119	118	//////	4.86	3.84	2.95	8.5
65.8	57.0	287	108	108	106	105	4.81	4.78	3.72	2.79	8.5
110	53.0	220	85.1	84.5	83.5	82.7	4.60	4.16	3.33	2.67	8.5

** With evaporative cooling*

Table H.3B
Short Term Emission Rates SCTG

Temp	1-Hour NO2 (lbs/hr)				1-Hour CO (lbs/hr)				8-Hour CO (lbs/hr)				1-Hour/3-Hour/24 Hour SOx				PM10
	Max*	Max	Ave	Min	Max*	Max	Ave	Min	Max*	Max	Ave	Min	Max*	Max	Ave	Min	All
32	//////	22.0	21.6	21.2	//////	45.8	45.3	44.9	//////	17.5	16.2	15.0	//////	1.63	1.32	1.02	6.24
65.8	22.1	22.0	21.6	21.2	45.8	45.7	45.3	44.9	17.5	17.4	16.2	15.0	1.64	1.61	1.31	1.01	6.24
110	21.7	21.5	21.2	20.9	45.4	45.2	44.9	44.6	16.4	15.8	15.0	14.1	1.36	1.22	1.01	0.80	6.24

** With evaporative cooling*

Table H.3C
Long Term Emission Rates CCTG and SCTG

Temp 65.8°F	Annual NOx (lbs/hr)				Annual PM10/PM2.5 (lbs/hr)
	Max*	Max	Ave	Min	All Loads
CCTG	13.2	13.1	10.5	8.38	6.42
SCTG	2.44	2.42	2.11	1.81	1.43

** With evaporative cooling*

Table H.3D
Emission Rates Auxiliary Boiler

1-Hour NO2 (lbs/hr)	1-Hour CO (lbs/hr)	8-Hour CO (lbs/hr)-	1-Hour/3-Hour SOx (lbs/hr)	24 hour SOx (lbs/hr)	24-Hour PM10/PM2.5 (lbs/hr)	Annual NOx (lbs/hr)	Annual PM10/PM2.5 (lbs/hr)
0.42	2.83	2.37	0.048	0.025	0.157	0.15	0.15

Table H.4
Model Results – Start up/Shutdown and Normal Operation (all 5 stacks combined)

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Concentration (ug/m3)
NO2	1-hour	95	142	237
	1-hour Federal	27.8	98.2	126
	Annual	0.59	21.8	22.4
CO	1-hour	631	3,435	4,066
	8-hour	149	2,519	2,668
SO2	1-hour	5.76	23.1	28.9
	1-hour Federal	5.4	23.1	28.5
	3-hour	5.01	23.1	28.2
	24-hour	1.66	5.2	6.86
PM10	24-hour	4.7	51.0	55.7
	Annual	0.6	19.3	19.9
PM2.5	24-hour Federal	4.7	21.3	26
	Annual	0.6	8.6	9.2

The maximum 1 hour and annual NO2 concentrations include ambient NO2 ratios of 0.80 and 0.75 respectively.

Background concentrations for NO2, CO, and SO2 are the maximum recorded values for the Costa Mesa monitoring station, and for PM10 and PM2.5 maximum recorded values from the Mission Viejo monitoring station, during the years 2011-2014, except for Federal 1-hour NO2, and 24-hour PM2.5 which the background concentration is based on the 98th percentile of the 3-year average, and for Federal 1-hour SO2, which the background concentration is based on the 99th percentile of the 3-year average (however, since the 3 most recent years were not available for SO2, the maximum 1-hour concentration was used instead).

Commissioning

Six short term scenarios were modeled as shown in Table 5. Annual emissions were also modeled. The annual scenarios are shown in Table 6 and include 1) commissioning of the CCTGs with the balance of the year in normal operation (no SCTG operation), and 2) commissioning of the SCTGs with the balance of the year in normal operation, as well as the CCTG's in start up operation. All scenarios include the auxiliary boiler with emissions as shown in Table 3D and exhaust parameters as shown in Table 1B.

Table H.5
Commissioning Short Term Modeled Scenarios and Emission Rates

Turbine Operating Scenario	Pollutant	Averaging Period	Emissions Per Turbine, lbs/hr	
			Commissioning	Start Up
2 CCTG undergoing commissioning at 10% load	NOx	1-hour	130	//////
	CO	1-hour	1900	//////
		8-hour	1900	//////
2 CCTG undergoing commissioning at 40% load	NOx	1-hour	68.3	//////
2 CCTG undergoing commissioning at 80% load	NOx	1-hour	63.0	//////
2 SCTG undergoing commissioning at 5% load with 2 CCTG in cold start up	NOx	1-hour	40.1	61.0
	CO	1-hour	244	325
		8-hour	244	95.2
2 SCTG undergoing commissioning at 75% load with 2 CCTG in cold start up	CO	1-hour	72.5	325
		8-hour	72.5	95.2

2 SCTG undergoing commissioning at 100% load with 2 CCTG in cold start up	CO	1-hour	90.0	325
		8-hour	90.0	95.2

Table H.6
Commissioning Long Term Scenarios and Emission Rates

Turbine Operating Scenario	Averaging Time	Pollutant	Emissions Per Turbine, lbs/hr	
			CCTG	SCTG
2 CCTG commissioned with balance of year in normal operation	Annual	NOx	11.5	///////
		PM10/PM2.5	7.38	//////
2 SCTG commissioned with balance of year in normal operation and 2 CCTG in start up operation	Annual	NOx	8.12	2.76
		PM10/PM2.5	6.42	1.63

Table H.7
Commissioning Stack Parameters

Turbine Operating Scenario	Stack Temp, K	Exhaust Velocity, m/s
CCTG 10% Load	361	9.33
CCTG 40% Load	359	11.9
CCTG 80% Load	366	16.1
CCTG Annual	350	12.2
SCTG 5% Load	728	10.0
SCTG 75% Load	694	33.3
SCTG 100% Load	748	23.8

Table H.8
Model Results – CCTG Commissioning

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Concentration (ug/m3)
NO2	1-hour	169	142	311
	Annual	0.66	21.8	22.5
CO	1-hour	4,341	3,435	7,776
	8-hour	3,000	2,519	5,519
PM10	Annual	0.57	19.3	19.9
PM2.5	Annual	0.57	8.6	9.2

Table H.9
Model Results – SCTG Commissioning

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Concentration (ug/m3)
NO2	1-hour	79.1	142	221
	Annual	0.50	21.8	22.3
CO	1-hour	527	3,435	3,962
	8-hour	131	2,519	2,650
PM10	Annual	0.52	19.3	19.8
PM2.5	Annual	0.52	8.6	9.1

PSD

- Ambient Air Quality Impacts

The results of the operational impacts modeling were compared to the Class II significance impact levels (SILs), PSD Calls II Increment Standards, and Significant Monitoring Concentration. The model for 24 hour PM10 was re-run assuming 1 CCTG operating at minimum load for 20 hours, and average load for 4 hours, while the other CCTG operating at minimum load for 24 hours, with both SSTG operating at 50% load, and the AB operating at full load (assuming both CCTG's operating 24 hours at minimum load results in an impact greater than the SIL, see Table 4).

Table H.10
Model Inputs for 24 Hour PM10 for Comparison to PSD Thresholds

Source	Emission Rate, lbs/day	Stack Temp, K	Exhaust Velocity, m/s
CCTG 1 (20 hrs @44% Load)[1]	170	350	11.8
CCTG 1 (4 hrs @ 75% Load)[1]	34	353	14.9
CCTG 2 (24 hrs @44% Load)[1]	204	353	14.9
SCTG 1 (24 hrs @50% Load)	150	748	23.6
SCTG 2 (24 hrs @50% Load)	150	748	23.6
AB 100% Load	3.77	432	21.2

1 One CCTG assumed to operate at 44% load for 20 hrs/day and 75% load for 4 hrs/day, the other CCTG assumed to operate 24 hrs/day at 44% load. Both turbines were not assumed to operate at 44% load for 24 hours because this is an unlikely scenario.

Table H.11
Comparison of Modeled Results to PSD Significance Thresholds

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	PSD Class II Increment Standard (ug/m3)	Significant Monitoring Concentration (ug/m3)
NO2	1-hour	95	7.52	////////	////////
	Annual	0.59	1.0	25	14
CO	1-hour	631	2,000	////////	////////
	8-hour	149	500	////////	575
PM10	24-hour	4.7	5.0	30	10
	Annual	0.6	1.0	17	////////

The results show that the facility is required to conduct a cumulative modeling analysis for 1 hour NO2 since the operational impact is greater than the Class II SIL of 7.5 ug/m3. Tables 11A and 11B show the sources included in the cumulative analysis:

Table H.11A
Cumulative Analysis Stack Parameters and Emission Rates, Point Sources

Facility	Source	Emission Rate	Easting	Northing	Base Elevation	Stack Ht	Stack Dia	Stack Temp	Exit Velocity
		(Lbs/hr)	(m)	(m)	(m)	(m)	(m)	(K)	(m/s)
HBEP	CCTG 1	57.0	409449	3723146	3.66	45.7	6.10	350	11.8
	CCTG 2	57.0	409474	3723182	3.66	45.7	6.10	350	11.8
	SSTG 1	21.2	409149	3723193	3.66	24.4	4.11	748	23.6
	SSTG 2	21.2	409185	3723168	3.66	24.4	4.11	748	23.6
	AuxBoiler	0.42	409438	3723236	3.66	24.4	0.91	432	21.2
	Boiler 1	34.3	409274	3723095	3.66	61.0	6.27	367	7.90
OC Sanitation Fountain Valley	1730101	5.17	412962	3728359	8.00	7.41	2.23	1089	1.37
	1730102	0.08	412914	3728328	7.70	7.62	0.55	475	7.03
	1730103	7.78	412935	3728401	8.00	18.9	0.76	533	17.9
	1730104	7.78	412942	3728391	8.00	18.9	0.76	533	17.9
	1730105	7.78	412939	3728396	8.00	18.9	0.76	533	17.9
OC Sanitation Huntington Beach	2911001	0.6	411071	3722213	1.60	7.62	0.53	475	7.44
	2911002	0.87	411096	3722214	1.60	7.41	0.68	1089	1.37
	2911003	6.90	411240	3722455	1.60	18.0	0.76	589	22.9
	2911004	6.90	411248	3722455	1.60	18.0	0.76	589	22.9
	2911005	6.90	411255	3722455	1.60	18.0	0.76	589	22.9
	2911006	6.90	411263	3722455	1.60	18.0	0.76	589	22.9
	2911007	6.90	411270	3722455	1.60	18.0	0.76	589	22.9
BETA Offshore	16607301	15.1	395222	3716431	0	18.3	0.30	661	31.1
	16607302	15.1	395222	3716431	0	18.3	0.30	641	30.0
	16607303	15.1	395222	3716431	0	18.3	0.30	585	24.2
	16607304	15.1	394082	3717932	0	18.3	0.30	663	28.7
	16607305	15.1	394082	3717932	0	18.3	0.30	684	34.7
	16607306	15.1	394082	3717932	0	18.3	0.30	583	21.1
	16607307	2.94	395265	3716544	0	18.3	0.61	671	39.4
	16607308	2.46	395265	3716544	0	18.3	0.61	671	38.1
	16607309	2.78	395265	3716544	0	18.3	0.61	677	37.5
	16607310	20.0	395265	3716544	0	18.3	0.76	671	81.2
	16607311	19.7	395265	3716544	0	18.3	0.76	669	81.1
	16607312	19.7	395265	3716544	0	18.3	0.76	668	81.4
	16607313	81.6	395265	3716544	0	22.9	0.51	464	8.35

Table H.11B
Cumulative Analysis Stack Parameters and Emission Rates, Volume Sources

Facility	Source ID	Emission Rate	Base Elevation	Release Ht	Initial Horizontal Dimension	Initial Vertical Dimension
		(Lbs/hr)	(m)	(m)	(m)	(m)
Shipping Lanes (total for 525 sources)	734601-774425	202	0	0	186	23.3

Table H.12
Cumulative Analysis Results

Source/Year	2010	2011	2012	2013	2014
HBEP	75.4	71.0	73.2	74.1	76.0
HBGS	5.15	5.08	5.32	5.12	4.73
OCSFV	8.92	8.92	8.87	8.91	9.02
OCSHB	56.2	54.0	54.1	54.1	53.7
BETA	58.2	63.2	62.6	66.8	66.1
SHIPS	24.3	23.4	23.9	22.6	23.3
TOTAL PLUS BACKGROUND	140	147	148	143	144

The modeled concentration is the 8th high result. Model result is added to the 98th percentile seasonal hour-of-day background concentration for 2010 through 2012 to obtain total concentration.

- Class I Deposition and Visibility Analysis

Actual ambient air quality impacts at Class I areas were not determined. The nearest Class I areas to the project site are the Cucamonga Wilderness and the San Gabriel Wilderness, both 69 km away.

The applicant determined the following maximum predicted impacts for the project at 50 km.

Table H.13
Predicted Impacts at 50 km (all 5 stacks combined)

Pollutant	Averaging Time	Maximum Modeled Concentration at 50 km (ug/m3)	Significant Impact Level (ug/m3)	PSD Class I Increment Standard (ug/m3)
NO2	Annual	0.0057	0.1	2.5
PM10	24-hour	0.042	0.3	2.0
	Annual	0.0057	0.2	1.0

The analysis used the emission rates and stack parameters from Tables 1A, 1B, 2, 3A, 3B, 3C, and 3D which result in the worst case impacts for each source/pollutant/averaging time.

Since the impacts are all less than the SIL and Class I Increment Standard, the applicant concluded that the impacts at the more distant Class I areas would be negligible (AFC page 5.1-19 and Table 5.1-27).

A full visibility and deposition analysis for Class I areas was not conducted under PSD. The applicant cited a screening criteria under FLAG 2010 which states that for sources > 50km from a Class I area, if Q/D is < 10, no analysis is required. Q is the sum of the annual NOx, SO2, H2SO4, and PM10 in tons from the project, estimated to be 420 tpy. D would be the distance in km to the nearest Class I area (in this case Cucamonga and San Gabriel Wilderness at 69 km). Approximate Q/D is 6.1.

- Class II Visibility Analysis

A visibility analysis was conducted on nearby Class II areas using VISCREEN. Most areas were shown to meet the color difference and contrast criteria using a Level I analysis. Because Crystal Cove State Park and Huntington Beach State Park results were greater than the criteria levels (Color Difference -2, Contrast – 0.05), they were further analyzed using a Level II analysis. Crystal Cove results were less than the criteria thresholds using the Level II analysis, while Huntington Beach State Park results were above the criteria thresholds.

Table 14 shows the emission rates used in the analysis, Tables 15A and 15B show the results.

Table H.14
VISCREEN Emission Rates

Pollutant	Emissions, tpy
NO2	136
PM10	69.4

Table H.15A
Class II Level I Visibility Results

Class II Area	Variable	Sky	Terrain
Crystal Cove	Color	2.510	5.419
	Contrast	0.03	0.029
Water Canyon	Color	1.11	1.658
	Contrast	0.013	0.014
Chino Hills State Park	Color	0.912	1.525
	Contrast	0.011	0.014
San Mateo Canyon Wilderness Area	Color	0.703	1.113
	Contrast	0.008	0.011

Note:
Criteria Levels for Class I areas:
Color Difference – 2
Contrast – 0.05

Table H.15B
Class II Level II Visibility Results

Class II Area	Stability Class	Variable	Sky	Terrain
Crystal Cove	D	Color	0.265	0.644
		Contrast	0.003	0.003
Huntington Beach State Park	A	Color	7.889	/////////
		Contrast	0.139	/////////
	B	Color	10.162	/////////
		Contrast	0.182	/////////
	C	Color	5.976	/////////
		Contrast	0.076	/////////
	D	Color	7.659	/////////
		Contrast	0.098	/////////

Note:
Criteria Levels for Class I areas:
Color Difference – 2
Contrast – 0.05

Health Risk Assessment

Air Toxics Health Risk Assessment (HRA)

A Tier 4 HRA was performed for the project using CARB's Hotspots Analysis and Reporting Program (HARP 2).

Table H.16
Modeled Stack Parameters for HRA

Source	Load[1], %	Stack Temp, K	Exhaust Velocity, m/s
CCTG	44	350	11.8
SCTG	50	748	23.6
AB	///////////	432	21.2

1 The load percentage is only used to determine stack parameters, not emission rates. Emission rates are based on 100% load, see Tables 17 and 18.

Table H.17
Gas Turbine Toxic Emission Rates

Pollutant	Emission Factor	Emissions per CCTG Turbine(1)		Emissions per SCTG Turbine(2)	
	lbs/mmbtu	lbs/hr	lbs/yr	lbs/hr	lbs/yr
Ammonia	5 ppm	15.2	100,928	6.14	12,286
Acetaldehyde	1.71E-04	3.89E-01	2552.5	1.51E-01	212.0
Acolein	3.51E-06	7.98E-03	52.4	3.11E-03	4.4
Benzene	3.17E-06	7.21E-03	47.3	2.81E-03	3.9
1,3 Butadiene	4.18E-07	9.50E-04	6.2	3.70E-04	0.5
Ethyl Benzene	3.11E-05	7.07E-02	464.2	2.75E-02	38.6
Formaldehyde	3.50E-04	7.96E-01	5224.4	3.10E-01	434.0
Naphthalene	1.26E-06	2.86E-03	18.8	1.12E-03	1.6
PAH	8.74E-07	1.99E-03	13.0	7.73E-04	1.1
Propylene Oxide	2.82E-05	6.41E-02	420.9	2.50E-02	35.0
Toluene	1.26E-04	2.86E-01	1880.8	1.12E-01	156.2
Xylene	6.22E-05	1.41E-01	928.4	5.50E-02	77.1

(1) Hourly emission rates based on 2,273 mmbtu/hr (maximum heat input at low temp), annual emission rates based on 2,248 mmbtu/hr (heat input annual average temp) and 6,640 hours/yr operation (6,100 hours normal operation plus 500 start ups and shutdowns)
(2) hourly and annual emission rates based on 885 mmbtu/hr and 2001 hours/yr operation (1,750 hours normal operation and 350 start ups and shutdowns)

Table H.18
Auxiliary Boiler Toxic Emission Rates

Pollutant	Emission Factor	Emissions(1)	
	lbs/mmbtu	lbs/hr	lbs/yr
Benzene	5.52E-06	3.91E-04	1.04E+00
Formaldehyde	1.17E-05	8.29E-04	2.21E+00
PAHs	9.52E-08	6.74E-06	1.80E-02
Naphthalene	2.86E-07	2.02E-05	5.41E-02
Acetaldehyde	2.95E-06	2.09E-04	5.58E-01
Acrolein	2.57E-06	1.82E-04	4.86E-01
Toluene	2.52E-05	1.79E-03	4.77E+00
Xylene	1.88E-05	1.33E-03	3.56E+00
Ethylbenzene	6.57E-06	4.65E-04	1.24E+00
Hexane	4.38E-06	3.10E-04	8.28E-01

(1) Hourly emission rates based on 71 mmbtu/hr, annual emission rates based on 189,155 mmbtu/hr

Table H.19A
Model Results – HRA CCTG (individual unit)

Receptor	Cancer Risk Per Million	Chronic Hazard Index	Acute Hazard Index
Maximum Impact	2.38	0.0060	0.032
MEIR	1.36	0.0035	0.0090
MEIW	0.086	0.0060	~~0.091~~ **0.032**
Sensitive receptor	0.74	0.00346	~~0.032~~ **0.0091**

Table H.19B
Model Results – HRA SCTG (individual unit)

Receptor	Cancer Risk Per Million	Chronic Hazard Index	Acute Hazard Index
Maximum Impact	0.086	0.00022	0.0017
MEIR	0.059	0.00015	0.0012
MEIW	0.003	0.00022	0.0017
Sensitive receptor	0.1	0.00012	0.00070

Table H.19C
Model Results – HRA AB

Receptor	Cancer Risk Per Million	Chronic Hazard Index	Acute Hazard Index
Maximum Impact	0.18	0.0005	0.0011
MEIR	0.026	0.00008	0.0003
MEIW	0.004	0.0005	0.001
Sensitive receptor	0.03	0.00008	0.0003

Appendix I

Greenhouse Gases

Out of the six GHG pollutants:

carbon dioxide, CO_2,
methane, CH_4,
nitrous oxide, N_2O
hydrofluorocarbons, HFCs
perfluorocarbons, PFCs
sulfur hexafluoride, SF_6

Only the first 3 are emitted by combustion sources. Sulfur hexafluoride can be emitted by circuit breakers.

The following emission factors and global warming potential (GWP) will be used in the calculations:

Table I.1 GHG Emission Factors

GHG	Emission Factor, natural gas		GWP
	kg/mmbtu	lbs/mmscf	
CO2	53.06	120,017	1.0
CH4	1.0E-03	2.26	25
N2O	1.0E-04	0.226	298

The emission factors in kg/mmbtu are converted to lbs/mmcf assuming the default HHV of 1026 btu/cf from 40 CFR98 Subpart C Table C-1. 1 kg = 2.2046 lbs.

CO2 equivalent (CO2e) is calculated using the following equation:

CO2e = CO2 + 25*CH4 + 298*N2O

Or, using fuel consumption (F):

CO2e = 120,017*F + 2.26*25*F + 0.226*298*F = 120,141*F (in lbs)

CO2e = 60.070*F (in tons)

Existing Sources

There are 2 existing sources of GHG emissions at the Huntington Beach site, Boilers 1 and 2. The following data will be used in the GHG PTE calculations for these units:

PTE

Maximum Rating

Boiler 1 2021 mmbtu/hr, 8,760 hrs/yr
Boiler 2 2021 mmbtu/hr, 8,760 hrs/yr

Table I.2 Boilers 1 and 2 GHG PTE

Pollutant	Boiler 1, tons		Boiler 2, tons	
	Hourly	Annual	Hourly	Annual
CO2	118.2	1,035,432	118.2	1,035,432
CH4	2.23E-03	19.5	2.23E-03	19.5
N2O	2.23E-04	1.95	2.23E-04	1.95
Total Mass	118.2	1,035,453	118.2	1,035,453
CO2e	118.3	1,036,503	118.3	1,036,503

Actual Emissions

The data from Appendix G is used to calculate the past actual emissions.

Table I.3 Boilers 1 and 2 GHG Actual Emissions

	2011	2012	2013	2014	2015
Boiler 1					
heat input, mmbtu	2,837,549	2,828,058	3,660,402	4,484,724	3,940,906
CO2, lbs	331,925,348	330,815,128	428,179,463	524,605,415	460,991,720
CH4, lbs	6255.7	6234.7	8069.7	9887.0	8688.1
N2O, lbs	625.6	623.5	807.0	988.7	868.8
Total Mass, tons	165,966	165,411	214,094	262,308	230,501
CO2e, tons	166,134	165,578	214,311	262,574	230,734
Boiler 2					
heat input, mmbtu	3,213,053	5,877,346	5,575,377	5,336,499	4,068,162
CO2, lbs	375,850,332	687,508,872	652,185,724	624,242,713	475,877,627
CH4, lbs	7083.5	12957.2	12291.5	11764.8	8968.7
N2O, lbs	708.3	1295.7	1229.1	1176.5	896.9
Total Mass, tons	187,929	343,762	326,100	312,128	237,944
CO2e, tons	188,119	344,109	326,430	312,444	238,185

New Sources

Combined Cycle Turbines

PTE –
The GHG potential to emit is based on heat input at baseload conditions (highest efficiency)

Table I.4 – Combined Cycle Turbines Heat Input

Hourly Heat Input	2,273 mmbtu/hr	Based on low temperature conditions
Annual Heat Input	14,926,720 mmbtu/yr	Based on 2,248 mmbtu/hr (site average temperature conditions) and 6640 hrs/yr operation (includes start ups and shutdowns)

Table I.5 Combined Cycle Turbines GHG PTE

GHG	Hourly Tons Per Turbine	Annual Tons Per Turbine	Annual Tons 2 Turbines
CO_2	132.9	873,034.6	1,746,069.1
CH_4	2.51E-03	16.45	32.9
N_2O	2.51E-04	1.65	3.29
Total Mass	132.9	873,052.7	1,746,105.3
CO_2e	133.1	873,937.6	1,747,872.5

Estimated Actual Emissions

The analysis of the projected actual GHG emissions over the course of the year considers all operating modes, including baseload, non-baseload, start ups, and shutdowns. This is essentially a calculation of the estimated efficiency of the turbine under actual operating conditions over the course of a year in order to determine the GHG emitted per MW. In order to make this determination, assumptions have to be made as to the number of hours in non-baseload operation, as well as the heat rates during starts and shutdowns.

Table I.6 Combined Cycle Heat Rate Data 1X1 Configuration

1X1 Configuration	Minimum CT Turndown (approx. 44%)	First Intermediate Point (approx. 63%)	Second Intermediate Point (approx. 81%)	Baseload (100%)
Net Plant Output (kW)	167,083	214,510	267,595	326,268
Gross Plant Output (kW)	177,553	277,169	280,534	339,854
Net Plant Heat Rate LHV (btu/kWh)	7,132	6,413	6,281	6,190
Gross Plant Heat Rate LHV (btu/kWh)	6,711	6,056	5,992	5,942
Net Plant Heat Rate HHV (btu/kWh)	7,913	7,116	6,970	6,868

Table I.7 Combined Cycle Heat Rate Data 2X1 Configuration

2X1 Configuration	Minimum CT Turndown (approx. 44%)	First Intermediate Point (approx. 63%)	Second Intermediate Point (approx.. 81%)	Baseload (100%)
Net Plant Output (kW)	347,857	444,518	547,347	661,631
Gross Plant Output (kW)	366,550	464,168	568,112	683,675
Net Plant Heat Rate LHV (btu/kWh)	6,851	6,190	6,142	6,105
Gross Plant Heat Rate LHV (btu/kWh)	6,502	5,928	5,917	5,908
Net Plant Heat Rate HHV (btu/kWh)	7,602	6,868	6,815	6,774

Table I.8 Combined Cycle Heat Rate Summary

Operating Mode		Hours/Yr	Net Heat Rate Btu/kWhr	Notes
Baseload	1X1	1200	7,217	Average net at HHV from Table I.6
Baseload	2X1	4900	7,015	Average net at HHV from Table I.7
Start ups	A. First fire to baseload	219	19,783	The annual start up time is based on 1) the permitted annual start ups and 2) the assumption that it takes 33

				minutes from first fire to baseload for a cold start and 25 minutes from first fire to baseload for a non-cold start. The heat rate is assumed to be 2.5 times the 44% load net heat rate at HHV for 1X1 configuation
	B. Baseload to completion	71	7,217	This is the time after the unit reaches baseload to completion of the start (27 minutes for cold start and 5 minutes for non-cold). For simplicity, the heat rate is assumed to be the same as 1X1 configuration.
Shutdowns	Baseload to zero fuel flow	250	11,870	The shutdown time is based on 500 annual shutdowns and 30 minutes from baseload to zero fuel flow. The heat rate is assumed to be 1.5 times the 44% load net heat rate at HHV for 1X1 configuration.

The overall weighted average heat rate is obtained by taking the average heat rate for each configuration multiplied by the hours of operation per configuration, and dividing by the total annual hours of operation. The GHG emissions are then calculated based on the average heat rate.

Overall net heat rate = [(Avg Heat Rate 1X1 Config * # of Hours for 1X1 Config) + (Avg Heat Rate 2X1 Config * # of Hours 2X1 Config) + (Start Heat Rate A * # of Hours Start Up A) + (Start Heat Rate B * # of Hours Start Up B) + (Shutdown Heat Rate * # of Hours Shutdowns)]/Total Annual Hours of Operation

Overall net heat rate = (7217 btu/kWh*1200 hrs + 7015 btu/h*4900 hrs +19783 btu/kWh*219 hrs + 7217 btu/kWh*71 hrs +11870 btu/kWh*250 hrs)/(6640) = 7657.6 btu/kWh

CO_2
7657.6 btu/kWh * 1000 kWh/MWh * 1*10E-06 MMBtu/Btu * 53.06 kg CO_2/MMBtu-HHV * 2.205 lb/kg = 895.9 lb CO_2/MWH

895.9 lb CO_2/netMWH @ HHV (no equipment degradation)

Assuming an 8% equipment degradation, the estimated heat rate and CO_2 emissions are

Heat Rate with equipment degradation 7657.6 btu/kw-hr*1.08 = 8270.2 btu/kw-hr
CO_2 with equipment degradation 895.9*1.08 = 967.6 lb CO_2/netMWH @ HHV

Simple Cycle Turbines

PTE –
The GHG potential to emit is based on heat input at baseload conditions (highest efficiency)

Table I.9 – Simple Cycle Turbines Heat Input

Hourly Heat Input	885 mmbtu/hr	Based on site average temperature conditions
Annual Heat Input	1,770,885 mmbtu/yr	Based on 885 mmbtu/hr (site average temperature conditions) and 2001 hrs/yr operation (includes start ups and shutdowns)

Table I.10 Simple Cycle Turbines GHG PTE

GHG	Hourly Tons Per Turbine	Annual Tons Per Turbine	Annual Tons 2 Turbines
CO2	51.8	103,575.5	207,151.1
CH4	9.75E-04	1.96	3.91
N2O	9.75E-05	0.20	0.40
Total Mass	51.8	103,577.7	207,155.4
CO2e	51.9	103,684.1	207,368.1

Estimated Actual Emissions

The analysis of the projected actual GHG emissions over the course of the year considers all operating modes, including baseload, non-baseload, start ups, and shutdowns. This is essentially a calculation of the estimated efficiency of the turbine under actual operating conditions over the course of a year in order to determine the GHG emitted per MW. In order to make this determination, assumptions have to be made as to the number of hours in non-baseload operation, as well as the heat rates during starts and shutdowns.

Table I.11 Simple Cycle Heat Rate Data

	50% Load	75% Load	Baseload (100%)
Net Turbine Output (kW)	47,476	72,448	99,355

Gross Turbine Output (kW)	48,935	73,908	100,814
Net Turbine Heat Rate LHV (btu/kWh)	10,394	8,801	8,027
Gross Turbine Heat Rate LHV (btu/kWh)	10,084	8,627	7,911
Net Turbine Heat Rate HHV (btu/kWh)	11,533	9,765	8,907

Table I.12 Simple Cycle Heat Rate Summary

Operating Mode		Hours/Yr	Net Heat Rate Btu/kWhr	Notes
Baseload		1750	10,068	Average net at HHV from Table I.11
Start ups	A. First fire to baseload	60	28,833	The annual start up time is based on 1) the permitted annual start ups and 2) the assumption that it takes 10.2 minutes from first fire to baseload. The heat rate is assumed to be 2.5 times the 50% load net heat rate at HHV.
	B. Baseload to completion	115	10,068	This is the time after the unit reaches baseload to completion of the start (19.8 minutes).
Shutdowns	Baseload to zero fuel flow	76	17,300	The shutdown time is based on 350 annual shutdowns and 13 minutes from baseload to zero fuel flow. The heat rate is assumed to be 1.5 times the 50% load net heat rate at HHV.

The overall weighted average heat rate is obtained by taking the average heat rate for each configuration multiplied by the hours of operation per configuration, and dividing by the total annual hours of operation. The GHG emissions are then calculated based on the average heat rate.

Overall net heat heat = [(Avg Heat Rate Baseload * # of Hours for Baseload) + (Start Heat Rate A * # of Hours Start Up A) + (Start Heat Rate B * # of Hours Start Up B) + (Shutdown Heat Rate * # of Hours Shutdowns)]/Total Annual Hours of Operation

Overall net heat rate = (10068 btu/kWh*1750 hrs + 28833 btu/h*60 hrs +10068 btu/kWh*115 hrs + 17300 btu/kWh*76 hrs)/(2001) = 10,905 btu/kWh

CO_2
10,905 btu/kWh * 1000 kWh/MWh * 1*10E-06 MMBtu/Btu * 53.06 kg CO_2/MMBtu-HHV * 2.205 lb/kg = 1275.9 lb CO_2/MWH

1275.9 lb CO2/netMWH @ HHV (no equipment degradation)

Assuming an 8% equipment degradation, the estimated heat rate and CO2 emissions are

Heat Rate with equipment degradation	10905 btu/kw-hr*1.08	=	11,777 btu/kw-hr
CO2 with equipment degradation	1275.9*1.08	=	1378.0 lb CO2/netMWH @ HHV

Auxiliary Boiler

The following data is used in the calculation:

Maximum Rating	=	71 mmbtu/hr
Maximum Hour/Day Operation	=	24
Maximum Heat Input/yr	=	189,155 mmbtu (includes start ups and shutdowns)

The following emission factors are from EPA (2009 FR *Mandatory Reporting of Greenhouse Gases, Final Rule*)

Pollutant	Factor
	kg/mmbtu
CO2	53.06
CH4	1.0E-03
N2O	1.0E-04

Table I.13 Auxiliary Boiler GHG Emissions

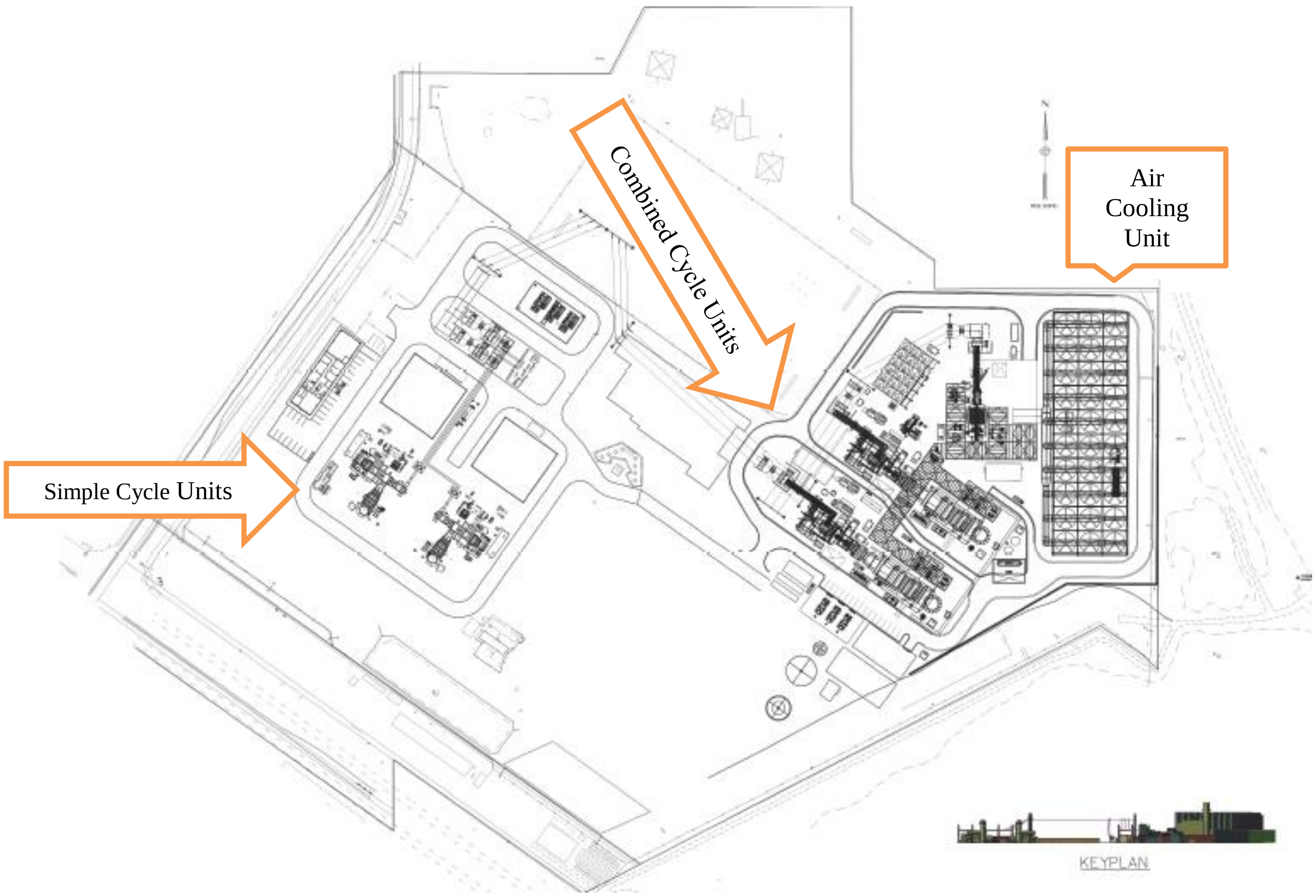
Pollutant	Emissions		
	lbs/hr	lbs/day	tons/yr
CO2	~~5067.0~~ **8,306.8**	~~121,609.03~~ **199,363.4**	11,065.31
CH4	~~9.58E-02~~ **0.16**	~~2.30~~ **3.76**	0.21
N2O	~~9.58E-03~~ **0.02**	~~0.23~~ **0.38**	0.02
Total Mass	~~5,066.83~~ **8,307.0**	~~121,611.11~~ **199,367.5**	11,065.56
CO2e	~~5,071.90~~ **8,315.4**	~~121,726.03~~ **199,569.6**	11,075.93

- SF6

There are 10 circuit brreakes at the AES HB facility. The leak rate is assumed to be 0.5 percent per year. The estimated SF6 mass emissions are 6.3 pounds per year. This is equivalent to 71.8 tons per year of CO2e assuming a global warming potential for SF6 of 22,800.

AEC Electric Breakers	Total SF6 (lbs)	Annual SF6 Emissions (lbs/yr)
1200A 230kV	230	1.15
1200A 230kV	230	1.15
1200A 230kV	230	1.15
3000A 230kV	230	1.15
10000A 18kV	25	0.125
10000A 18kV	25	0.125
10000A 18kV	25	0.125
2000A 230kV	216	1.08
GCB 13.8kV	24	0.12
GCB 13.8kV	24	0.12
	TOTAL	6.3

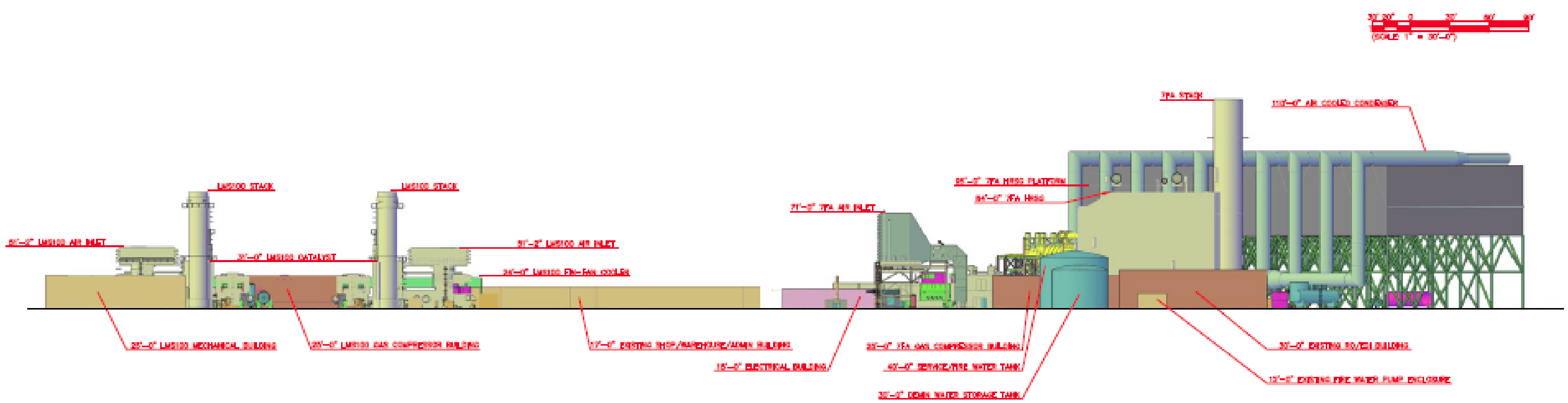
Appendix J – Facility Plot Plan



Appendix K – Elevation Views

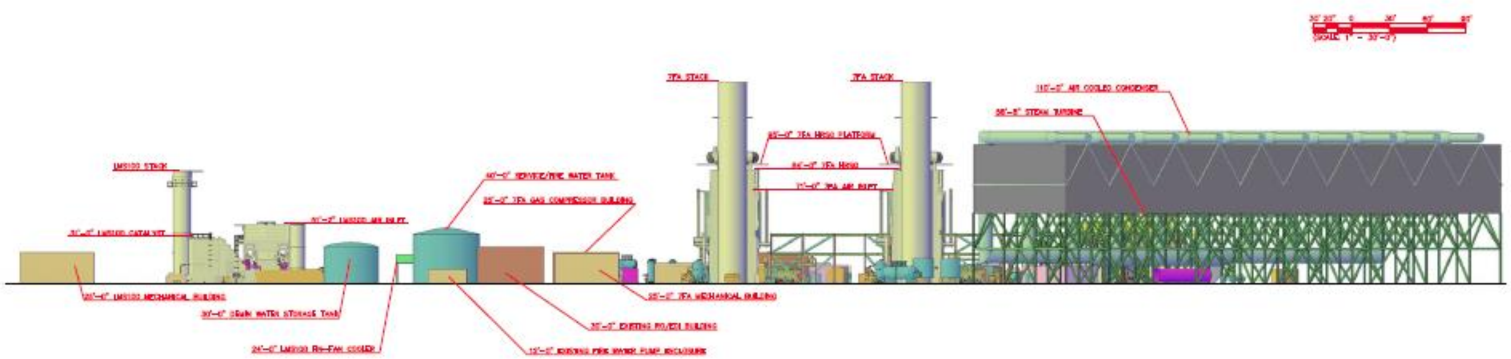
Looking East

Looking North



Looking South

Looking West



Appendix L – Process Flow

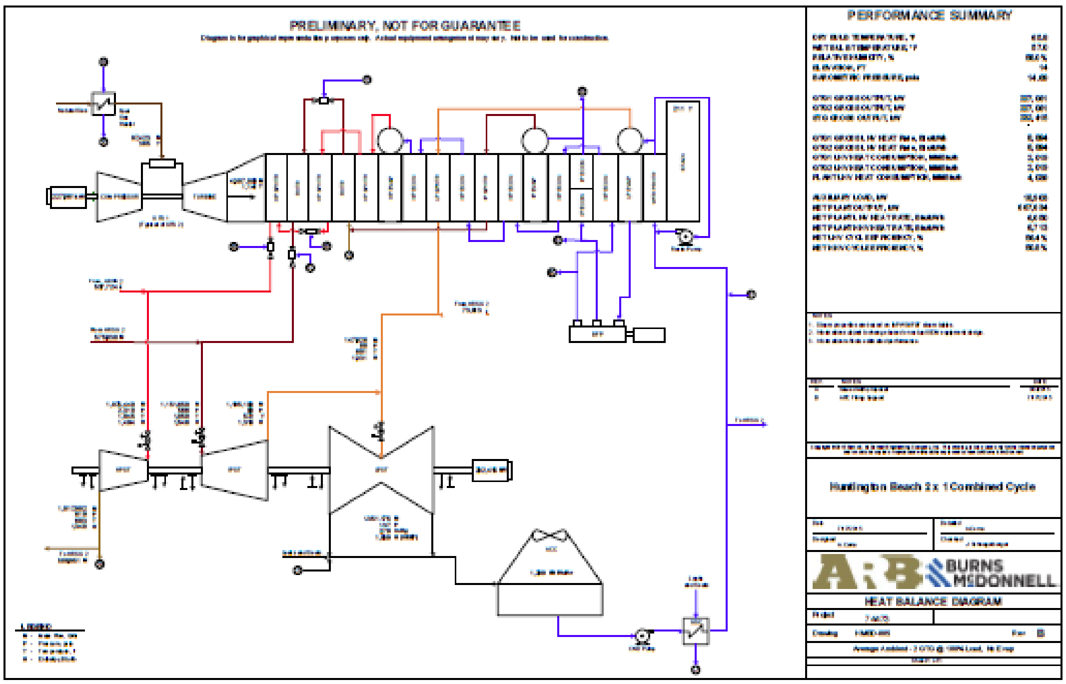


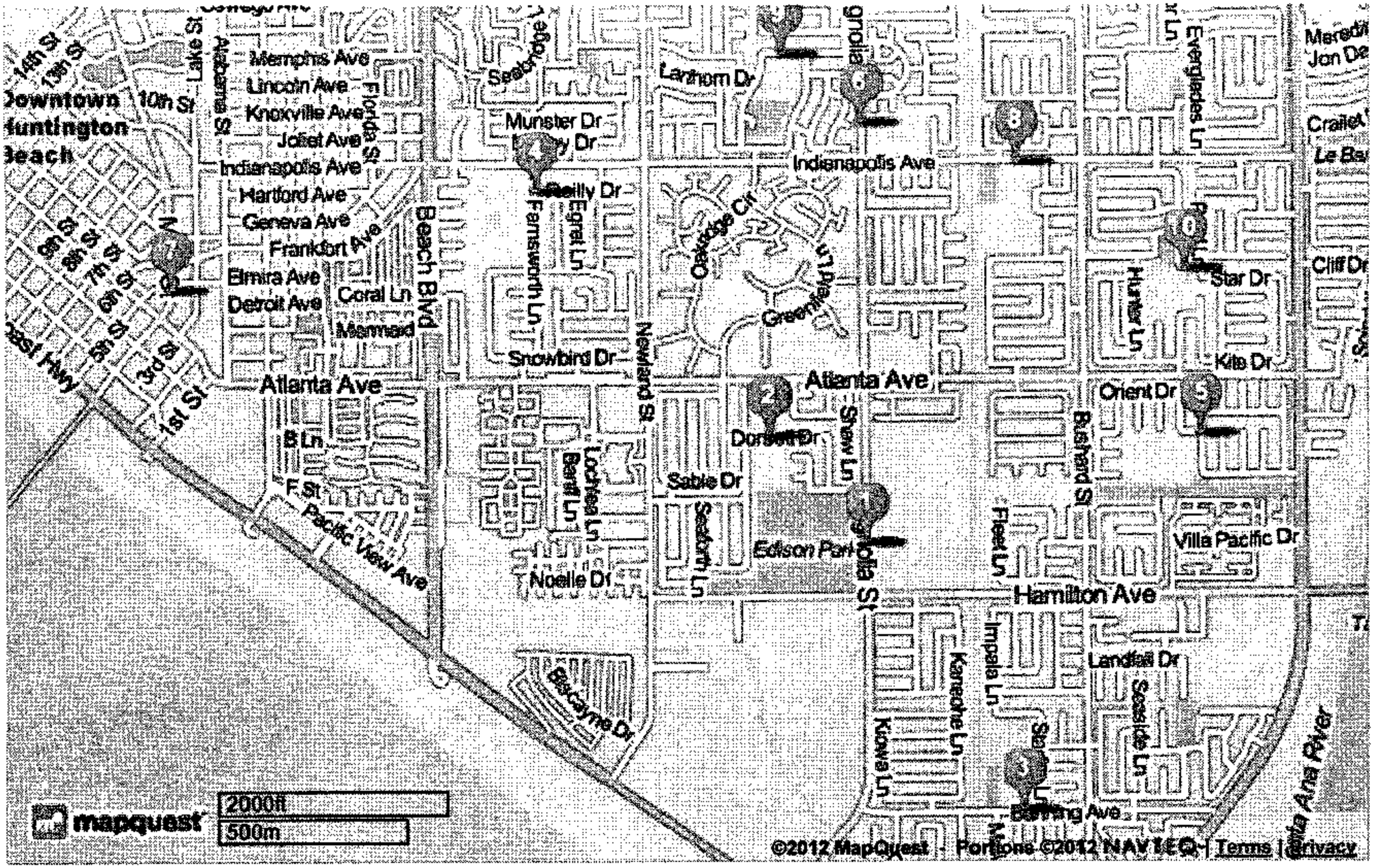
Figure 2.1-5a
Heat and Mass Balance 1 of 2
AES Amended Huntington Beach Energy Project
Huntington Beach, California

Appendix M

Nearest Schools

The following schools (K-12) were determined to be located within the vicinity of the proposed project:

	School	Location	Approx Distance from HBEP
1	Edison High	21400 Magnolia St	0.6 miles NE
2	William E Kettler School	8750 Dorsett Dr	0.65 miles NE
3	John H Eader School	9291 Banning Ave	0.91 miles SE
4	John R Peterson Elementary	20661 Farnsworth Lane	1.18 miles NW
5	Brethren Christian Jr/Sr High	21141 Strathmoor Lane	1.39 miles NE
6	St Simon and St Jude Elementary	20400 Magnolia St	1.14 miles NE
7	Sacred Heart Institute School	419 Main St	1.45 miles NW
8	Isaac L Sowers Middle School	9300 Indianapolis Ave	1.48 miles NE
9	S A Moffett Elementary	8900 Burlcrest Dr	1.5 miles N
10	Robert H Burke School	9700 Levee Dr	1.57 miles NE


Downtown Huntington Beach
Memphis Ave
Lincoln Ave
Knoxville Ave
Joliet Ave
Indianapolis Ave
Hartford Ave
Geneva Ave
Frankfort Ave
Elmira Ave
Detroit Ave
Coral Ln
Mermaid
Beach Blvd
Atlanta Ave
Munster Dr
Reilly Dr
Farnsworth Ln
Egret Ln
Snowbird Dr
Newland St
Lanthorn Dr
Oakridge Cir
Greenfield
Indianapolis Ave
Atlanta Ave
Dorsett Dr
Shaw Ln
Sable Dr
Seaforth Ln
Edison Park
Magnolia St
Hamilton Ave
Everglades Ln
Star Dr
Hunter Ln
Kite Dr
Orient Dr
Bushard St
Fleet Ln
Villa Pacific Dr
Impala Ln
Kaneohe Ln
Kiowa Ln
Landfall Dr
Seaside Ln
Banning Ave
Pacific View Ave
Biscayne Dr
Noelle Dr
Lochlea Ln
Banff Ln
B Ln
F St
Cliff Dr
Lake St
Alabama St
Florida St
14th St
13th St
10th St
9th St
8th St
7th St
6th St
5th St
3rd St
1st St
mapquest
2000ft
500m
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Appendix N

Facility Reported Emissions

The following tables summarize the annual emissions reported to SCAQMD by the facility for the most recent 2 year period available:

Table N.1 Reported Criteria Emissions

Pollutant	Emissions, tpy	
	2014	2015
NOx	31.737	30.288
CO	762.369	353.972
VOC	5.851	4.815
PM10	9.356	7.474
SOx	3.962	2.434

Table N.2 Reported Toxic Emissions

Pollutant	Emissions, lbs/yr	
	2014	2015
Ammonia	29681.74	10894.0
Benzene	16.305	13.389
Formaldehyde	35.052	29.013
Naphthalene	2.838	2.292
PAHs	0.96	0.784
1,3 Butadiene	0.185	0.294

These emissions are for the total facility and include operation of the utility boilers, the 2 emergency generators, and smaller unpermitted equipment used at the site.

Appendix O

Major Source Determinations

1. PSD

For purposes of PSD, the major source threshold for a fossil fuel fired steam electric plant with a heat input greater than 250 mmbtu/hr is the actual or potential to emit 100 tpy of any regulated NSR pollutant less any emission reduction from shutdown or modification. If the existing source exceeds 100 tpy on a pollutant specific basis, it is deemed to be an existing major source. In that case, if the modification to the existing major source is a major modification, the new source is subject to PSD. In the case of an existing minor source, if the new source 'in and of itself' is major, ie > 100 tpy, (without netting), PSD is applicable. For GHG emissions, the major source threshold is EITHER 75,000 tpy CO2e AND a net increase greater than 0 tpy total GHG mass if the source is subject to PSD for another regulated pollutant ('anyway' sources). Or, for an existing major source of GHG's, the modification is major if it results in an increase of 75,000 tpy CO2e AND a net increase of GHG mass greater than 0 tpy. For an existing minor source of GHG's, the modification is major if it results in an increase of 100,000 tpy CO2e AND a net increase greater than 100 tpy GHG.

Existing Facility

The PTE of the existing facility is summarized in Table O.1, and is calculated using the following data:

Boiler 1:

Rating	=	2021 mmbtu/hr
Fuel use	=	1.92 mmscf/hr (@ 1050 btu/scf)
Exhaust Flow	=	29 mmscf/hr (from 2001 source test)
NOx conc	=	7 ppm (use molar volume of 379 lb-lb-mole)
CO E.F.	=	0.274 lbs/mmbtu (from Table G.1)
VOC E.F.	=	1.64 lbs/mmcf (from Table G.1)
SO2 E.F.	=	0.83 lbs/mmcf (from Table G.1)
PM2.5 E.F.	=	1.86 lbs/mmcf (from Table G.1)
GHG E.F.	=	53.06 kg/mmbtu CO2, 1E-03 kg/mmbtu CH4, 1E-04 kg/mmbtu N2O

Boiler 2:

Rating	=	2021 mmbtu/hr
Fuel use	=	1.92 mmscf/hr (@ 1050 btu/scf)
Exhaust Flow	=	29 mmscf/hr (from 2001 source test)

NOx conc. = 7 ppm (use molar volume of 379 lb-lb-mole)
CO E.F. = 0.274 lbs/mmbtu (from Table G.1)
VOC E.F. = 0.9 lbs/mmcf (from Table G.1)
SO2 E.F. = 0.83 lbs/mmcf (from Table G.1)
PM2.5 E.F. = 2.1 lbs/mmcf (from Table G.1)
GHG E.F. = 53.06 kg/mmbtu CO2, 1E-03 kg/mmbtu CH4, 1E-04 kg/mmbtu N2O

Table O.1 Existing Facility Major Source Determination (PTE)

Pollutant	PTE, tpy		Total	Major Source?
	Boiler 1	Boiler 2		
NOx	107.8	107.8	215.6	Y
CO	2,415	2,415	4,830	Y
VOC	13.8	7.6	21.4	N
PM10/2.5	15.6	17.7	33.3	N
SO2	7.0	7.0	14.0	N
CO2e	1,029,792	1,029,792	2,059,584	Y

Table O.2 New Facility Major Source Determination (PTE)

Pollutant	PTE, tpy				Major Source?
	CCTG 1&2	SCTG 1&2	Aux Boiler	Total	
NOx	119.5	21.3	0.7	141.5	Y
CO	~~212.3~~ **196.7**	~~29.3~~ **22.5**	3.8	~~245.4~~ **223.0**	Y
VOC	64.8	6.1	0.5	71.4	N
PM10	56.44	12.5	0.7	69.6	N
PM2.5	56.44	12.5	0.7	69.6	N[1]
SOx	9.96	1.20	0.2	11.36	N
CO2e	1,747,873	207,368	11,076	1,966,317	Y

1 The major source threshold for PM2.5 under Rule 1325/40CFR 51 Appendix S is 70 tpy for areas of severe non-attainment

<u>Combined cycle Turbines</u>
NOx = 6,100 hrs *(16.8 lbs/hr) + 80 cold starts (61 lbs/start) + 88 warm starts (17 lbs/start) + 332 hot starts (17 lbs/start) + 500 shutdowns (10 lbs/shutdown)

PM2.5 = 6,100 hrs (8.5 lbs/hr) + 80 cold starts (8.5 lbs/start) + 88 warm starts (4.25 lbs/start) + 332 hot starts (4.25 lbs/start) + 500 shutdowns (4.25 lbs/shutdown)

<u>Simple Cycle Turbines</u>
NOx = 1,750 hrs *(8.2 lbs/hr) + 350 starts (16.6 lbs/start) + 350 shutdowns (3.12 lbs/shutdown)

PM2.5 = 1,750 hrs (6.24 lbs/hr) + 350 starts (3.12 lbs/start) + 350 shutdowns (1.35 lbs/shutdown)

For purposes of determining the net emissions increase for PSD and Rule 1325/40CFR 51 Appendix S, the actual emissions of the existing equipment to be shutdown (Boilers 1&2) is subtracted from the PTE of the new equipment (CCTG 1&2, SCTG 1&2, Auxiliary Boiler). This calculation needs to be applied to NOx, CO, and GHGs since the existing source is considered major for these 3 pollutants only.

Table O.3 New Facility Significant Increase Determination (PTE vs Past Actual)

	NOx, tpy	CO, tpy	CO2e
HBEP PTE	141.5	~~245.4~~ **223.0**	1,966,317
HB Boilers 1&2 Past Actual	42.6	1,221	521,524
Net Increase	98.9	0	1,444,793

Past actuals from Appendix G for years 2014 and 2015

2. 40CFR 64 CAM

The CAM Regulations of 40CFR 64 apply on a pollutant specific basis to units at major sources required to obtain a part 70 or 71 permit which have pre-control potential to emit (PTE) emission levels exceeding the major source thresholds.

Table O.4 Combined Cycle Turbine Emission Rates

	NOx	CO	VOC	PM10	SOx
Normal Operations Uncontrolled (lbs/hr)	75.4	51.0	5.8	8.5	1.5
Cold Start (total lbs)	61.0	325.0	36.0	8.5	1.5
Warm Start (total lbs)	17.0	137.0	25.0	4.25	0.75
Hot Start (total lbs)	17.0	137.0	25.0	4.25	0.75
Shutdown (total lbs)	10.0	133.0	32.0	4.25	0.75

Table O.5 Combined Cycle Turbine Annual Operating Schedule

Event	# Per Year	Duration/event	Duration/yr, hrs
Cold Start	80	1 hour	80
Warm Start	88	30 minutes	44
Hot Start	332	30 minutes	166
Shutdown	500	30 minutes	250
100% Load @ 65.8 deg F	//////////////	//////////////	6100
		Total Hrs	6640

Table O.6 Combined Cycle Turbine Pre Control Annual PTE and Major Source Determination

Pollutant	Annual Uncontrolled Emissions, 1 CCTG		Threshold	Major Source?
	Lbs/yr	Tpy	Tpy	
NOx	476,960	238.5	10	Y
CO	461,140	230.6	50	Y
VOC	64,760	32.4	10	Y
PM10	56,440	28.2	70	N
SOx	9,960	5.0	100	N

Table O.7 Simple Cycle Turbine Emission Rates

	NOx	CO	VOC	PM10	SOx
Normal Operations Uncontrolled (lbs/hr)	82.0	198.5	2.3	6.24	0.60
Start (total lbs)	16.6	15.4	2.8	3.12	0.30
Shutdown (total lbs)	3.12	28.9	3.06	1.35	0.13

Table O.8 Simple Cycle Turbine Annual Operating Schedule

Event	# Per Year	Duration/event	Duration/yr, hrs
Start	350	30 minutes	175
Shutdown	350	13 minutes	76
100% Load @ 65.8 deg F	//////////////	//////////////	1750
		Total Hrs	2001

Table O.9 Simple Cycle Turbine Pre Control Annual PTE and Major Source Determination

Pollutant	Annual Uncontrolled Emissions, 1 SCTG		Threshold	Major Source?
	Lbs/yr	Tpy	Tpy	
NOx	150,402	75.2	10	Y
CO	362,880	181.4	50	Y
VOC	6,076	3.0	10	N
PM10	12,484.5	6.2	70	N
SOx	12,000.5	0.60	100	N

Table O.10 Auxiliary Boiler Pre Control Annual PTE and Major Source Determination

Pollutant	Annual Uncontrolled Emissions, Aux Boiler		Threshold	Major Source?
	Lbs/yr	Tpy	Tpy	
NOx	2,188	1.1	10	N
CO	7,522	3.8	50	N
VOC	1,010	0.50	10	N
PM10	1,392	0.70	70	N
SOx	382	0.20	100	N

3. 40CFR 63 - NESHAPS

For NESHAPS, a major source is defined as a site that emits or has the potential to emit 10 tpy or more of any single HAP, or 25 tpy or more of any combination of HAPs (HAP being defined as one of the 187 air contaminants listed in the Section 112(b)(1), which does not include ammonia). See Appendix E for the calculations.

Table O.11 Total Facility TAC Emissions

Pollutant	CCTG 1&2	SCTG 1&2	Aux Boiler	Total	
	Lbs/yr	lbs/yr	lbs/yr	Lbs/yr	Tons/yr
1,3 Butadiene	12.60	1.5	//////////	14.1	7.05E-03
Acetaldehyde	5163.12	612.36	0.98	5776.46	2.89E+00
Acrolein	105.84	12.56	0.86	119.26	5.96E-02
Benzene	95.52	11.32	1.84	108.68	5.43E-02
Ethyl Benzene	935.1	110.9	2.19	1048.19	5.24E-01
Formaldehyde	10527.02	1248.54	3.90	11799.46	5.89E+00
Naphthalene	38.14	4.52	0.10	42.76	2.14E-02
PAH	26.34	3.12	0.03	29.49	1.47E-02
Propylene Oxide	849.04	100.7	///////////	949.74	4.75E-01
Toluene	3814.98	452.46	8.40	4275.84	2.14E+00
Xylene	1873.06	222.16	6.24	2101.46	1.05E+00
Hexane	//////////	//////////	1.46	1.46	7.30E-04
Propylene	//////////	//////////	168.01	168.01	8.40E-02
Total, lbs/yr	23342.7	2780.14	194.01		
Total 3 sources, tpy			13.2		

Appendix P

Reporting Emission Factor Determinations

NOx

The facility is required to report NOx emissions based on the emission factor in the permit for any operation which occurs before initial certification of the CEMS (missing data procedures are applicable after certification or 180 days after installation whichever occurs first). The facility will most likely certify its CEMS during or shortly after commissioning is completed. Therefore, the factor for the turbines will be based on the total expected emissions during commissioning as follows:

Table P.1 Combined Cycle Turbines RECLAIM Reporting Factor

Total Turbine Emissions During Commissioning, lbs	Total Turbine Fuel Use During Commissioning, mmcf	Reclaim Reporting Factor, lbs/mmcf
27,593	~~1445.6~~ **1656.3**	~~19.09~~ **16.66**

Refer to Table C.1

Table P.2 Simple Cycle Turbines RECLAIM Reporting Factor

Total Turbine Emissions During Commissioning, lbs	Total Turbine Fuel Use During Commissioning, mmcf	Reclaim Reporting Factor, lbs/mmcf
5,718	227.7	25.11

Refer to Table C.3

The facility is required to measure and record fuel use during commissioning.

The SOx factor for the turbines will be based on 0.25 gr/100 scf converted to lbs/mmscf as follows:

(0.25 grains/ 100 scf(lb/7000 rains)(64 lbs/lb-mole SO2/32 lbs/lb-mole S)(1E6 cf/mmcf) = 0.71 lbs SO2/mmcf fuel

Table P.3 Auxiliary Boiler RECLAIM Reporting Factors

Pollutant	Reporting Factor, lbs/mmcf	Source
NOx	49.180	Rule 2002 Table 1 for natural gas fired boilers subject to Rule1146
SOx	0.83	Rule 2002 Table 2 for natural gas fired external combustion equipment

VOC, PM10, CO
The monthly emission limits in Condition A63 will be verified with the use of reporting factors for VOC and PM10. CO will be verified with CEMS data, however, for the commissioning monthly limits, the CO will also be verified with an emission factor, since the CEMS will not be certified yet.

Table P.4 Combined Cycle Turbines Non-RECLAIM Reporting Factors During Commissioning

Pollutant	Total Turbine Emissions During Commissioning, lbs	Total Turbine Fuel Use During Commissioning, mmcf	Reporting Factor, lbs/mmcf
PM10	8,466	1656.3	5.11
VOC	14,681	1656.3	8.86
CO	101,326	1656.3	61.18

Table P.5 Combined Cycle Turbines Non-RECLAIM Reporting Factors After Commissioning

Pollutant	Baseload Emissions, lbs/hr	Baseload Maximum Fuel Use, mmcf	Reporting Factor, lbs/mmcf
PM10	8.5	2.16	3.94
VOC	5.75	2.16	2.66

Table P.6 Simple Cycle Turbines Non-RECLAIM Reporting Factors During Commissioning

Pollutant	Total Turbine Emissions During Commissioning, lbs	Total Turbine Fuel Use During Commissioning, mmcf	Reporting Factor, lbs/mmcf
PM10	1,747	227.7	7.67
VOC	836	227.7	3.67
CO	25,449	227.7	111.76

Table P.7 Simple Cycle Turbines Non-RECLAIM Reporting Factors After Commissioning

Pollutant	Baseload Emissions, lbs/hr	Baseload Maximum Fuel Use, mmcf	Reporting Factor, lbs/mmcf
PM10	6.24	0.84	7.43
VOC	2.3	0.84	2.74

Table P.8 Auxiliary Boiler Non-RECLAIM Reporting Factors

Pollutant	Emissions, lbs/hr	Maximum Fuel Use, mmcf	Reporting Factor, lbs/mmcf
PM10	0.51	0.0676	7.54
VOC	0.37	0.0676	5.47
CO	2.83	0.0676	41.9

Appendix Q

Existing Units Historical Power Generation

Table Q.1

		Gross MW		
Year	Month	HB1	HB2	RB7
2016	6	34384	35765	7034
	5	20536	8891	19342
	4	2504	0	0
	3	9375	360	0
	2	955	1890	0
	1	1042	28243	0
2015	12	21046	39937	0
	11	7344	31002	0
	10	35275	40979	0
	9	48060	49441	91800
	8	52492	56582	42413
	7	50104	46779	52871
	6	45828	33731	16443
	5	16857	11278	0
	4	7888	14627	0
	3	20526	27036	0
	2	0	0	0
	1	39234	0	0
2014	12	6606	35772	0
	11	6090	52372	30971
	10	32263	72695	0
	9	51396	71831	8820
	8	57013	66301	31
	7	59022	59723	0
Total		625,840	785,235	269,725
Unit 2 Yr Average		312,920	392,618	134,863
Unit Average Capacity Factor		0.17	0.21	0.03

HB 1 and 2 Rating = 215 MW, RB 7 Rating = 480 MW

Source: EPA Acid Rain Reporting

Appendix R

Summary of Applications and Processing Fees

The following table summarizes the application submittals and associated processing fees.

A/N	Submittal Date	Equip	Bcat	Fee Sch	Fee
578073	Sept 9, 2015	Combined Cycle Turbine #1	013709	G	$18,050.38
578074	Sept 9, 2015	Combined Cycle Turbine #2	013709	G Identical	9,025.19
578075	Sept 9, 2015	SCR/CO Catalyst #1	81	C	3,835.06
578076	Sept 9, 2015	SCR/CO Catalyst #2	81	C Identical	1,917.53
578077	Sept 9, 2015	Simple Cycle Turbine #1	013709	G	18,050.38
578078	Sept 9, 2015	Simple Cycle Turbine #2	013709	G Identical	9,025.19
578079	Sept 9, 2015	SCR/CO Catalyst #3	81	C	3,835.06
578080	Sept 9, 2015	SCR/CO Catalyst #4	81	C Identical	1,917,53
578081	Sept 9, 2015	Auxiliary Boiler	011705	E	6,085.38
578082	Sept 9, 2015	Auxiliary Boiler SCR	81	C	3,835.06
578083	Sept 9, 2015	Ammonia Storage	210900	A	1,521.32
578084	Sept 9, 2015	Ammonia Storage	210900	A Identical	760.66
578085	Sept 9, 2015	Oil/Water Separation	294804	C	3,835.06
578086	Sept 9, 2015	Oil/Water Separation	294804	C Identical	1,917.53
578087	Sept 9, 2015	Title V Revision	555009	C	1,994.55
				Expedited Review	41,805.67
				Total	$127,411.55

Schedule G equipment is also subject to a Time and Material Fee of $158.49/hr for hours worked over 117 hours.

Public notice, modeling review, and significant project fees will be billed to the facility after the permit is issued.

	Current Rate
Public Notice	$1,265.25
Modeling Review(1)	4,640.64
PSD Review	2,222.09
Total	$7,927.98

(1) Plus T&M @ $132.72/hr if above 35 hours

Appendix S

RECLAIM Trading Credit Requirement

- NOx

In accordance with Rule 2005 the facility is required to set aside sufficient RECLAIM Trading Credits (RTC) to cover the NOx emissions from the first year operation. The facility is not required to hold NOx RTCs for the subsequent years since the NOx PTE from the new equipment is less than the facility's initial allocation, and the facility is not considered 'new' (it has been in Reclaim since 1994).

Combined Cycle Turbines

During the 1st year, the combined cycle turbines will undergo commissioning, therefore, the NOx emissions for the 1st year of operation assumes both commissioning and normal operation for each turbine.

Equipment	1st Year Commissioning	Post Commissioning	Total 1st Year NOx Holding Requirement
CCTG 1	27,593	119,500	147,093
CCTG 2	27,593	119,500	147,093

Simple Cycle Turbines

During their 1st year of operation, the simple cycle turbines will undergo commissioning, therefore, the NOx emissions for the 1st year assumes both commissioning and normal operation for each simple cycle turbine.

Equipment	1st Year Commissioning	Post Commissioning	Total 1st Year NOx Holding Requirement
SCTG 1	5,718	21,252	26,970
SCTG 2	5,718	21,252	26,970

Auxiliary Boiler

The NOx holdings for the auxiliary boiler are based on the proposed annual operating schedule.

Equipment	Total 1st Year NOx Holding Requirement
Auxiliary Boiler	1,313

The total NOx RTC requirements are:

Equipment	Plant 1st Year of Operation	Interim Years After Plant 1st Year Prior to SCTG	SCTG Commissioning Year	After SCTG Commissioning and All Subsequent Years
CCTG 1	147,093	0	0	0
CCTG 2	147,093	0	0	0
SCTG 1	0	0	26,970	0
SCTG 2	0	0	26,970	0
Auxiliary Boiler	1,313	0	0	0
TOTAL	295,499	0	53,940	0

- The current NOx RTC holding for the Huntington Beach facility is 179,740 lbs/yr. The initial NOx RTC allocation for this facility is 1,276,547 lbs/yr.

- SOx

Rule 2005 paragraph (f)(1) requires that for a facility modification which increases the annual allocation to a level greater than the starting allocation, offsets are required for the first year of operation, and each subsequent year. Since the facility opted into SOx RECLAIM, there was no initial allocation for SOx. Therefore, any increase is considered subject to the holding requirement for all compliance years.

Combined Cycle Turbines

During the 1st year, the combined cycle turbines will undergo commissioning, therefore, the SOx emissions for the 1st year of operation assumes both commissioning and normal operation for each turbine. After the first year, commissioning will be completed, and the anticipated annual SOx emissions are based on the proposed operating schedule.

Equipment	1st Year Commissioning	1st Year Post Commissioning	Total 1st Year SOx Holding Requirement	After 1st Year SOx Holding Requirement
CCTG 1	4,843	9,960	14,803	9,960
CCTG 2	4,843	9,960	14,803	9,960

Simple Cycle Turbines

During their 1st year of operation, the simple cycle turbines will undergo commissioning, therefore, the SOx emissions for the 1st year assumes both commissioning and normal operation for each simple cycle turbine. After the first year, commissioning will be completed, and the anticipated annual SOx emissions are based on the proposed operating schedule.

Equipment	1st Year Commissioning	1st Year Post Commissioning	Total 1st Year SOx Holding Requirement	After 1st Year SOx Holding Requirement
SCTG 1	459	1200.5	1,660	1,201
SCTG 2	459	1200.5	1,660	1,201

Auxiliary Boiler

The SOx holdings for the auxiliary boiler are based on the proposed annual operating schedule.

Equipment	Total 1st Year NOx Holding Requirement	After 1st Year NOx Holding Requirement
Auxiliary Boiler	382	382

The total SOx RTC requirements are:

Equipment	Plant 1st Year of Operation	Interim Years After Plant 1st Year Prior to SCTG	SCTG Commissioning Year	After SCTG Commissioning and All Subsequent Years
CCTG 1	14,803	9,960	9,960	9,960
CCTG 2	14,803	9,960	9,960	9,960
SCTG 1	0	0	1,660	1,201
SCTG 2	0	0	1,660	1,201
Auxiliary Boiler	382	382	382	382
TOTAL	29,988	20,302	23,622	22,704

- The current SOx RTC holding for the Huntington Beach facility is 7,597 lbs/yr. The initial SOx RTC allocation for this facility is 0 lbs/yr.

Appendix T

Review of Criteria Pollutant BACT Levels for Recent Projects

Following is a partial list of the BACT levels for some recent projects that were considered in the criteria pollutant BACT analysis for HBEP from the SCAQMD, EPA, BAAQMD, CARB, and SJVAPCD BACT clearinghouses.

NOx

Combined Cycle Turbines

Facility	NOx Emissions Limit @ 15% O2
Oakley Generating Station	2.0 ppm (1 hour)
GWF Tracy Combined-Cycle Project	2.0 ppm (1 hour)
Watson Cogeneration Project	2.0 ppm (1 hour)
Magnolia Power Project	2.0 ppm (3 hour)
Otay Mesa Energy Center	2.0 ppm (1 hour)
El Segundo Power	2.0 ppm (1 hour)
LADWP Scattergood	2.0 ppm (1 hour)

Simple Cycle Turbines

Facility	NOx Emissions Limit @ 15% O2
Lambie Energy Center	2.5 ppm (3 hour)
EL Cajon Energy, LLC	2.5 ppm (1 hour)
Escondido Energy Center	2.5 ppm (1 hour)
Pio Pico Energy Center	2.5 ppm (1 hour)
LADWP Scattergood	2.5 ppm (1 hour)
LADWP Haynes	2.5 ppm (1 hour)
EL Segundo Power	2.5 ppm (1 hour)

Auxiliary Boiler

Facility	NOx Emissions Limit @ 3% O2
Moundsville Power LLC	2.0 lbs/hr
Pinecrest Energy Center LLC	16 ppmvd
La Paloma Energy Center LLC	0.02 lbs/mmbtu
City of Palmdale Hybrid	9 ppmvd (3 hour)
Consumers Energy	0.018 lb/mmbtu

Sandy Creek Energy Assoc	1.8 lbs/hr
AES HB	5 ppm (1 hour)

CO

Combined Cycle Turbines

Facility	CO Emissions Limit @ 15% O2
Oakley Generating Station	2.0 ppm (1 hour)
Vernon City Light and Power	2.0 ppm (3 hour)
Russell City Energy Center	2.0 ppm (1 hour)
LADWP Scattergood	2.0 ppm (1 hour)
El Segundo Power	2.0 ppm (1 hour)
CPV Warren	1.3 ppm without duct firing, 1.2 ppm with duct firing
Warren County Power	1.3 ppm without duct burners
Kleen Energy Systems	0.9 ppm (1 hour)

The Warren County Power Station became operational in December 2014. ***The CO limit in the permit is 1.5 ppm without duct firing and 2.4 ppm with duct firing.*** *The Kleen Energy Systems permit allows exemptions from the 0.9 ppm CO limit during load changes.*

Simple Cycle Turbines

Facility	CO Emissions Limit @ 15% O2
Great River Energy	4.0 ppm (4 hour)
Carlsbad Energy	4.0 ppm (1hour)
Pio Pico Energy Center	4.0 ppm (1 hour)
Canyon Power	4.0 ppm (1 hour)
LADWP Scattergood	4.0 ppm (1 hour)
LADWP Haynes	4.0 ppm (1 hour)
EL Segundo Power	4.0 ppm (1 hour)
Mariposa Energy	**2.0 ppm (3hour)**
Moss Landing	**2.0 ppm (1hour)**

Auxiliary Boiler

Facility	CO Emissions Limit @ 3% O2
Moundsville Power LLC	4.0 lbs/hr
Pinecrest Energy Center LLC	75 ppmvd

La Paloma Energy Center LLC	75 ppmvd (3 hour)
City of Palmdale Hybrid	50 ppmvd (3 hour)
Consumers Energy	0.035 lb/mmbtu
Southern Co/Georgia Power	0.037 ln/mmbtu (3 hour)
Sandy Creek Energy Assoc	6.1 lbs/hr
Northern States Power, Xcel	0.08 lb/mmbtu (3 hour)
AES HB	5 ppm (1 hour)

The AES HB units 3 and 4 were large utility boilers, rated at 2,088 mmbtu/hr using CO oxidation catalysts (these are now retired units). There is no indication in the BACT Clearinghouses that smaller auxiliary-type boilers have been required to achieve this emission level.

VOC

Combined Cycle Turbines

Facility	VOC Emissions Limit @ 15% O2
Florida Power and Light Martin	1.3 ppm without duct firing
Duke Energy	1 ppm without duct firing (3 hour)
Fairbault Energy Park	1.5 ppm without duct firing
VA Power – Possum Point	1.2 ppm without duct firing
Sacramento Municipal	1.4 ppm
Liberty Generating Station	1.0 ppm
Empire Power, NY	1.0 ppm
CPV Warren	0.7 ppm without duct firing, 1.6 ppm with duct firing
Warren County Power	0.7 ppm without duct firing, 1.0 ppm with duct firing
Chouteau Power	0.3 ppm with duct firing (3 hour)

Different test methods are used by different air districts to stack test for VOC emissions, which results is varying test results. The BACT limit of 2.0 ppm chosen for HBEP is based on the method used in SCAQMD.

Simple Cycle Turbine

Facility	VOC Emissions Limit @ 15% O2
Indigo Energy	2.0 ppm
LADWP Scattergood	2.0 ppm (1 hour)
El Segundo Power	2.0 ppm (1 hour)
El Paso Belle Glade, FL	1.4 ppm
Deerfield Beach Energy Center	1.4 ppm
Florida Power and Light Manatee	1.3 ppm
Progress Bartow Power	1.2 ppm

Different test methods are used by different air districts to stack test for VOC emissions, which results is varying test results. The BACT limit of 2.0 ppm chosen for HBEP is based on the method used in SCAQMD.

Andrew Bhaskar, Chris

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

MEMORANDUM

DATE: May 18, 2016

TO: Andrew Lee

FROM: Ian MacMillan IM

SUBJECT: Modeling Review of Huntington Beach Energy (Facility ID #115389) (A/N: 578073-86)

As you requested, Planning, Rule Development & Area Sources (PRDAS) staff reviewed the dispersion modeling analysis and health risk assessment (HRA) conducted for the proposed construction of four gas turbines and an auxiliary boiler at the AES Huntington Beach Generating Station located at 21730 Newland Street in the city of Huntington Beach. The project consists of one two-on-one combined-cycle power block (GE 7FA.05), one simple-cycle power block (two GE LMS 100PB), along with one natural-gas fired auxiliary boiler. The dispersion modeling analysis and HRA (report) and electronic files were submitted for PRDAS staff review along with the modeling request memo dated December 18, 2015, with a revised dispersion modeling analysis and HRA (report) submitted with the modeling request memo dated March 18, 2016.

SUMMARY OF MODELING REVIEW

- **Modeling Conducted Pursuant to SCAQMD Regulations XIII Requirements**
  - ✓ SCAQMD Rule 1304(a)(2) provides an exemption from the modeling requirement of Rule 1303(b)(1) for the installation of the new turbines since AES is permanently retiring their existing electric steam utility boilers. The modeling requirements of Rule 1303(b)(1) do apply to the proposed auxiliary boiler. The modeled impacts from the auxiliary boiler are below all thresholds in Rule 1303.
- **Modeling Conducted Pursuant to SCAQMD Regulation XIV Requirements**
  - ✓ The project's health risks are less than the Rule 1401 cancer and non-cancer permit limits of 10 in one million (for permit units with T-BACT), and hazard index of 1, respectively.
- **Modeling Conducted Pursuant to SCAQMD Regulation XX Requirements**
  - ✓ All equipment in the proposed project is subject to SCAQMD Rule 2005 review for NO_2 and SO_2. Modeled impacts from each piece of equipment are below all ambient air quality thresholds for NO_2 and SO_2.
- **Modeling Conducted Pursuant to Federal Prevention of Significant Deterioration (PSD) Requirements**
  - ✓ The project is subject to PSD regulations for CO, NO_2, PM_{10}, and greenhouse gases (GHG). Impacts were compared to applicable Class I and II SIL's. The project's CO impacts do not exceed the Significant Impact Level (SIL) and no further PSD analysis is needed. The project's PM10 impacts will not exceed the SIL only after a permit condition is added to limit the operating parameters of the project, as agreed to by the applicant. Since the project's NO_2 impacts exceeded the 1-hour NO_2 SIL, a cumulative impact assessment was conducted. As there were no modeled exceedances of the federal 1-hour NO_2 standard, no further PSD analysis is required.

- ✓ The project's impacts on visibility and deposition at the nearest Class I area did not exceed the screening threshold. Additional information is provided in the detailed comments below on an additional analysis requested by EPA Region 9 on visibility in Class II areas.

- **Modeling Conducted Pursuant to CEQA**
  - ✓ The modeling report was prepared by the project applicant as part of an Addendum to a previously approved Final Staff Assessment (FSA) for the California Energy Commission (CEC). An FSA is the CEC's CEQA document prepared under its certified regulatory program. PRDAS staff has confirmed the modeling analysis conclusion that the proposed project's impacts do not exceed what was previously approved in the FSA.
  - ✓ SCAQMD is both a responsible agency and a commenting agency under CEQA for this project. As noted above in the memo summary, the modeling analysis conforms to SCAQMD regulations and SCAQMD does not have any comments as a responsible agency.
  - ✓ In order to evaluate the project's air quality impacts for the California Energy Commission's (CEC's) CEQA document, the applicant included a modeling analysis of the impacts from the entire project. The modeling analysis that PRDAS staff reviewed concluded that the project would exceed SCAQMD PM10 and PM2.5 localized thresholds that are recommended for general CEQA use, but that impacts would be less than significant because the project would provide emission offsets. The impacted area is in an unoccupied area adjacent to the project site.
  - ✓ As a commenting agency, PRDAS staff notes that regional emission offsets should not be used as mitigation for a localized impact. However, as the turbine portion of this project is exempt from analyzing PM10 localized impacts pursuant to SCAQMD Regulation XIII, the SCAQMD PM10 localized CEQA thresholds for general use should only be applied to the boiler portion of the project. The boiler on its own does not exceed SCAQMD PM10 and PM2.5 localized CEQA thresholds.

DETAILED COMMENTS ON THE MODELING REVIEW

AERMOD Dispersion Modeling Approach

- ✓ The applicant utilized AERMOD (version 15181) for the air dispersion modeling, which is the current EPA approved model.
- ✓ The applicant processed meteorological data from the John Wayne/Orange County Airport's NWS station (WBAN Station #93184), which is appropriate for the project. This station was approved for use in PRDAS's staff memo dated December 12, 2013. Meteorological data was collected for the years 2010 – 2014, and was processed with AERMET (version 15181). Upper air data was collected from the San Diego Miramar NWS station (WBAN Station #03190). AERMINUTE (version 15272) was used to process 1-minute rolling averaged ASOS wind data. A 0.50 m/s threshold wind speed was applied in Stage 3 AERMET processing. Surface station data was processed with the coordinates set to 33.68°, -117.87°.
- ✓ The AERMOD modeling generally conforms to the SCAQMD's dispersion modeling methodology.
- ✓ The applicant used the monitoring data for SRA 18, North Coastal Orange County (Costa Mesa) for the pollutants CO, NO_2, O_3, and SO_2 and SRA 19, Saddleback Valley (Mission Viejo) monitoring stations for PM_{10} and $PM_{2.5}$. Three years of data was used (2011-2013) to determine the background concentrations. As 2014 monitoring data is now available, background concentrations were updated for the applicable pollutants. The predicted modeling impacts were added to the highest background concentrations for comparison to the state and federal ambient air quality standards (AAQS).
- ✓ The receptor grid area covered is adequate to determine the maximum impacts from the facility.
- ✓ Since there are no restrictions for the auxiliary boiler on the operating hours, the modeling assumed continuous operations of 8760 hours/year (24 hours/day, 7 days/week, and 52 weeks/year). For the combined cycle turbines, the permit was evaluated at 6100 operating hours per year and 1750 hours per year for the simple cycle turbines.
- ✓ PRDAS staff reproduced the modeling analysis and our results and review are summarized below.

Modeling Review for Compliance with Applicable Federal, State, and Local Regulations

1. Federal PSD Air Quality Analyses

- ✓ The proposed project is subject to Prevention of Significant Deterioration (PSD) review for CO, NO_2, and PM_{10}; therefore, the project's impacts are compared to the corresponding U.S. EPA significant impacts levels (SIL) for each pollutant[1].

a. Class I Areas

- ✓ The nearest Class I areas to the project site are the San Gabriel Wilderness and Cucamonga Wilderness areas located approximately 69 km away. A radial receptor ring was placed at

[1] Commissioning activities are not to be included per discussion with U.S. EPA Region 9 staff.

a distance of 50 km from the project (50 km is the maximum receptor distance of the AERMOD model).

✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1A, 1B, 2, 3A, 3B, 3C, and 3D of the report and are assumed to be correct.

Table A – Total Project Operational Impacts to Class I Areas

Pollutant & Averaging Time	Project's Modeled Operational Impact (μg/m³)	Class I SIL (μg/m³)	Exceeds Class I SIL?
NO_2, Annual	0.006	0.1	No
PM_{10}, 24-hr	0.042	0.2	No
PM_{10}, Annual	0.006	0.32	No

b. Class II Areas

✓ The project applicant identified five Class II areas in the project vicinity – Crystal Cove State Park, Water Canyon State Park, Chino Hills State Park, San Mateo Canyon Wilderness Area, and Huntington Beach State Park.

✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1A, 1B, 2, 3A, 3B, 3C, and 3D of the report and are assumed to be correct.

Table B – Total Project Operational Impacts to Class II Areas

Pollutant & Averaging Time	Project's Modeled Operational Impact (μg/m³)	Class II SIL (μg/m³)	Exceeds Class II SIL?
CO, 1-hr	631	2,000	No
CO, 8-hr	149	500	No
NO_2, 1-hr [b]	94.5	7.5 [a]	**Yes**
NO_2, Annual [b]	0.6	1	No
PM_{10}, 24-hr	4.7	5	No
PM_{10}, Annual	0.6	1	No

Note: [a] Interim/Proposed SIL, not yet finalized.
[b] The conversion of NO_X to NO_2 was done using Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

✓ For 24-hour PM_{10}, refined modeling was performed assuming one GE 7FA.05 would operate 24 hours per day at 44 percent load, and one GE 7FA.05 would operate 20 hours per day at 44 percent load and 4 hours per day at 75 percent load. This will require a permit condition.

✓ The U.S. EPA established a new 1-hour NO_2 standard of 0.100 ppm (or 188 μg/m³) that became effective on April 12, 2010. In order to show compliance with the federal 1-hour

NO_2 standard, the applicant used the maximum hourly emissions from startup, shutdown, and normal operations. Given the number of startups and shutdowns, the emissions from these events cannot be considered as intermittent, as described in the U.S. EPA's memo dated March 1, 2011. Emissions from commissioning were not included because commissioning is a once in a lifetime event and the form of the standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations.

✓ The maximum 1-hour NO_2 impact from the proposed project is 94.5 $\mu g/m^3$. This impact exceeds the U.S. EPA 1-hour NO_2 significance impact level of 7.52 $\mu g/m^3$. Therefore, a cumulative impact assessment is necessary.

✓ For the cumulative impact assessment, three facilities (Orange County Sanitation District's Huntington Beach and Fountain Valley facilities and Beta Offshore) as well as emissions from shipping lane activity off the coast were selected to be included based on their facility emissions and distance to the project. Seasonal, by hour-of-day background concentrations from the Costa Mesa monitoring station were used in the modeling. The conversion of NO_x to NO_2 was done using the Tier 2 ARM, with a value of 0.8 for the 1-hour. Following the form of the standard, the 1-hour NO_2 impact from the project plus cumulative projects plus background is 144.0 $\mu g/m^3$, which is less than the federal 1-hour NO_2 standard of 188 $\mu g/m^3$; therefore, the project does not exceed PSD requirements.

c. <u>Visibility Impact Analysis for Class I and Class II Areas</u>

✓ In order to estimate the potential impacts on visibility and deposition at the nearest Class I areas, a screening criteria was used for projects located more than 50 km away from a Class I area. The emissions/distance (Q/D) is calculated using the project's total annual emissions of SO_2, NO_X, PM_{10}, and H_2SO_4 (based on 24-hour maximum allowable emissions) divided by the distance between the project and the nearest Class I area. The project's total annual emissions are 420 TPY. The Q/D ratio is 6.1, which is less than the threshold of 10; therefore, modeling of visibility and deposition impacts to Class I areas are not necessary.

✓ Additionally, the project's impacts on visibility in Class II areas were also analyzed pursuant to EPA Region 9 request. The evaluation below is presented solely for informational purposes as there are no thresholds for visibility impacts on Class II areas. The project utilized the criteria and thresholds for Class I areas, which is conservative. Visibility impacts are based on the calculation of two factors – plume contrast and color contrast (ΔE) of the plume when compared to the sky and terrain backgrounds. For Class I areas, the criteria used is based on a perceptibility threshold of 0.05 (absolute value) for contrast and 2.0 for ΔE.

✓ The project applicant identified five Class II areas in the project vicinity – Crystal Cove State Park, Water Canyon State Park, Chino Hills State Park, San Mateo Canyon Wilderness Area, and Huntington Beach State Park. Using the Level 1 VISCREEN analysis, three areas were screened out and did not require further analysis. The two areas requiring a Level 2 VISCREEN analysis include Crystal Cove State Park and Huntington Beach State Park.

✓ Using the 5-year meteorological data from the John Wayne airport, joint frequency distribution tables were created and used to determine the worst-case single wind speed and stability class required for a Level 2 VISCREEN analysis. Using the Level 2

VISCREEN analysis, the project's impacts for both contrast and ΔE are less than the Class I thresholds for Crystal Cove State Park.

- ✓ Huntington Beach State Park was analyzed using a Level 2 VISCREEN analysis for each individual stability class. Based on the modeled impacts, the sky background Class I thresholds are exceeded for contrast and color difference for stability classes A, B, C, and D. This corresponds to 4.5% of the time or 395 hours per year when the wind is blowing towards the State Park and the park is open (from 6:00am to 10:00pm).
- ✓ Currently, there are no established thresholds for Class II areas; therefore, it is not possible to determine if the project presents a significant visibility impact to Class II areas.

2. Rule 2005 Air Quality Analyses

- ✓ The proposed project is subject to SCAQMD Rule 2005 review for NO_2 and SO_2. Each combustion emission unit was modeled separately, and the maximum results are presented below.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1A, 1B, 2, 3A, 3B, 3C, and 3D of the report and are assumed to be correct.
- ✓ NO_2 and SO_2 modeled concentrations per emission unit, when added to the highest background values, are below applicable ambient air quality standards.

Table C – Impacts for Rule 2005
Maximum Results From Highest Permit Unit For Each Pollutant

Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu g/m^3$)	Background Concentration [a] ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	California AAQS [b] ($\mu g/m^3$)	Federal AAQS [b] ($\mu g/m^3$)	Exceeds Threshold ?
NO_2, 1-hour [c]	60.3	142	202.3	339	-	No
NO_2, 1-hour [c]	62.0	98.2	160.2	-	188 [d]	No
NO_2, Annual [c]	0.3	21.8	22.1	57	100	No
SO_2, 1-hr	5.7	23.1	28.8	655	-	No
SO_2, 1-hr	2.8	8.8	11.6	-	196 [e]	No
SO_2, 3-hr	5.1	23.1	28.2	-	1,300	No
SO_2, 24-hr	1.7	5.2	6.9	105	-	No

Note: [a] Maximum values for CO, NO_2, and SO_2 from SRA 18, North Coastal Orange County (No. 3195) monitoring station and PM_{10} from SRA 19, Saddleback Valley (No. 3812) monitoring station for the last three years (2012-2014).
[b] Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted
[c] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.
[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 $\mu g/m^3$). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.
[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 $\mu g/m^3$). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

3. SCAQMD Regulation XIII - Impacts During Normal Operations

- ✓ The auxiliary boiler is subject to the modeling requirements of Regulation XIII and the Rule 1303 thresholds apply.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1A, 1B, 2, 3A, 3B, 3C, 3D, 11A, and 11B of the report and are assumed to be correct.

Table D – Impacts during Normal Operation – Auxiliary Boiler

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (µg/m³)	Background Concentration [a] (µg/m³)	Total Concentration (µg/m³)	California AAQS [b] (µg/m³)	Federal AAQS [b] (µg/m³)	Exceeds Threshold ?
CO, 1-hr	23	3,435	3,458	23,000	40,000	No
CO, 8-hr	11	2,519	2,530	10,000	10,000	No
NO_2, 1-hr [c]	2.7	142.3	145.0	339	-	No
NO_2, 1-hr [c]	2.1	98.7	100.8	-	188 [d]	No
NO_2, Annual [c]	0.2	21.8	22.0	57	100	No
SO_2, 1-hr	0.4	23.1	23.5	655	-	No
SO_2, 1-hr	0.4	8.8	9.2	-	196 [e]	No
SO_2, 3-hr	0.3	23.1	23.4	-	1,300	No
SO_2, 24-hr	0.2	5.2	5.4	105	-	No
PM_{10}, 24-hr	0.5	51.1	51.6	-	150	No
Non-attainment Pollutant & Averaging Time	**Maximum Modeled Concentration (µg/m³)**	**California AAQS (µg/m³)**	**Federal AAQS (µg/m³)**	**Rule 1303 Thresholds [f] (µg/m³)**		**Exceeds Threshold ?**
PM_{10}, 24-hr	0.5	50	150	2.5		No
PM_{10}, Annual	0.2	20	-	1		No
$PM_{2.5}$, 24-hr	0.5	-	35	2.5		No
$PM_{2.5}$, Annual	0.2	12	12	1		No

Note: [a] Maximum values for CO, NO_2, and SO_2 from SRA 18, North Coastal Orange County (No. 3195) monitoring station and PM_{10} from SRA 19, Saddleback Valley (No. 3812) monitoring station for the last three years (2012-2014).
[b] Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted
[c] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.
[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 µg/m³). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.

[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 µg/m^3). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.
[f] The South Coast Air Basin is designated non-attainment for the state PM_{10} standards, and state and federal $PM_{2.5}$ standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

4. SCAQMD Regulation XIV - Health Risk Impacts

- ✓ The applicant performed the risk assessment with the Hot Spots Analysis and Reporting Program Version 2 (HARP2, version 15197).
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 16, 17, and 18 of the report and are assumed to be correct.
- ✓ The peak cancer risk for the proposed project is 4.7 in one million for a resident and 0.2 in one million for a worker. Based on a radius of 2.03 km (for the one in a million cancer risk contour) and a population density of 7,000 persons/km^2, the cancer burden is estimated to be 0.42. This is below the cancer burden threshold of 0.5.

Table E – Health Risk Impacts - Total Project

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Sensitive	4.7 in one million	6.73 E-03	1.72 E-02	10 in one million [a]	1.0	1.0	No
Worker	0.2 in one million	1.01 E-02	4.06 E-02	10 in one million [a]	1.0	1.0	No

Note: [a] For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million

Table F – Health Risk Impacts – By Permit Unit - GE 7FA.05

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Sensitive	2.4 in one million	3.46 E-03	9.05 E-03	10 in one million [a]	1.0	1.0	No
Worker	0.1 in one million	6.04 E-03	3.16 E-02	10 in one million [a]	1.0	1.0	No

Note: [a] For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million

Table G – Health Risk Impacts – By Permit Unit - GE LMS 100PB

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Sensitive	0.1 in one million	1.06 E-04	7.76 E-04	10 in one million [a]	1.0	1.0	No
Worker	0.003 in one million	1.82 E-04	1.69 E-04	10 in one million [a]	1.0	1.0	No

Note: [a] For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million

Table H – Health Risk Impacts – Auxiliary Boiler

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Sensitive	0.03 in one million	7.99 E-05	3.55 E-04	10 in one million [a]	1.0	1.0	No
Worker	0.004 in one million	4.59 E-04	9.42 E-04	10 in one million [a]	1.0	1.0	No

Note: [a] For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million

5. Fumigation Air Quality Analyses

- ✓ Since there are tall stacks along the shoreline, the shoreline fumigation and inversion break-up impacts of the project were analyzed since during these short term events the maximum impacts could be higher.
- ✓ Both inversion break-up and shoreline fumigation were evaluated in the report for 1-hour NO_2, 1-hour, 3-hour, and 24-hour SO_2, 1-hour and 8-hour CO, and 24-hour PM_{10}. Because these meteorological phenomena do not persist for long periods, only the shorter averaging periods ($\leq$ 8 hrs) should be considered.
- ✓ AERSCREEN (version 15181) was utilized for the analysis. The modeling parameters for the worst-case operating scenarios were used for each of the modeled pollutants and averaging times. AERSCREEN is the model EPA recommends to analyze impacts from inversion break-up and shoreline fumigation. However, AERSCREEN cannot provide results that correspond to the federal ambient air quality standards for NO_2 and SO_2, due to the form of those standards. For these pollutants, the maximum value is reported in the table below instead of the 98th or 99th percentile, respectively.
- ✓ Both inversion break-up and shoreline fumigation impacts, combined with background concentrations, are below the applicable ambient air quality standards.

Table I – Impacts during Normal Operations for Inversion Break-Up – Total Project

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (μg/m³)	Background Concentration [a] (μg/m³)	Total Concentration (μg/m³)	Federal AAQS [b] (μg/m³)	California AAQS (μg/m³)
CO, 1-hr	529	3,435	3,964	40,000	23,000
CO, 8-hr	178	2,519	2,697	10,000	10,000
NO_2, 1-hr	85.3	142.3	227.6	-	339
SO_2, 1-hr	5.5	23.1	28.6	-	655
SO_2, 3-hr	5.3	23.1	28.4	1,300	-

Note: [a] Maximum values for CO, NO_2, and SO_2 from SRA 18, North Coastal Orange County (No. 3195) monitoring station and PM_{10} from SRA 19, Saddleback Valley (No. 3812) monitoring station for the last three years (2012-2014).
[b] Both the California and Federal AAQS values listed are not to be exceeded. The federal NO_2 and SO_2 standards cannot be evaluated with AERSCREEN due to the form of those standards and are not considered in this analysis.

Table J – Impacts during Normal Operations for Shoreline Fumigation – Total Project

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (μg/m³)	Background Concentration [a] (μg/m³)	Total Concentration (μg/m³)	Federal AAQS [b] (μg/m³)	California AAQS (μg/m³)
CO, 1-hr	125	3,435	3,560	40,000	23,000
CO, 8-hr	38	2,519	2,557	10,000	10,000
NO_2, 1-hr	47.2	142.3	189.5	-	339
SO_2, 1-hr	3.5	23.1	26.6	-	655
SO_2, 3-hr	3.6	23.1	26.7	1,300	-

Note: [a] Maximum values for CO, NO_2, and SO_2 from SRA 18, North Coastal Orange County (No. 3195) monitoring station and PM_{10} from SRA 19, Saddleback Valley (No. 3812) monitoring station for the last three years (2012-2014).
[b] Both the California and Federal AAQS values listed are not to be exceeded. The federal NO_2 and SO_2 standards cannot be evaluated with AERSCREEN due to the form of those standards and are not considered in this analysis.

6. Modeling Review of Project Impacts for CEC's CEQA Evaluation

- ✓ The modeling report was prepared by the project applicant as part of an Addendum to a previously approved Final Staff Assessment (FSA) for the California Energy Commission (CEC). An FSA is the CEC's CEQA document prepared under its certified regulatory program. PRDAS staff has confirmed the modeling analysis conclusion that the proposed project's impacts do not exceed what was previously approved in the FSA.
- ✓ SCAQMD is both a responsible agency and a commenting agency under CEQA for this project. As noted above in the memo above, the modeling analysis conforms to SCAQMD regulations and SCAQMD does not have any comments as a responsible agency.
- ✓ In order to evaluate the project's air quality impacts for the California Energy Commission's (CEC's) CEQA document, the applicant included a modeling analysis of the impacts from the entire project. The modeling analysis that PRDAS staff reviewed

concluded that the project would exceed SCAQMD PM10 and PM2.5 localized thresholds that are recommended for general CEQA use, but that impacts would be less than significant because the project would provide emission offsets. The impacted area is in an unoccupied area adjacent to the project site (see map at the end of this memo).

- ✓ As a commenting agency, PRDAS staff notes that regional emission offsets should not be used as mitigation for a localized impact. However, as the turbine portion of this project is exempt from analyzing PM10 localized impacts pursuant to SCAQMD Regulation XIII, the SCAQMD PM10 localized CEQA thresholds for general use should only be applied to the boiler portion of the project. The boiler on its own does not exceed SCAQMD PM10 and PM2.5 localized CEQA thresholds.

a. Impacts During Commissioning

- ✓ The two GE 7FA.05 turbines and two GE LMS 100PB turbines are not subject to the modeling requirements of Regulation XIII per Rule 1304(a)(2); therefore the Rule 1303 thresholds do not apply. However, the applicant included a modeling analysis of the impacts from the new turbines and the auxiliary boiler in support of the CEC's CEQA document and PRDAS staff reviewed the modeling in the report.
- ✓ Turbine commissioning is an once-in-a-lifetime event. A total of 6 scenarios were modeled. 3 scenarios were modeled for the two GE 7FA.05's, all of which included the auxiliary boiler in normal operation. 3 scenarios were modeled for the two GE LMS 100PB's, all of which included the auxiliary boiler in normal operation as well. The auxiliary boiler will be installed and commissioned prior to the first fire of the combined-cycle CTGs.
- ✓ NO2 was modeled using the Tier 3 method Plume Volume Molar Ratio Method (PVMRM).
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 5, 6, and 7 of the Engineering Memorandum and are assumed to be correct.

Table K – Impacts during Commissioning for GE 7FA.05 and Auxiliary Boiler in Normal Operation

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (μg/m³)	Background Concentration [a] (μg/m³)	Total Concentration (μg/m³)	California AAQS [b] (μg/m³)	Federal AAQS [b] (μg/m³)
CO, 1-hr	4,341	3,435	7,776	23,000	40,000
CO, 8-hr	3,000	2,519	5,519	10,000	10,000
NO_2, 1-hr [c]	169	142.3	311.3	339	- [d]
NO_2, Annual [c]	0.7	21.8	22.5	57	100
SO_2, 1-hr	6.0	23.1	29.1	655	196 [e]
SO_2, 3-hr	5.1	23.1	28.2	-	1,300
SO_2, 24-hr	1.7	5.2	6.9	105	-
Non-attainment Pollutant & Averaging Time	**Maximum Modeled Concentration (μg/m³)**	**California AAQS (μg/m³)**	**Federal AAQS (μg/m³)**	**Rule 1303 Thresholds [b] (μg/m³)**	
PM_{10}, 24-hr	5.7	50	150	2.5	
PM_{10}, Annual	0.6	20	-	1	
$PM_{2.5}$, 24-hr	5.7	-	35	2.5	
$PM_{2.5}$, Annual	0.6	12	12	1	

Note: [a] Maximum values for CO, NO_2, and SO_2 from SRA 18, North Coastal Orange County (No. 3195) monitoring station and PM_{10} from SRA 19, Saddleback Valley (No. 3812) monitoring station for the last three years (2012-2014).
[b] Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.
[c] The conversion of NO_X to NO_2 was done using the Tier 3 method Plume Volume Molar Ratio Method (PVMRM).
[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 μg/m³). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.
[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 μg/m³). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

Table L – Impacts during Commissioning for GE LMS100 PB and Auxiliary Boiler in Normal Operation

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (μg/m³)	Background Concentration [a] (μg/m³)	Total Concentration (μg/m³)	California AAQS [b] (μg/m³)	Federal AAQS [b] (μg/m³)
CO, 1-hr	527	3,435	3,962	23,000	40,000
CO, 8-hr	131	2,519	2,645	10,000	10,000
NO_2, 1-hr [c]	79.1	142.3	221.4	339	- [d]
NO_2, Annual [c]	0.5	21.8	22.3	57	100
SO_2, 1-hr	5.8	23.1	28.9	655	196 [e]
SO_2, 3-hr	5.0	23.1	28.1	-	1,300
SO_2, 24-hr	1.7	5.2	6.9	105	-
Non-attainment Pollutant & Averaging Time	**Maximum Modeled Concentration (μg/m³)**	**California AAQS (μg/m³)**	**Federal AAQS (μg/m³)**	**Rule 1303 Thresholds [b] (μg/m³)**	
PM_{10}, 24-hr	5.1	50	150	2.5	
PM_{10}, Annual	0.5	20	-	1	
$PM_{2.5}$, 24-hr	5.1	-	35	2.5	
$PM_{2.5}$, Annual	0.5	12	12	1	

Note: [a] Maximum values for CO, NO_2, and SO_2 from SRA 18, North Coastal Orange County (No. 3195) monitoring station and PM_{10} from SRA 19, Saddleback Valley (No. 3812) monitoring station for the last three years (2012-2014).
[b] Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.
[c] The conversion of NO_X to NO_2 was done using the Tier 3 method Plume Volume Molar Ratio Method (PVMRM).
[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 μg/m³). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.
[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 μg/m³). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

b. Impacts During Normal Operations

- ✓ The two GE 7FA.05 turbines and two GE LMS 100PB turbines are not subject to the modeling requirements of Regulation XIII per Rule 1304(a)(2); therefore the Rule 1303 thresholds do not apply. However, the applicant included a modeling analysis of the impacts from the new turbines and the auxiliary boiler in support of the CEC's CEQA document and PRDAS staff reviewed the modeling in the report.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Table 1A, 1B, 2, 3A, 3B, 3C, and 3D of the report and are assumed to be correct.

✓ The applicant will take a permit condition which limits the daily operation of the GE 7FA.05 turbines to no more than 20 hours at 44% load.

Table M– Impacts during Normal Operation – Total Project

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (μg/m^3)	Background Concentration [a] (μg/m^3)	Total Concentration (μg/m^3)	California AAQS [b] (μg/m^3)	Federal AAQS [b] (μg/m^3)
CO, 1-hr	631	3,435	4,066	23,000	40,000
CO, 8-hr	149	2,519	2,668	10,000	10,000
NO_2, 1-hr [c]	94.5	142.3	236.8	339	-
NO_2, 1-hr [c]	-	-	125.4	-	188 [d]
NO_2, Annual [c]	0.6	21.8	22.4	57	100
SO_2, 1-hr	5.8	23.1	28.9	655	-
SO_2, 1-hr	5.4	8.8	14.2	-	196 [e]
SO_2, 3-hr	5.0	23.1	28.1	-	1,300
SO_2, 24-hr	1.7	5.2	6.9	105	-
PM_{10}, 24-hr	4.3	51.1	55.4	-	150
Non-attainment Pollutant & Averaging Time	**Maximum Modeled Concentration (μg/m^3)**	**California AAQS (μg/m^3)**	**Federal AAQS (μg/m^3)**	**Rule 1303 Thresholds [b] (μg/m^3)**	
PM_{10}, 24-hr	4.7	50	150	2.5	
PM_{10}, Annual	0.6	20	-	1	
$PM_{2.5}$, 24-hr	4.7	-	35	2.5	
$PM_{2.5}$, Annual	0.6	12	12	1	

Note: [a] Maximum values for CO, NO_2, and SO_2 from SRA 18, North Coastal Orange County (No. 3195) monitoring station and PM_{10} from SRA 19, Saddleback Valley (No. 3812) monitoring station for the last three years (2012-2014).
[b] Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.
[c] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.
[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 μg/m^3). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.
[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 μg/m^3). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

✓ As shown in Figure 1 below, there are no sensitive receptors located in the area of the modeled exceedance.

Figure 1 – Maximum 24-Hour PM Impact from Normal Operation of the Project ($2.5\ \mu g/m^3$ Contour)

Modeling staff spent a total of 180 hours on this review. Please direct any questions to Jillian Wong at Ext. 3176.

cc: Chris Perri
JW:MS

Appendix V

Public Notice

SCAQMD provided the initial notice and related documents to the following recipients:

To	Contact
AES HB[1]	Steven O'Kane
CEC[1]	Eric Veerkamp
USEPA[1]	Gerardo Rios
HB Library[1]	Mary Wilson
CARB	Tung Le
National Park Service	Tonnie Cummings
National Park Service	Don Shepherd
Forrest Service Region 5	Andrea Nick
US Forrest Service	Randy Moore
County of Orange	Michael Giancola
City of HB	Fred Wilson
SCAG	Jacob Lieb
San Diego APCD	Robert Kard
Antelope Valley AQMD	Eldon Heaston
Mojave AQMD	Eldon Heaston
Ventura County APCD	Michael Villegas
Imperial County APCD	Brad Poiriez
San Joaquin APCD	Seyed Sadredin
Pala Band of Mission Indians	Robert Smith
Perchanga Band of Luiseno Mission Indians	Marc Macarro
CBE	Bahram Fazeli
NRDC	Ramya Sivasubramanian
Coalition for Clean Air	Dr. Joeseph Lyou
California Safe Schools	Robina Suwol

All contacts receive the public notice

1- These contacts also receive the PDOC and the Draft Permit

Additionally, SCAQMD sent the notice to a list of individuals who had previously indicated an interest in receiving Title V notices for facilities in the area. The list of those recipients is included in the file for reference. The notice was published in the OC Register on June 9, 2016, and made available on SCAQMD's website.

AES mailed the notice to all addresses with ¼ mile of the facility on June 16, 2016.

SCAQMD also re-noticed the project. The re-notice was sent to the following recipients:

To	Contact
AES Huntington Beach[1]	Steven O'Kane
CEC[1,2]	John Heiser
USEPA[1]	Gerardo Rios
Huntington Beach Public Library[1]	Mary Wilson
CARB	Tung Le
Forest Service Region 5	Andrea Nick
US Forest Service	Randy Moore
City of Huntington Beach	Fred Wilson
County of Orange	Michael B. Giancola
SCAG	Linjin Sun
SCAG	Jason Lieb
National Park Service	Don Shepherd
National Park Service, Pacific West	Tonnie Cummings
San Diego APCD	Robert Kard
Antelope Valley AQMD	Bret Banks
Mojave Desert AQMD	Brad Poiriez
Ventura County APCD	Michael Villegas
Imperial County APCD	Reyes Romero
San Joaquin Valley APCD	Seyed Sadredin
Pala Band of Mission Indians	Robert Smith
Pechanga Band of Luiseno Mission Indians	Marc Macarro
CBE	Bahram Fazeli
NRDC	Ramya Sivasubramanian
Coalition for Clean Air	Dr. Joseph Lyou
California Safe Schools	Robina Suwol
US Department of the Interior	Christine Lehnertz
State Water Resources Control Board	Felicia Marcus
California Regional Water Quality Control Board, Region 4	Samuel Unger
California Regional Water Quality Control Board, Region 8	Kurt V. Berchtold
Cal OSHA	Juliann Sum
Department of Water Resources	Mark W. Cowin
California Coastal Commission	John Ainsworth
Morongo Band of Mission Indians	Robert Martin
Agua Caliente Band of Cahuilla Indians	Jeff Grubbe
Ramona Band of Cahuilla	Joseph Hamilton
Augustine Band of Cahuilla Indians	Mary Ann Green
San Manuel Band of Serrano Mission Indians	Carla Rodriguez
Cabazon Band of Mission Indians	David Roosevelt
Santa Rosa Band of Cahuilla Indians	John Marcus
Cahuilla Band of Mission Indians	Luther Salgado
Soboba Band of Luiseno Indian	Scott Cozart
Torres-Martinez Desert Cahuilla Indians	Mary L. Resvaloso
Twenty-Nine Palms Band of Mission Indians	Darrell Mike
California Public Utilities Commission	Timothy J. Sullivan

Commenter (Helping Hands Tools)	Rob Simpson
Commenter (member of the public)	Bob Sarvey
Commenter (member of the public)	Jan Tyrell

All contacts receive the public notice

1- These contacts also receive the PDOC and the Draft Permit

2- The CEC letter was not re-sent. The re-notice was docketed on CEC's website on 11/10/16

Additionally, SCAQMD sent the notice to a list of individuals who had previously indicated an interest in receiving Title V notices for facilities in the area. The list of those recipients is included in the file for reference. The notice was published in the OC Register on November 17, 2016, and made available on SCAQMD's website.

AES mailed the notice to all addresses with ¼ mile of the facility on November 15, 2016.

Appendix W

Comments and Responses

A total of 4 comment letters were received after the initial PDOC was released to interested parties, the public, and agency contacts. Three comment letters were from members of the public, and one was from AES .

Following are the comments and responses from SCAQMD.

Any new comments that are received during the re-noticing period will be addressed, and the comments and SCAQMD responses will be included in this document.

Commet Letter No. 1

I as a resident living across the street from the AES Huntington Beach facility ID #115389 have a request and or a question. Will there be regulated check on the air quality in and around the site for the length of the project? If not can this be done, with results (if not cleared) sent to all living nearby as a warning, ASAP?

Whehn the old facility is taken down, will a tent be placed over it with vacuum system to clean pollutants from the air? We as a nearby resident home owner have a lot of concern about the air quality. Thank you for your info you provided but I want some assurance that air quality will be checked regularly throughout construction.

Response to Comment Letter No. 1

Two SCAQMD rules in particular are intended to minimize emissions related to construction and demolition projects, SCAQMD Rules 403 and 1403. Rule 403 (Fugitive Dust) requires water sprays on dirt roads and any areas of exposed soil, the washing of construction vehicles before they leave the site, along with other measures designed to limit the generation of dust from construction. In addition, any asbestos removal activities are subject to SCAQMD Rule 1403 (Asbestos Emissions from Demolition/Renovation Activities). Rule 1403 outlines the requirements to insure that the removal of asbestos containing materials is done so in a manner which minimizes the release of asbestos into the environment.

Furthermore, our Rules 401 (Visible Emissions) and 402 (Nuisance) may be applicable in cases where construction activities create visible dust clouds or a public nuisance.
Currently there is no plan to monitor the air in and around the site during construction. However, Rule 403 does provide for such monitoring if it is warranted, such as in cases where the PM10 emissions

levels generated by construction activities are suspected to be at or near the rule limit of 50 micrograms per cubic meter. As a side note, the SCAQMD has a toll free number anyone can call to report issues about air quality or odors. The number is 1-800-CUT SMOG (1-800-288-7664).

Responses to Comment Letter No. 2

Comment 1

The CEC Preliminary Staff Assessment (PSA) was recently published. In order for us to effectively participate in both aspects of this proceeding, we need to be informed by both the PDOC and PSA to comment on either document. The PSA is 1184 pages and PDOC is 213 pages. Both are highly technical documents requiring review by our legal, engineering and executive team. We request that when you do publish opening of the comment period you provide at least a 60 day comment period. 30 days is simply inadequate for informed public participation.

We are a small organization without the resources of the CEC and air district. Both of these had ample time to review the application before their preliminary decisions. We have oral arguments before the Ninth Circuit Court regarding a deficient air pollution permit issued by the EPA on July 19th. We have other permits in your area that are open for comments. So it is a very busy time for our staff. We ask that any comment period be extended to well beyond this date.

Please also consider this a public records request and forward all electronic information and communications regarding this proceeding to this email address.

There are a number of areas in which the District may wish to correct the public notice in order to maintain the integrity of the permitting process.

First the Notice reads more like a sales pitch for the project then a notice intended to warn the public of potential hazards. It states;

"This notice is to inform you that the South Coast Air Quality Management District (SCAQMD) has received permit applications from AES Huntington Beach, LLC for the Huntington Beach Energy Project (HBEP) which will consist of the replacement of two existing older and less efficient large electric generating utility boilers with four new state of the art and more efficient electric generating gas turbines."

The district should refrain from claims that the new equipment is "state of the art" This statement and others allude to the new project polluting less than the old project. Because the Notice failed to comport with district Rule 3006 which requires that the notice contain: "(v) The emissions change involved in any permit revision" readers can be misled to believe that the new project would pollute less than the old project. The notice does make claim of "Pollutant Max Potential Emissions" but also states, "The emissions listed below are strictly from the new equipment and do not include any emission reductions associated with the removal from service of the existing electric utility boiler generator Units 1 and 2." And so the "change" is not disclosed.

The notice also fails to disclose 3006 (viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested. Rule 1710 reiterates that SCAQMD must provide the opportunity for a public

hearing on the project. The notice therefore violates 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10
The District has a mandate to prepare the public notice to contain sufficient information to fully describe the project. It fails this mandate, in several places the abbreviation MW is used to describe the project but nowhere is the definition of the term offered. The Notice also contains one reference to the CEC, again without disclosure of the definition. This is particularly problematic because the California Energy Commission is the lead agency for this project with exclusive jurisdiction regarding siting of the facility.
The notice not only fails to disclose the districts position as a responsible agency under CEQA it misdirects the readers to agencies with no jurisdiction over the process, It states. “If you are concerned primarily about zoning decisions and the process by which the facility has been sited in this location, contact the local city or county planning department for the city or unincorporated county in which the facility is located.”
The Preliminary Determination of Compliance (PDOC) states;
“California Environmental Quality Act (CEQA)
The project is subject to the licensing procedure under the California Energy Commission (CEC). This procedure analyzes all aspects of the proposed project, and is subject to a public review and comment
period. It is therefore considered equivalent to an Environmental Impact Report, and satisfies the requirements of CEQA. CEC’s process will fully evaluate all air quality impacts for the entire project.” The
District cannot simply close its record to public comments prior to the district and public having the opportunity to review the CEC EIR equivalent.
. § 15096. Process for a Responsible Agency.
. (a) General. A responsible agency complies with CEQA by considering the EIR or negative declaration prepared by the lead agency and by reaching its own conclusions on whether and how to approve the project involved. This section identifies the special duties a public agency will have when acting as a responsible agency.
When is a Responsible Agency Required to Make Findings?
Where an EIR indentifies one or more significant envrionmental effects, the responsible agency must make findings on each effect.
What Standard Must a Responsible Agency Follow in Making its Findings?
Responsible Agency must make one or more of three findings pursuant to §15091(a).
(1) Changes have been incorporated in the project to avoid or substantially lessen the identified significant environmental effect.
(2) The changes are within the jurisdiction of another agency and the changes have been or should be adopted by that other agency.
(3) Specific considerations which make infeasible the alternatives identified in the final EIR.
Support finding by substantial evidence in the record.
The Agency must present an explanation of the rational of each finding
The applicant docketed a distribution list for the Districts public notice it states. “Mailer's Mailing Date 06/16/2016” If the public comment period was to end at this time the recipients would have much less than 30 days to review the documents.

http://docketpublic.energy.ca.gov/PublicDocuments/12-AFC-02C/TN211930_20160621T162551_AES_HBEP_PDOC_Public_Notice_Verification.pdf
The project proposal has been on the CEC docket for over 4 years. It is unlikely that it will ever be built. An extension of the comment period would create no delays in the projects construction. I will surely have questions on the last day available for comments so if it is to be a Saturday I would hope that the district will be open. The notice provides no email address for delivery of comments. It appears that the district has extended comment periods and provided email addresses for comments in the past. To do otherwise in this instance would appear arbitrary and capricious. If the comments need to be mailed; I am at a particular disadvantage because I am out of the country at this time and beyond the international date line. It also limits the effective comment period to less than 30 days because the notice states that, “Comments must be received no later than July 9, 2016” with no provision for them to merely be postmarked by that date.
The District should correct its notice to comport with the law and extend the comment period until stakeholders have had the opportunity to consider the lead agencies findings. Failing that and while we still contend that the procedure would not comply with CEQA, the comment period should be at least 30 days from publication of the corrected notice.
We request a public hearing to understand the above issues better, build coalition with others opposed to the facility and receive feedback on our comments to be filed.

SCAQMD Response
SCAQMD is required to publish a public notice for a project such as this under Regulation XXX (Title V), Regulation XVII (Prevention of Significant Deterioration, or PSD) and Rule 212. The requirements for noticing under each of these rules is somewhat overlapping and SCAQMD often drafts one notice to cover the requirements of all three regulations. The notice is published in a newspaper in the vicinity of the project, mailed to multiple environmental and government agencies and interested parties, and distributed to residents that live within ¼ mile of the facility. Project documents are also made available at a local library and at SCAQMD’s office in Diamond Bar, and on the SCAQMD website.
In most cases, the newspaper publication date is different from the date in which the notice is mailed to residents due to logistics. However, each recipient is given at least 30 days to provide comments and each notice indicates the deadline for submitting comments.
The SCAQMD published the newspaper notice regarding the preliminary determination of compliance for this project on June 9, 2016. The notice provided for a 15 day period to request a public hearing, and 30 days to provide comments. The deadline for requesting a public hearing expired on June 24, 2016, as stated in the notice. The 15 day period for public hearing requests is set by rule 3006(a)(1(F). Furthermore, a public hearing request must be accompanied by the submittal of a 500G Form, as stated in the notice. The form requires inclusion of information justifying the request for public hearing under Rule 3006. Since the deadline has passed and a 500G Form was not submitted, we therefore cannot grant your request for a public hearing. The 30 day comment period for the newspaper notice ended on July 9, 2016 as stated in the notice.
The local resident (1/4 mile) notification for the project was mailed out on June 16, 2016, indicated on the last page of the notice as the ‘distribution date’. The notice states “Comments must be received within 30 days of the distribution date”, which would have been July 16, 2016.

Rule 3006(a)(1)(D) requires the notice period to be at least 30 days, although it can be longer. In the case of HBEP however, SCAQMD did not find it necessary to provide an extended comment period. We believe the 4-page public notice satisfied the SCAQMDs obligation to provide sufficient detail to describe the project, the location, the project's emissions, the public comment procedures, and contact information.
The CEC's analysis of the proposed project incorporates SCAQMD's findings concerning air quality. The CEC generally releases their Preliminary Determination of Compliance (PSA) after the air district publishes its preliminary air quality analysis. This PSA was published on June 2, 2016 for a 30-day public comment period. Thus, public is provided multiple opportunities to comment on the project, both through the air district's noticing process, as well as the CEC's permitting process.
In this particular case, after consideration of issues related to public notice, the SCAQMD has decided that a re-notice for this project to the addresses within ¼ mile of the facility is warranted after it became evident that these notice recipients may not have had their full 30 days to comment. SCAQMD has also re-noticed this project in the local newspaper on November 17, 2016, so that all commenters have a chance to review our analysis in conjunction with the CEC's Preliminary Staff Assessment of the project.

Comment 2
When deliberating whether to provide legally effective public notice the district should review the EPA Environmental Appeals Board (EAB) decision, in my favor, regarding the Russell City Energy Center failure to adequately provide effective public notice of proposed permitting actions.

SCAQMD Response
SCAQMD has reviewed the decision and determined that the issues involved in that case are not relevant here, because SCAQMD has not relied exclusively on the CEC notice process for the HBEP. Also, see response to Comment 1. We will be re-issuing our notice both to insure all commenters have at least 30 days to comment, and so that our analysis can be reviewed along with the CEC's draft CEQA (PSA), which has already been released for public review.

Comment 3
The PDOC states;
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 30 of those acres.
The District should determine in its BACT analysis how much solar power could be developed on the parcel and in other locations to help control GHG and other emissions from the facility. Solar thermal or Photovoltaics (PV) could help heat the boilers, charge batteries or condensers, feed directly to the grid, smooth output, or even to generate Hydrogen gas and oxygen to increase thermal efficiency while reducing emissions. These all must be considered in the districts BACT analysis. The District should identify the business purpose of the facility as to generate electricity for sale as a basis for determining what control measures might interfere with that purpose. The District should consider the Palmdale Energy Center PSD permit and the EPA response to my comments;

"we find it appropriate to clearly state that the solar component is a lower-emitting GHG technology at this facility. Because the solar component is integrated into the heat recovery portion of the project, it has the potential to reduce GHG emissions by reducing use of the duct burners during peak energy demand. The Project, as described in the application, includes the development of 50 MW of solar energy. As an integrated part of the Project with the ability to reduce GHG emissions, we consider the solar component to be part of the GHG BACT determination for the combustion turbines and associated heat recovery system. In addition, the permit has been revised to ensure that the solar component is a required part of the facility."
https://www.regulations.gov/document?D=EPA-R09-OAR-2011-0560-0058

SCAQMD Response

Solar power was considered as an alternative to the proposed turbines. The use of solar power at the location of the Huntington Beach plant was determined to not be a viable alternative due to space limitations and lack of adequate solar resources. These conclusions hold true for use of solar power for auxiliary purposes as well. According to the National Renewable Energy Laboratory (NERL) Land Use Requirements for Solar Power Plants in the US, June 2013, it takes approximately 8 acres of total land per 1 MW of capacity for solar PV type installations. Accordingly, the 30 acres of land that the HBEP would be built on would be capable of providing room for less than 4 MW capacity. This is equivalent to about 10 GW-hrs/yr, which is only a fraction of the 4,000+ GW-hrs/yr the gas fired plant is designed to produce. Note that the additional land at the site where the switchyard equipment and tank farm is located is not currently owned by AES, and even if it were, it still would not provide enough space to make solar feasible. Also note that the turbines proposed for the HBEP do not use duct burners.

This lack of space and proximity to the ocean (which often times results in conditions causing a marine layer and hence low solar energy) makes the prospect of generating a meaningful and consistent amount of solar energy at the site unlikely. The use of solar as an alternate and add on to the proposed gas turbines has been extensively covered in the CEC PSA.

Comment 4

The PDOC states; "The boilers are equipped with SCR systems, and are fired primarily on pipeline natural gas, with some field gas from offshore platforms also combusted. The proposed new facility will be composed of two separate power blocks, a combined cycle block and a simple cycle block. Construction of the combined cycle block is expected to begin in the second quarter of 2017 (outside of some demolition activities and site prep), and construction of the simple cycle block is anticipated in the second quarter of 2022. First fire of the combined cycle power block is expected by 10/1/2019. The District should disclose the effect on emissions resulting from the use of field gas and imported gas plus the likelihood of increase in their use over the life of the project to determine potential emissions from the project. The District should not close the public out of the opportunity to comment in 2016 for a project that is, at best case scenario, projected to commence construction in 6 years. Laws are changing, the environment is being depleted and the public has a right to participate in these matters that affect them.

SCAQMD Response

Although existing boiler units are occasionally fired on a mixture of natural gas and field gas from offshore oil wells, the new turbines will use pipeline natural gas only. The emissions from natural gas firing for the new turbines have been fully disclosed in the PDOC. Also see the response to Comment 10 for discussion regarding the timing of the permit issuance and equipment construction.

Comment 5

The PDOC states;
California Environmental Quality Act (CEQA)
The project is subject to the licensing procedure under the California Energy Commission (CEC). This procedure analyzes all aspects of the proposed project, and is subject to a public review and comment period. It is therefore considered equivalent to an Environmental Impact Report, and satisfies the requirements of CEQA. CEC's process will fully evaluate all air quality impacts for the entire project.
The District must at least participate in the CEC process and provide its opinion of the CEC pending Members Proposed Decision (PMPD) so that the public can comment on the districts Preliminary decision in light of the environmental review, prior to the lead agency making its decision. It is entirely inappropriate to close the public participation opportunity prior to the environmental review.

SCAQMD Response

The public participation opportunity is not closed after SCAQMD issues its notice. The CEC process is still ongoing and there are many opportunities for the public to participate in this proceeding (http://www.energy.ca.gov/sitingcases/huntington_beach_energy/). Furthermore, SCAQMD does participate in the CEC process, providing comments when deemed necessary (as an example, see Appendix U of the PDOC for SCAQMD's review of the air quality analysis for this project).
Also, see response to Comment 1. We will be re-issuing our notice in part so that commenters have the opportunity to review our analysis along with the CEC's draft CEQA (PSA), which has already been released for public review.

Comment 6

The PDOC states; "Simple cycle Auxiliary Boiler The simple cycle turbines do not require steam condensing, since they do not use heat recovery. The only cooling associated with the simple cycle turbines is the use of a fin fan air cooler to cool the water used in the intercooler.
Simple Cycle turbines are simply not BACT. Heat should at least be discharged to the planned boilers The ditrict must consider Cogeneration opportunities and require the turbines to be combined cycle.

SCAQMD Response

AES proposed the use of 2 simple cycle units in conjunction with a combined cycle plant for the HBEP based on the planned operational profile of the plant. The simple cycle units provide some unique operating attributes compared to combined cycle units, including quicker starts and ramping ability. Requiring only the use of combined cycle units would hamper the ability of the facility to meet its operational needs. Furthermore, the BACT analysis is not intended to require the applicant to change its design from construction of a combined cycle plant to a simple cycle plant (See, e.g., In re Kendall New Century Development, PSD Appeal No. 03-01, 11 E.A.D. 40, 51-52 (EAB 2003)

(finding that, in identifying BACT for a proposed peaking generating facility, the permitting authority "does not have authority to require [the Applicant] to construct a facility with larger combustion units or one that would run in combined-cycle mode since this would change the intended nature of the Facility"), along with other recent EPA EAB decisions supporting the same conclusions(Pio Pico Energy Center PSD Appeal Nos. 12-04 through 12-06.
Designing a system to direct exhaust heat from the simple cycle turbines to the auxiliary boiler would result in a loss of efficiency from the turbines. Additionally, since the simple cycle turbines are designed to provide quick starts and peaking power for short durations, the amount of heat they could provide to the boiler is minimal.

Comment 7
The PDOC states;
There are no evaporative water cooling towers associated with this project, the combined cycle turbines will be air cooled
The District cannot simply adopt other agencies basis for recommending against wet or other cooling without making its own independent determination of the basis' effect on air quality. Form an air quality standpoint dry cooling is the least favourable method. Therefore the district must either weigh the other agencies concerns against wet cooling compared to the air quality benefits or simply require the more efficient wet cooling.

SCAQMD Response
The use of wet cooling was considered as an alternative approach to dry cooling for HBEP. The wet cooling option was not deemed suitable because the use of potable water would strain already existing water supply issues, while the use of reclaimed water would require a new pipeline into the facility and a new treatment facility. Use of wet cooling also results in emissions of particulates, especially with the use of reclaimed water which is relatively high is dissolved solids. Therefore the project proponent chose dry cooling as the preferred method. Also, it should be noted that the SCAQMD does not require permits for the cooling towers.

Comment 8
The PDOC states; "The applicant is requesting that the project be evaluated under the Rule 1304(a)(2) – Electric Utility Steam Boiler Replacement exemption. This provision applies to the replacement of a utility steam boiler with combined cycle gas turbine(s), or other advanced gas turbines (including intercooled turbines), and allows an exemption from the criteria pollutant modeling required under Rule 1303(b)(1), and from offsets for non-Reclaim pollutants required under Rule 1303(b)(2) in such cases.
The simple cycle turbines do not comport with the intent or letter of the afore mentioned rule and so should not be exempted.

SCAQMD Response
To qualify for the offset and modeling exemption of Rule 1304(a)(2), the new turbines are required to be either combined cycle units, or "intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy…" The GE LMS100 simple cycle units proposed

for HBEP are intercooled turbines (see page 16 of the PDOC), and therefore qualify for the exemption. Intercooled turbines use water in the compressor section of the turbine as a means to cool the exhaust gas to increase power output and efficiency, which results in less emissions per unit of power output.

Comment 9

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

The public notice must contain this information. There is nothing in the notice about increased emissions or emission banking. I was also under the impression that the RECLAIM program was overturned by the courts but my legal team has not had an opportunity to review the PDOC because the comment period was inadequate.

SCAQMD Response

The notice does in fact contain information about emissions from the HBEP, and the offset sources for those emissions increases (please refer to the "Emissions" section of the notice). The notice states that the project is exempt from offsetting for VOC and PM10 under Rule 1304(a)(2), that no CO offsets are required because CO is in attainment, that the NOx and SOx emissions will be offset through RECLAIM, and that PM2.5 offsets are not required because the facility is under the offset threshold. Furthermore, the RECLAIM program has not been overturned by the courts and continues to be fully effective. The SCAQMD "emissions bank" is the program administered under SCAQMD Rule 1315 and is distinct from "emissions banking" by private sources of ERCs. The SCAQMD "bank" primarily consists of "orphan" shutdown emissions reductions from facilities that do not apply for or are not eligible for obtaining ERCs.

Comment 10

The PDOC states;

BACT is required for all criteria pollutants and ammonia. For major sources, BACT is determined at the time the permit is issued, and is the Lowest Achievable Emission Rate (LAER), which has been achieved in Practice.

This procedure stifles public participation if BACT is actually determined perhaps years in the future but the public opportunity to comment ends today.

SCAQMD Response

For major stationary sources, BACT is determined at the time the permit is issued. The permit is valid for one year under SCAQMD's rules. The facility is also subject to federal regulation 40CFR 52.21 which provides for an 18 month period for the commencement of construction, with no more than 18 months of construction inactivity.

HBEP is a multi-year construction project that will be built in two phases. Phase 1 will consist of the combined cycle turbines and auxiliary boiler and Phase 2 will consist of the simple cycle turbines. Estimated start of construction for Phase 1 is 2nd quarter 2017, and estimated start of construction for

Phase 2 is 2nd quarter 2022. For phased projects, each phase must begin within 18 months of the planned date for the start of construction.
The applicant will need to obtain permit extensions from SCAQMD as the project moves forward. During the review of the extension requests, and in consideration of the status of the construction process, the SCAQMD has the authority to make a determination that a new BACT/LAER standard for the equipment is warranted and to also determine the applicability of any new standards that may have been adopted since the original permit was issued.(Security Environmental Systems v. SCAQMD 229 Cal.App.3d 110).
Additionally, for phased projects, pursuant to EPA guidance and discussions with EPA, within 18 months prior to the commencement of construction of each phase, SCAQMD can review its permitting decision. SCAQMD will determine if a re-analysis of BACT or other rules or regulations is necessary.

Comment 11
The PDOC states;
Alternative Analysis. The project is subject to the California Energy Commission licensing procedure. Under this procedure, a full analysis of the proposal is conducted, including project alternatives. The alternative project analysis was conducted under the previous HBEP AFC in 2012
The District cannot simply rely on flawed alternative analysis for a prior proposed project or one to be completed by another agency. It must either complete its own analysis or provide the public with an analysis for comment prior to its curtailment of public participation. There are better locations and superior alternatives which I would discuss further given additional time to comment and an actual germane analysis

SCAQMD Response
SCAQMD is not relying on a prior CEC analysis, but is required, as a responsible agency, to rely on the CEC's current CEQA analysis. Furthermore, Rule 1303(b)(5)(D)(iii) allows the SCAQMD to rely on an alternative analysis conducted as part of a CEQA process. This rule has been approved by EPA in the State Implementation Plan (61 FR 64291, 12/4/96). As the lead permitting agency, the CEC conducts an in-depth review of environmental and other issues posed by the proposed power plant. This comprehensive environmental review is the equivalent of the review required for major projects under the CEQA, and the Energy Commission's license satisfies the requirements of CEQA for these projects. The necessary alternative analysis was conducted under the CECs current review process. The commenter is encouraged to participate in the CEC's current licensing process. The location of a project is outside of the preview of the SCAQMD and its jurisdictions.

Comment 12
The PDOC states;
Rejected because of space limitations and lack of sufficient solar resources AES also considered wet cooling using either potable or recycled water, or seawater, as an alternative to the proposed dry cooling of the turbines. This was rejected because in the case of potable water, its use for power plant cooling purposes is discouraged by SWRCB and the CEC. In the case of recycled water, an additional pipeline and treatment facility would need to be constructed to supply enough water at the

required level of treatment to serve the plant. The seawater option was rejected because of the environmental impacts of a seawater intake pipe, and cost considerations.
The District should consider nuanced solar components not a simple all or nothing option and wet cooling for the reasons cited above.

SCAQMD Response
See response to Comment 3

Comment 13
The PDOC states;
An alternative to the proposed site of the power plant was determined to be not necessary because PRC 25540.6 [b] states that if the commission finds 'that the project has a strong relationship to the existing industrial site' …..'it is therefore reasonable not to analyze alternatives sites for the project'. PRC 25540.6 [b] does not excuse the District from its duty to consider alternative sites. The district must conduct the analysis to comply with its mandated state and federal laws.

SCAQMD Response
See response to Comment 11

Comment 14
The PDOC states;
RULE 1325/40CFR 51 Appendix S – Federal PM2.5 New Source Review
Rule 1325 is the New Source Review rule for PM2.5 and its precursors, NOx and SO2. This rule applies to new major polluting facilities, major modifications to existing major polluting facilities, or any modification to an existing facility that would constitute a major polluting facility in and of itself. A major polluting facility is defined as a facility located in a federal non-attainment area which has actual emissions, or a potential to emit of greater than 100 tons per year, of either PM2.5 or its precursors. Note that EPA recently re-classified the South Coast basin as serious non-attainment for PM2.5. This effectively reduces the major source threshold from 100 tons per year to 70 tons per year. However, the reclassification does not take effect until August 14, 2017, or earlier if SCAQMD adopts the revised threshold by amending this rule prior to that date.
Because this date is prior to proposed construction and because the district failed to consider the effect of fugitive ammonia emissions in its PM analysis the district must re-evaluate its analysis

SCAQMD Response
SCAQMD can only review the project under rules currently in at the time the permit is being issued. In the case of the PM2.5 rule, the new threshold limit does not take effect until August 17, 2017, or when EPA approves the rule amendments, whichever occurs later. If the permit is still under review at such time, or if the situation arises where construction has not commenced and a permit extension is requested, the new threshold limits will be evaluated as they pertain to the emission levels of the HBEP. However, it is important to note that HBEP project is expected to be under even the proposed 70 tpy PM2.5 major source threshold.

SCAQMD demonstrated in its SIP approval for Rule 1325 (Federal PM2.5 New Source Review) that major stationary sources of ammonia do not contribute significantly to the formation of PM2.5. The EPA has agreed, as stated in Federal Register /Vol. 80, No. 84 / Friday, May 1, 2015, Section III.1. Therefore, existing Rule 1325 does not apply to ammonia emissions.
Amended Rule 1325 will include ammonia as a precursor to PM2.5 effective August 17, 2017, or when EPA approves the rule, whichever is later. If the permit is still under review when the amended rule becomes effective, ammonia emissions will be considered at that time.

Comment 15
The PDOC states;
there will be a significant increase and significant net increase in NOx resulting from the proposed modification (the significant increase threshold is 40 tpy for NOx based on new PTE vs. existing actual).
Therefore, the HBEP is considered a major modification to an existing major source for NO2 and is subject to NSR under this rule for NOx only. The project is also considered a major modification for NOx under
SCAQMD Rule 2005 and Regulation XVII (PSD), and as such, all of the requirements listed above have been addressed under those rules.
This information must be in the public notice.
The PDOC states;
The South Coast Basin where the project is to be located is in attainment for NO2, SO2, CO, and PM10 emissions. Additionally, beginning on January 2, 2011, Greenhouse Gases (GHGs) are a regulated criteria pollutant under the PSD major source permitting program. Therefore each of these pollutants must be evaluated under PSD for this project.
The PDOC states;
If the facility is deemed to be major, Rule 1702 further defines a major modification as a significant emission increase of 40 tpy or more of NO2 or SO2, 15 tpy of PM10, or 100 tons per year or more of CO (determined on a new PTE vs. existing actual basis). The existing equipment at the Huntington Beach Generating Station is a major source for NOx, CO, and GHGs, but not PM10 or SOx. Furthermore, with the addition of the new equipment, there is a significant increase of NO2 and GHG but not CO, and therefore, a PSD review is required for NOx and GHGs. Finally, the addition of the new gas turbines does not constitute a major source in and of itself for PM10 or SOx.
This information must be in the public notice.

SCAQMD Response
We believe the 4-page public notice for the HBEP contained sufficient details to describe the project, the location, the project's emissions, the public comment procedures, the procedures for requesting a public hearing, and contact information. For those interested in obtaining further information on the project, such as the details cited in your comment, the notice contained clear instructions on how to access SCAQMD's complete engineering analysis and the facility permit details, through the local Huntington Beach Public library, or at SCAQMD headquarters. Additionally, all documents were made available on the SCAQMD website, and the public notice contained detailed instructions on

how to obtain this information from our website. The District believes that it has provided more than sufficient information in its public notice.

Comment 16
XONONTM
SCR
EMx
SNCR
The district failed to consider the above technologies on subsequent steps in its BACT analysis

SCAQMD Response
The technologies listed were considered in the top down analysis for the turbines, along with water injection and dry low NOx (DLN) combustion. The facility selected DLN combustion and SCR to meet the NOx BACT limit for the turbines. Please refer to pages 52-54 of the PDOC.

Comment 17
The PDOC states;
For the NO2 cumulative impact assessment, three facilities, Orange County Sanitation District's Huntington Beach and Fountain Valley facilities and Beta Offshore as well as emissions from shipping lane activities off the coast were selected to be included based on their facility emissions and distance to the project. Seasonal, by hour-of-day background concentrations from the Costa Mesa monitoring station were used in the modeling. Following the form of the standard, the 1-hour NO2 impact from the project plus cumulative sources plus background is 148 ug/m3, which is less than the Federal 1-hour standard of 188 ug/m3. Therefore, no additional PSD analysis is necessary.
The cumulative assessment should include local roads, highways and other sources.

SCAQMD Response
The cumulative assessment includes nearby sources (OC Sanitation District Huntington Beach and Fountain Valley, Beta Offshore, and shipping lanes), expected to cause significant concentration gradients in the vicinity of the source in question. The modeled impact from these sources is added to the background concentrations. The background concentrations take into account natural sources, other nearby sources, and unidentified sources. Emissions from local roads and highways and other sources are represented in the background concentrations, so modeling these sources separately would effectively double count their emissions. The selection of the background monitor and the appropriate nearby sources to include in the cumulative impacts modeling was done in consultation with modeling staff at US EPA Region 9 and following the guidelines set forth in Appendix W and the modeling guidance memos released by the US EPA OAQPS.

Comment 18
The PDOC states;
Step 1 The available CO2 control technologies are:
A. Carbon Capture and Sequestration (CCS)
B. Thermal Efficiency

The list is woefully inadequate in addition to the solar, battery and combined cycle recommendations above; the district should consider biosequestration in algae water at the site and other appropriate locations.
"The Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has selected 16 projects to receive funding through NETL's Carbon Capture Program."
http://energy.gov/fe/articles/doe-selects-16-transformational-carbon-capture-technologies-projects-funding
Sequestration of CO2 Emissions
There are several sequestration approaches.
The PDOC states;
The following factors affect the thermal efficiency of a power plant:
Thermal dynamic cycle selection, combined cycle versus simple cycle
The PDOC states;
It is technically infeasible for the carbon capture systems to start up and shut down or to make large adjustments in gas volume in the time frames required to serve this type of operation. The CCS system could operate at minimum load during periods of expected operation. However, this approach would consume energy, offsetting some of the benefit.
The district gave short shrift to CCS there should be a quantification of how much energy and offset would be caused by operational changes and at what threshold the determination of infeasibility is met. There is no demonstration of infeasibility.

SCAQMD Response
SCAQMD believes that carbon capture and storage was adequately considered in the GHG BACT determination. Although the analysis contained in the PDOC provided evidence that CCS is not technically feasible for the HBEP project, it was carried forward in the analysis as a potential GHG control technology. In Step 4 of the analysis, the economic feasibility of carbon capture was assessed. The conclusion was that if carbon capture were feasible and commercially available, it would increase the cost of the Huntington Beach Energy Project (HBEP) by approximately 50 percent, not including the cost associated with transport and sequestration of the captured carbon dioxide (CO2). This is supported by a California Energy Commission Report (CEC-500-2015-002), which found that deploying carbon capture on new natural gas combined-cycle plants increases costs by a factor of over 2 times.
The use of bio-sequestration of carbon in algae producing pools is an emerging technique for control of CO2 from power plants. It involves the use of an algae bioreactor wherein photosynthesis is promoted by the addition of exhaust gas CO2. However, the technique is still in its infancy and the District believes that it is not feasible as an add-on control at this time. Most of the pilot scale and research projects undertaken to date have involved coal fired power plants (Algae Tec and Bayswater Power Station, Australia, RWE and Niederaussem Power Plant, Germany, Seambiotic and Rutenberg Power Station, Israel, Arizona Public Service Company and GreenFuel Technologies Corp, USA), with very few focusing on natural gas fired plants (EniTecnologie, Italy) source: Microalgae Removal of CO2 from Flue Gas, Xing Zhang, April 2015 These projects do not indicate that bio-sequestration through algae pools would be feasible for this project.

Comment 19

The PDOC states;

The basic technologies required for CO2 transportation (i.e., pipeline, tanker truck, ship) are in commercial use today for a number of applications and can be considered commercially available for liquid CO2. However, the Task Force report shows that there are no existing CO2 pipelines in California. Any new pipeline constructed for HBEP would need to not only overcome technical issues such as high pressures design (> 2,000 psig) and corrosion resistance, but also the issues of obtaining the necessary permits and right-of-way agreements.

Again no adequate data or demonstration of infeasibility.

SCAQMD Response

The SCAQMD's GHG BACT analysis in the PDOC concluded that the carbon capture technology was not economically feasible based on the estimated capital cost of a CCS system for the HBEP, therefore assessing the feasibility and cost of a CO2 pipeline is not necessary. However, if carbon capture were economically feasible for the HBEP, the most realistic scenario could be to construct a pipeline from the Huntington Beach area to either the Santa Fe Springs or Dominquez Hills oil fields near Los Angeles for enhanced oil recovery (EOR), assuming that permits and right-of-way agreements are obtained and that there are active EOR operations in these locations. The distance for a pipeline to either of these two fields is approximately 30 miles. Based on engineering analysis by the designers of the Denbury CO2 pipeline in Wyoming, costs for an 8 inch CO2 pipeline are estimated at $600,000 per mile, for a total cost of $18 million. This does not include the costs associated with obtaining rights-of-way and the necessary approvals, which likely would be significant. Costs could be substantially higher to transport CO2 to deep saline aquifer or ocean storage locations. SCAQMD cannot require he project to use CO2 technologies that could only be implemented after years of deliberations if at all, and at undetermined expense.

Comment 20

The PDOC states;

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 fields. Therefore CCS using geological sequestration cannot be demonstrated to be technically feasible in practice for the new power generating system.

The district must provide the data so that the public can comment on its determination. What are the estimates? The district cannot turn the BACT analysis on its head and eliminate control measures that it claims "cannot be demonstrated to be technically feasible" instead of the BACT dictate to "Eliminate technically infeasible options"

SCAQMD Response

As noted in the response to Comment 19, the GHG BACT analysis concluded that carbon capture is not feasible for the HBEP based on cost considerations, and not technologically aspects. Furthermore, construction of a CO2 pipeline to sequester CO2 via EOR only increases the economic infeasibility of carbon capture.

In support of its GHG BACT determination, the project proponent provided a review of the technological aspects of carbon sequestration, including a discussion of the Wilmington Graben project. The Wilmington Graben project is an ongoing comprehensive research program for characterization of the potential for CO2 storage in the Pilocene 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 analysis. According to the study, it is estimated that these sediments have the capacity to store over 50 million tons of CO2. However, no pilot studies of CO2 injection into onshore or offshore geologic formations in the vicinity of the HBEP site have been conducted to date. While this study supports the argument that carbon sequestration may eventually be feasible, it also highlights the fact that no full scale projects have been undertaken yet, and there are many issues that remain to be resolved. Furthermore, the operational profile of the HBEP turbines will require frequent starts, stops, and load changes which adds to the technical challenges of implementing CCS for this plant. Therefore, SCAQMD concludes that geological sequestration is not technically feasible for this project at this time

Comment 21

The PDOC states;

Summary of CCS Feasibility

In summary, the post-combustion carbon capture technologies are still in the developmental stage or pilot scale projects. These technologies would not be considered commercially available for the project size of a full-scale commercial power plant. In addition, there are no comprehensive standards in place defining requirements for long term sequestration. Therefore, CCS is not yet demonstrated in practice for a commercial-scale, natural gas fired power plant such as the HBEP. In consideration of the uncertainty in the technical feasibility of CCS and its emergence as a promising technology, CCS is carried forward in this BACT analysis as a potential GHG control technology.

However, substantial evidence demonstrates that CCS is not yet demonstrated as technically feasible for the HBEP project.

The district should not override the EPA with its opinions or turn the BACT analysis inside out with foregone conclusions.

Step 4 of the BACT analysis is to evaluate the most effective control. This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down approach requires that the evaluation begin with the most effective technology. Although carbon control has been deemed infeasible for the HBEP, in response to a suggestion from EPA team members on other recent projects, the economic feasibility of CCS was still evaluated by AES in this step

The analysis focuses on cost but not value. The analysis should contain a discussion of the value of sequestration not just on a saving the planet scale but what is the value of sequestration compared to the cost of carbon or carbon tax? What is the value to oil field operators of carbon for increased oil production, what is the value of increased electricity sales by leading in the loading order which is mandated to use the least polluting source. Then an analysis of cost verses benefit like any other business decision should be conducted.

SCAQMD Response

In step 4 of the top down approach to determining BACT under USEPA guidelines, a technology can be eliminated by source-specific environmental, energy, or economic impacts that demonstrate the technology is inappropriate as BACT. The HBEP combined-cycle power block is expected to generate 1.746 million tons of CO2 per year or 1.58 million metric tons per year. The HBEP simple-cycle power block will generate 207,151 tons of CO2 per year or 187,924 metric tons per year. The annual value of the HBEP CO2, based on the permitted operating levels and assuming the CO2 can be sold for $45 per metric ton for use in EOR (Refer to https://hub.globalccsinstitute.com/publications/global-technology-roadmap-ccs-industry-sectoral-assessment-co2-enhanced-oil-recovery-10) is approximately $89 million. This estimated cost-benefit assumes a carbon capture system is economically feasible such that the HBEP could be financed and constructed, the permitting of a CO2 pipeline to a nearby oil field could be achieved, the HBEP could operate at the permitted capacity factor, and a purchaser of CO2 for EOR could be identified. Since none of these factors can be relied on for this project, any value to AES would be uncertain. It also does not consider the fact that the expected capacity factor of the HBEP will diminish over time as more environmentally beneficial forms of electrical generation become available making the likelihood of consistent volumes of CO2 for sale remote at best. This will further exacerbate the cost impacts of deploying CCS on HBEP with the accompanying construction and operation of a CO2 transportation pipeline compared to any revenue potential from the sale of CO2 for EOR, which also is likely to decline over time.

As mentioned in the PDOC, although carbon control has been deemed infeasible for the HBEP, in response to a suggestion from EPA team members on other recent projects, the economic feasibility of CCS was still evaluated.

Comment 22

The PDOC states;

Based on the above analysis, thermal efficiency is the only technically and economically feasible alternative for CO2/GHG emissions control for the HBEP Project. AES has chosen to use both combined cycle as well as simple cycle turbine technology at the Huntington Beach plant. Although simple cycle turbines are not as efficient as combined cycle units, and therefore they emit more GHG pollutants per MW output, AES has chosen this configuration to meet the anticipated needs of the energy market they serve. The simple cycle units are capable of rapid start up and response to serve the peak load demand. The combined cycle units, although able to start relatively quickly, are not designed for this type of operation. The combined cycle units, in order to achieve superior thermal efficiency, must wait for the steam turbine to reach proper operating temperature. If the combined cycle units were to bypass the the steam turbine for the purposes of a quick start, they essentially become a simple cycle unit and therefore losses any advantage they have in thermal efficiency. Therefore, requiring AES to use only combined cycle units under the GHG BACT analysis would alter the applicant's purpose and objective of the proposed facility.

The district cannot just weave simple cycle back into the BACT analysis where no such exemption exists.

The circular logic that possibly not operating the steam turbine for occasional quick starts loses any advantage for combined cycle is beyond myopic, it is blind to the ongoing normal operational benefits of combined cycle and/or battery/condenser configurations.

SCAQMD Response
The HBEP Preliminary Determination of Compliance (PDOC) greenhouse gas (GHG) BACT analysis addressed AES's proposed installation of both simple- and combined-cycle gas turbines. The analysis considered the thermal efficiency of a combined-cycle configuration for HBEP's proposed simple-cycle gas turbines. It was determined that the combined-cycle gas turbines are not designed for peaking applications and that requiring combined-cycle gas turbines to be used in place of the HBEP's simple-cycle gas turbines did not result in an improvement of the HBEP's GHG efficiency. Furthermore, the analysis concluded that changing the project's design did not conform the project to the objectives (meeting the anticipated needs of the energy market AES serves) posed by AES. Therefore, the combined-cycle gas turbines did not represent BACT for the HBEP simple-cycle units. Substituting a battery in place of the simple cycle turbines limits the ability of the plant to provide sustained power generation. A turbine can provide power for as long as needed, while a battery storage system can only provide power until its capacity is depleted. Once depleted, the battery system needs time to recharge. The option of modifying the simple cycle turbines to include a clutch for synchronous condenser operation was considered by the CEC. It was determined that it was not advisable to fully analyze the option of a clutch now, since the project owner does not have a contract for peaker services nor the ancillary services provided by a synchronous condenser configuration.

Comment 23
The PDOC states;
Circuit Breakers
EPA in the Pio Pico Energy Center PSD permit requires the circuit breakers be equipped with a leak detection system, and be calibrated according to manufacturer specifications. EPA considers this to be BACT for circuit breakers. EPA further argues that the requirement is not redundant to the CARB regulation to reduce GHG (SF6) emissions from gas insulated switchgears, California Code of Regulations, Subchapter 10, Article 4, §95350-§95359.
A facility condition F52.2 will be added to enforce the BACT requirement for the circuit breakers, using the same language as the EPA permit.
The PDOC states;
In addition to the BACT requirement the PSD requirements generally include air quality modeling, ambient monitoring, and additional impact analysis. The modeling analysis shall demonstrate that there will be no violations of any NAAQS or PSD increments. However, because there are currently no NAAQS or PSD increments established for GHGs, the modeling analysis requirement would not apply for GHGs even if PSD is triggered for GHGs. EPA does not require monitoring for GHGs in accordance with Section 52.21(i)(5)(iii) and Section 51.166(i)(5)(iii), and EPA does not require impact analysis from GHGs in the nearby Class I areas. In addition, no offsets are required for CO because this pollutant is in attainment in the South Coast Air Basin.

The district erred in the belief that GHG impacts need not be modelled. The District should consider GHG domes and their pollutant trapping effects;
In the first study ever done on the local health effects of the domes of carbon dioxide that develop above cities, Stanford researcher Mark Jacobson found that the domes increase the local death rate. The result provides a scientific basis for regulating CO2 emissions at the local level
http://news.stanford.edu/news/2010/march/urban-carbon-domes-031610.html

SCAQMD Response
There are currently no regulatory requirements or guidelines for modeling GHG emissions from a point source for the purposes of permit evaluation. The article cited does not refer to CO2 emissions from a single source nor does it suggest any modeling protocol to analyze localized GHG impacts. EPA does not require any such localized health impacts modeling for GHGs.

Comment 24
The PDOC states;
It should be noted that, based on calculations shown in Appendix I, the simple cycle turbines would not meet the 1,000 lbs CO2/gross MW standard. Therefore, it is appropriate to limit the simple cycle turbines to a maximum annual net electric sales of 376.2 GW.
It is only appropriate to require combined cycle or other alternatives to simple cycle turbines Combined cycle represents part of BACT for a turbine.

SCAQMD Response
See response to Comment 6.

Comment 25
The PDOC states;
40 CFR Part 72 - (Acid Rain Provisions)
The facility will be subject to the requirements of the federal acid rain program, because the turbines are utility units greater than 25 MW. The acid rain program is similar to RECLAIM in that facilities are required to cover SO2 emissions with "SO2 allowances" that are similar in concept to RTCs. The Huntington Beach facility was given initial allowance allocations based on the past operation of their boilers. AES can either use those allocations, or if insufficient, must purchase additional allocations to cover the operation of the new turbines. The applicant is also required to monitor SO2 emissions through use of fuel gas meters and gas constituent analyses, or, if fired with pipeline quality natural gas, as in the case of the Huntington Beach facility, a default emission factor of 0.0006 lbs/mmbtu is allowed. SO2 mass emissions are to be recorded every hour. NOx and O2 must be monitored with Again the use of other gas sources must be considered.

SCAQMD Response
See response to Comment 4. AES has proposed only pipeline natural gas, and thus there is no reason to expect the use of any other fuel for the new turbines.

Comment 26

The PDOC should consider the effects of nitrogen deposition in the adjacent wetlands and other sensitive areas. It should also consider the effects of high temperature, high velocity, toxic thermal plumes on aircraft and their inhabitants and avian species.

SCAQMD Response

The projects impacts and background concentrations were compared to the secondary national ambient air quality standards with the reasoning that the standards were established to include protection against visibility impairment, and damage to animals, crops, vegetation, and buildings. Since the project emissions do not exceed the secondary NAAQS, it was concluded that there will be no significant impacts to soil and vegetation.

Potential plume impacts to aircraft were evaluated as part of the CEC's CEQA analysis (included in the Preliminary Staff Assessment). This is not within SCAQMD's jurisdiction.

Comment 27

This is a very densely populated residential area, with sea breezes that will blow air pollution from the plant inland to the severely impacted LA basin. Considering only populations within 6 miles of the plant is inadequate. This plant should have the best air pollution controls possible. A very good alternative to the plant would be a county program to put solar on every nearby roof.

The proposed desalination plant may be even worse than the power plant from an environmental point of view because of the harm it will do to the ocean, the amount of power that it will need, the possible control of water from public to private, and the precedent it creates.

SCAQMD Response

The impacts from HBEP to the surrounding area was modeled using a receptor grid of up to 20 km. Our analysis showed that the maximum impacts were adequately captured by this grid, therefore, SCAQMD staff did not find it necessary to increase the grid.

The HBEP will be constructed with what are currently considered the most effective controls available for reducing air pollution from natural gas fired turbines.

The commenter suggests use of roof top solar in lieu of this plant. If the CEC's analysis concludes this is a viable alternative in its FSA, SCAQMD will take that decision into consideration.

The Poseidon Desalination plant is not part of the project being reviewed by SCAQMD for the HBEP repower. The CEC's Final Staff Assessment (FSA) includes a review of the cumulative traffic and visual impacts from the desalination plant in conjunction with the proposed HBEP.

Responses to Comment Letter No. 3

1. VOC BACT for Combined Cycle Units

The PDOC proposes a 2ppm VOC limit as BACT for the HBEP. The 2ppm VOC limit is not BACT for VOC emissions. The applicant proposed and demonstrated in his BACT analysis in his previous application for the HBEP that a 1 ppm VOC limit is achievable on this class of combined cycle units and is being achieved on current natural gas fired power plants. The table below demonstrates that a VOC emission rate of 1.0 ppmvd (1-hour) is the lowest VOC emission rate demonstrated in practice or permitted for other facilities using good combustion practices and an oxidation catalyst. The Russell City Energy Center in the BAAQMD has achieved in practice a 1 PPM VOC limit. The PDOC must be revised as BACT for VOC for combined cycle units has been demonstrated in practice to be 1.0 ppmvd over 1 hour as shown in table 2-4 from the applicants BACT analysis conducted for the CEC

SCAQMD Response

There are a variety of different test methods used to quantify VOC emissions from combustion sources, including EPA Methods 18, 25, and 25A, and CARB Method 100. In the South Coast, the preferred method for gas turbine testing is a modified Method 25.3 for these sources for verification of compliance with VOC BACT. This method is considered exceptionally comprehensive for determining VOC emissions from combustion sources and is designed to minimize condensation issues that may be associated with other test methods.

The SCAQMD has determined that VOC BACT for combined- and simple-cycle turbines is 2.0 ppm at 15% O2, 1-hour average, based on District Method 25.3/modified Method 25.3. The commenter asserts that Russell City Energy Center has achieved in practice a limit of 1 ppm VOC averaged over 1 hour and this represents achieved in practice BACT for combined-cycle turbines. In comment no. 4 below regarding simple-cycle turbines, the commenter similarly asserts that the Marsh Landing and the Mariposa turbines are permitted with a 1 ppm VOC limit, and this limit has been achieved in practice for Marsh Landing. All three facilities are in the Bay Area Air Quality Management District (BAAQMD).

In the Huntington Beach Energy Project (HBEP) PDOC, condition D29.5 specifies source testing requirements for the combined- and simple-cycle turbines for the initial source test, and condition D29.7 specifies source testing requirements for the subsequent periodic source tests that are required to be conducted at least once every three years.

For the PDOC, both permit conditions specify the required source test method for VOC emissions is District Method 25.3. These conditions also state: "For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined SCAQMD may be the following:…." The three-step procedure that follows describes the **modified** Method 25.3, which lists additional requirements to provide improved accuracy at the lower end of the range that were developed by the SCAQMD Source Test Engineering Department.

In response to your comments, both permit conditions will be updated for the FDOC. At the time the permit conditions were developed, the SCAQMD was in the process of transitioning from either using unmodified Method 25.3 or modified Method 25.3 with Method TO-12 analysis for sampling. Source test companies no longer use these two alternatives because, since then, both alternatives have been determined through experience to be not as reliable as modified Method 25.3 (without the use of Method TO-12), as discussed below. These conditions will be revised to require the use of modified Method 25.3 without the alternative of using the outdated TO-12 option for analysis of Summa canisters.

Further, in response to your comments on combined- and simple-cycle turbines, SCAQMD contacted the BAAQMD for BACT and source testing information on Russell City Energy Center, Marsh Landing and Mariposa. BAAQMD indicated BACT is 1 ppm POC at 15% O2, averaged over a 1-hour period, for combined- and simple-cycle turbines. (POC means precursor organic compound and is equivalent to VOC.) Unlike SCAQMD permits, the BAAQMD permits do not provide permit conditions to specify source test methods and do not require a source test protocol to be submitted and approved prior to performing a source test. As requested, BAAQMD provided a description of the source testing method from recent source test reports for Russell City and Mariposa. (BAAQMD indicated Marsh Landing used the same source testing company as Mariposa and likely the same source testing method.)

SCAQMD Source Testing Engineering Department compared the source test methods used for Russel City and Mariposa with modified District Method 25.3 used by the SCAQMD for turbine testing. The Source Test Engineering Department's comments are summarized as follows:

- For both Russell City and Mariposa, the sampling and analysis were performed using Method TO-12—Method for the Determination of Non-Methane Organic Compounds (NMOC) in Ambient Air Using Cryogenic Preconcentration and Direct Flame Ionization Detection (PDFID). The SCAQMD had learned that because Method TO-12 is an ambient concentration method, laboratories were variously modifying the method to one for stack sampling to compensate for the methane and ethane interferences and the higher concentrations in the stack samples. Methane and ethane, defined as non-VOC compounds, are required to be separated from the VOC compounds in the sample. The test results from TO-12 were inconsistent and it is unclear as to what the methods, modified in various ways by each laboratory, were actually measuring. In response to such situations, SCAQMD has developed modified Method 25.3--Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions from Clean Fueled Combustion Sources to accurately sample and analyze stack exhaust from turbines. For example, TO-12 uses cryogenic preconcentration to try to physically freeze out methane and ethane from the stack sample by adjusting the temperature of the gaseous sample. Since the separation is not precise, if some of the methane and ethane is left in the sample, then the analyzed VOC concentration of the sample is erroneously high. On the other hand, if some of the VOC is removed along with the methane and ethane, then the analyzed VOC concentration is erroneously low. Modified Method 25.3 uses gas chromatography to precisely analyze a gas sample for VOC because gas chromatography provides separate peaks for methane, ethane, and VOC compounds. Based on source test reports received for SCAQMD facilities, source testing companies have been analyzing Summa canisters using the canister analysis portion of AQMD Method 25.3 exclusively based on their experience that it results in more consistent results than the unmodified EPA Method TO-12.

- For Russell City, stack samples were collected in specially-prepared stainless steel (SUMMA) canisters with the internal vacuum kept above 5 inches of mercury (same as 127 mm of mercury) during sampling. This procedure was formerly used by the SCAQMD as modified Method 25.3. In the current version of modified Method 25.3, conditions D29.2 and D29.3 now require the stack samples to be extracted directly into Summa canisters, while maintaining a final canister pressure between 400-500 mm of mercury absolute to minimize condensation issues. The partial vacuum in the canister serves to minimize the amount of water-soluble VOC that is condensed out with the water in the canister and lost from the gaseous portion of the sample. If part of the VOC is condensed out, the gaseous portion that remains and is analyzed will result in erroneously low VOC concentration results (low-bias test results).

- For Mariposa, stack samples were collected into nitrogen purged Tedlar sample bags instead of Summa canisters. The Tedlar bag sampling is from EPA Method 18, which differs from the SCAQMD sampling methods in that a partial vacuum is not created in the sample bag. Without a partial vacuum, the water-soluble VOC condenses out and the analysis of the remaining gaseous portion results in erroneously low VOC concentration results.

- Therefore, the sampling methods for Russell City and Mariposa were different from the sampling method in modified Method 25.3 for SCAQMD. In addition, the sampling methods for Russell City and Mariposa were different from each other.

The SCAQMD is using a different sampling method and analysis than Russell City and Mariposa. The modified Method 25.3 yields consistent results to support the BACT standard of 2 ppmvd VOC at 15% O2, 1-hour averaging. The sampling and analysis methods used for Russell City and Mariposa are from various prior versions of sampling and analysis methods used by the SCAQMD. The measured VOC results from the SCAQMD's modified Method 25.3 are likely to be different from the measured VOC results from BAAQMD. Due to the potential erroneously low readings from methods used by other agencies, the SCAQMD uses modified District Method 25.3. The 2 ppmvd VOC is the lowest achievable as measured by any method.

In footnote 2 on page 2, the commenter asserts that CEC staff is proposing some changes to the SCAQMD conditions to allow for alternative test methods if there is concurrence with the U.S. EPA, ARB and SCAQMD. Both CEC and SCAQMD conditions include: "For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, CARB, and SCAQMD." The inclusion of this provision allows for future refinement of the source test method for VOC and other pollutants, as appropriate.

Please see response to comment no. 4 "BACT for CO for Combined Cycle Units" in which the SCAQMD provides a BACT determination evaluation for the CO and VOC emissions limits for Warren County Power Station, Virginia.

2. <u>BACT for PM-10/2.5 for Combined Cycle Units</u>

The PDOC allows the facility to emit up to 8.5 pounds per hour per turbine for particulate matter emissions. The PDOC claims to utilize the Oakley Project and mentions the Russell City Energy Center in their BACT analysis. Both projects have lower PM 2.5 emission rates than required by the HBEP PDOC. First the Russell City Energy Center has a lower particulate matter limit of 7.5 pounds per hour as approved by the CEC in AQ 19 (h) on August 11,2010 Approval of the Petition to Amend. According to compliance documents submitted to the Commission Russell City Energy Center has remained in compliance with this condition.

The Oakley Project which was examined in the BACT analysis utilizes the exact same equipment as proposed for the HBEP combined cycle project. The Oakley Project contains a particulate matter limit of 7.4 pounds per hour. BACT for the HBEP combined cycle train is 7.5 pounds per hour as achieved by the Russell City Energy Center.

<u>*SCAQMD Response*</u>

SCAQMD Rule 1302(h) defines New Source Review (NSR) BACT as follows:

> BEST AVAILABLE CONTROL TECHNOLOGY (BACT) means the most stringent emission limitation or control technique which:
>
> (1) has been achieved in practice [AIP] for such category or class of source; or
>
> (2) is contained in any state implementation plan (SIP) approved by the US EPA approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or
>
> (3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.

SCAQMD has a separate definition for Prevention of Significant Deterioration (PSD) BACT. SCAQMD Rule 1702(e) defines PSD BACT, in part, as follows:

> Best Available Control Technology (BACT) means the most stringent emission limitation or control technique which:
>
> (1) has been achieved in practice for such permit unit category or class of source. For permit units not located at a major stationary source, a specific limitation or control technique shall not apply if the owner or operator of the proposed sources demonstrates to the satisfaction of the Executive Officer that such limitation or control technique is not attainable for that permit unit; or
>
> (2) is contained in any State Implementation Plan (SIP) approved by the Environmental Protection Agency (EPA) for such permit unit category or class of source.
> A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer that such limitation or control technique is not presently achievable; or
>
> (3) is any other emission control technique, including process and equipment changes of basic and control equipment, found by the Executive Officer to be technologically feasible and cost-effective for such class or category of sources or for a specific source…

For the HBEP project, PM_{10} is subject to NSR BACT applicable to non-attainment areas and PSD BACT applicable to attainment areas, because PM_{10} is not in attainment with the California 24-hr and annual standards but is in attainment with the federal 24-hr standard. **As set forth above, SCAQMD Rules 1302(h) and 1702(e) define NSR BACT and PSD BACT, respectively, in terms of the most**

stringent emission limitation <u>or</u> control technique, and do not require both types of BACT limits. NSR BACT is determined to be PUC quality natural gas with sulfur content ≤ 1 grain/100 scf for combined-cycle turbines and simple-cycle turbines, respectively. PSD BACT is determined by the top-down analysis to be pipeline-quality natural gas with low sulfur content, good combustion practice, and inlet air filtration for both combined-cycle and simple-cycle turbines. The PDOC does not claim to utilize the Oakley Project and did not mention the Russel City Energy Center in the BACT analysis for particulate matter.

The top-down analysis identifies pipeline-quality natural gas with low sulfur content, good combustion practice and inlet air filtration as available combustion control technology/technique, and electrostatic precipitators and baghouses as available add-on control equipment. The analysis explains that electrostatic precipitators and baghouses are typically used to control sources with high particulate matter emission concentrations. Neither of these add-on control technologies is appropriate for use on natural-gas-fired turbines because of the very low levels and small aerodynamic diameter of particulate matter from natural gas combustion. Therefore, electrostatic precipitators and baghouses were not considered technically feasible add-on control equipment. Therefore the only remaining feasible control technologies/techniques are pipeline-quality natural gas with low sulfur content, good combustion practice and inlet air filtration. This determination is in accord with the Clean Fuels Policy adopted by the SCAQMD Governing Board, in January 1988, that included a requirement to use clean fuels as part of BACT/LAER. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for NOx, SOx, VOC, and PM_{10}.

The SCAQMD has not imposed a numerical emissions limit in addition to requiring the control technologies/techniques of pipeline-quality natural gas with low sulfur content, good combustion practice and inlet air filtration because there are no feasible add-on controls. Particulate matter is unlike such pollutants as NOx and CO where the add-on control equipment (SCR and CO catalyst, respectively) can be designed to achieve the required emissions limit with proper operation. The specification of an emission limit for design and the proper operation of the control system are within the control of the operator. Particulate emission rates are subject to variability depending on the instantaneous sulfur content of the fuel, turbine operating parameters, and amount of particulate matter in the ambient air, which are factors generally not within the control of the operator.

The commenter asserts that the 8.5 lb/hr PM_{10} BACT limit for HBEP should be lowered to 7.5 lb/hr as achieved by the Russell City Energy Center. The 8.5 lb/hr PM_{10} limit is NOT a BACT limit. As discussed in the PDOC, the purpose of the limit is for determining offsets and air quality impacts. Our review of the permit conditions and source test results for Russell City tentatively confirm the facility is meeting the 7.5 lb/hr limit. The Russel City combined-cycle turbines are Siemens/Westinghouse 501F, rated at 2,038.6 MMBtu/hr maximum rated capacity, located in the City of Hayward, Northern California. The HBEP combined-cycle turbines are General Electric, Model 7FA.05, 2275 MMBTU/HR HHV, located in Huntington Beach, Southern California. As with the HBEP turbines, the Russel City turbines are not equipped with add-on control. The turbines at Russell City and HBEP are non-identical models with non-identical ratings and located in different geographic locations. These factors may result in different PM_{10} emission rates. For example, assuming the concentration of PM_{10} in the exhaust flow is the same for the HBEP and Russell City turbines, the higher rating for the HBEP turbines will result in higher exhaust flow and thus higher PM_{10} emissions in pounds per hour. Measured PM_{10} emissions may vary even on identical turbine models with identical ratings in the same or different geographic locations, and may vary on non-identical turbine models with non-identical ratings in the same or different geographic locations, due to these factors, as well as the selection and implementation of test methods by the source testing company.

The commenter further asserts the Oakley Generating Station (OGS) contains a particulate matter limit of 7.4 lb/hr. The OGS project is on hold before construction. Our review of the BAAQMD Evaluation for Renewal of the Authority to Construct (ATC) for the Oakley Generating Station Plant Number 19771, dated August 2013, indicates the ATC does not contain a permit condition that limits the hourly PM_{10} emissions. Condition no. 10 specifies the owner/operator shall fire the Gas Turbines (S-1 and S-2) exclusively on PUC regulated natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. The stated basis for this condition is BACT for SO_2 and PM_{10}. Condition no. 43 specifies a facility-wide PM_{10} limit for the operation of the two turbines, auxiliary boiler, and fire pump. The stated basis is “cumulative increase,” not BACT. Cumulative increase is used for determining the offsets required. Similarly, the HBEP PDOC sets a limit of 8.5 pounds per hour per turbine for particulate matter emissions for the purpose of determining offsets and air quality impacts, not as BACT.

The commenter states that the limit for Russell City Energy Center was thoroughly litigated at the USEPA’s Environmental Appeals Board (EAB)[2]. In that case, the EAB issued a partial remand of the EPA’s Region 9 PSD air permit for the Pio Pico Energy Center, not the Russell City Energy Center, with regard to the particulate emission limit determined as BACT. The relevant part of the remand required Region 9 to consider emission data and BACT limits from Panoche and CPV Sentinel in its BACT analysis and document whether the limits or emission rates observed at these facilities can or cannot be achieved at Pio Pico.

The EAB case discussed BACT in terms of emission limitation pursuant to the definition of federal BACT for the PSD program. CAA §169(3) and 42 U.S.C. §7479(3) define federal BACT, in part, 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….

CAA §171(3) and 42 U.S.C. §7501(3) define federal LAER, in part, for the NSR program as follows:

> The term "lowest achievable emission rate" means for any source, that rate of emissions which reflects—

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2 https://yosemite.epa.gov/oa/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/A73AC96F4C0E14CE85257BBB006800F2/$File/Pio%20Pico...36.pdf

(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent….

Both federal PSD BACT and LAER are imposed in terms of **emission limitations**. The CAPCOA BACT Clearinghouse Resource Manual: **Information on Control Technology and Air Permitting Processes in California**[3]**, dated June 21, 2000, discusses f**ederal versus California control technology requirements. On page 1 of Chapter VII, the manual explains that California Health and Safety Code Section 42300 authorizes delegation of stationary source permitting authority from the state to local air pollution control districts. Further, each district has its own set of definitions and rules, which can vary by district. Some districts used BACT and LAER definitions out of the federal Clean Air Act, discussed above. However, most districts have adopted PSD and NSR control technology requirements that are different from the federal definitions of control technology requirements. As discussed above, HBEPSCAQMD Rules 1302(h) and 1702(3) require an **emission limitation <u>or</u> a control technique**.

The 8.5 lb/hour limit for the combined-cycle turbines is an estimate of the maximum PM_{10} emissions level that would result from using low-sulfur natural gas and provides the basis for offset requirements. The total PM_{10} is comprised of the PM_{10} in the turbine exhaust (6.7 lb/hr as guaranteed by Nooter/Eriksen for the HBEP) and the ammonium sulfate particulates formed in the selective catalytic reduction system (SCR). A percentage of the SO_2 in the turbine exhaust is assumed to oxidize to SO_3 in the CO catalyst and SCR, and the SO_3 reacts with ammonia in the SCR to form ammonium sulfate particulates. With the addition of the conservatively calculated ammonium sulfates particulates, the 8.5 lb/hr emission rate is considered to be conservative and the actual emissions are likely to be less. In order to ensure sufficient offsets are provided, the assumed emissions rate needs to be conservative, that is, potentially higher than actual emissions.

3. It is particularly important that BACT for PM 2.5 be as stringent as possible as the SCAQMD has recently been classified as serious non-attainment for PM 2.5. The modeling analysis reviewed by staff including the turbines proposed for the project concluded that the project would exceed SCAQMD PM 10 and PM 2.5 thresholds that are recommended for general CEQA use. The district modeling staff concluded that the PM 2.5 and PM 10 threshold exceedances were not significant since ERC's are to be provided. The ERC's provided are for the PM-10 emissions and are from the SCAQMD internal bank. The PM-10 credits form SCAQMD's internal bank do not mitigate local impacts from PM 2.5 sources.

SCAQMD Rule 1304 (a) (2) provides an exemption from the modeling requirement of Rule 1303 (b) (1) for the installation of new turbines since AES is allegedly permanently retiring their electric stem utility boilers. The SCAQMD PM10 and PM2.5 localized CEQA thresholds are only applied to the auxiliary boiler portion of the project. This leads the CEC and the district to conclude that the exceedance of the SCAQMD PM 10 and PM 2.5 thresholds are not significant. The PDOC concludes

[3] https://www.arb.ca.gov/bact/docs/fedvscal.htm

that the PM 2.5 emissions credits are not required since PM 2.5 emissions and their precursors are less than 100 tpy. The PDOC does require the applicant to mitigate PM-10 emissions for SCAQMD internal bank. But there is no mitigation for the 24 hour PM 2.5 CEQA significant impact.

SCAQMD Response

The CEC is the CEQA lead agency for the HBEP and SCAQMD is a CEQA responsible agency. As noted in the modeling review memo (dated May 18, 2016), SCAQMD modelling staff reviewed the analysis in the CEC's CEQA document and noted that the project would exceed the SCAQMD's localized significance thresholds modeled concentration (the result of the modelling showed an expected concentration of 4.7 ug/m3, 24 hour average, while the significance threshold is 2.5 ug/m3, 24 hour average). Also, , but that the impacted area is in an unoccupied area adjacent to the project site. As a commenting agency, SCAQMD staff notes that regional emission offsets should not be used as mitigation for a localized impact. However, as the turbine portion of this project is exempt from analyzing PM10 and PM2.5 localized impacts pursuant to SCAQMD Regulation XIII, the SCAQMD PM10 localized CEQA thresholds for general use should only be applied to the boiler portion of the project. The boiler on its own does not exceed SCAQMD PM10 and PM2.5 localized CEQA thresholds.

SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects, with the offsets provided from the SCAQMD internal offset accounts. These internal account offsets will cover all emissions increases of PM10. Offsets for PM2.5 as distinct from PM10 are not required as PM2.5 emissions are less than the applicability threshold of Rule 1325, which is distinct for PM2.5. On page 183 of the HBEP PDOC, Rule 1304.1(a) and (c)(1) state that the applicant is required to pay fees for the offsets provided by the SCAQMD.

4. BACT for CO for Combined Cycle Units

The PDOC proposes a 2ppm limit for CO emissions. A 2ppm CO limit is not BACT for CO emissions. Kleen Energy Systems was able to successfully demonstrate compliance with the CO emission limits of 0.9 and 1.5 ppmvd for unfired and fired operation, respectively.[4] This is the appropriate BACT limit for the HBEP not 2 ppm averaged over 1 hour. The Palmdale Hybrid project has a 1.5 ppm CO limit in its PSD permit.[5] Virginia Electric and Power Company's Warren County Facility has permitted limits of 1.2 and 1.3 ppmvd at 15% O2.

SCAQMD Response

There are four projects with lower CO emissions than 2.0 ppmvd at 15% O2. These projects are Kleen Energy Systems, Warren County Power Station, Avenal Energy Project (not included in your comment), and Palmdale Energy Project (Some of the limits on the facility permits for these projects differ from the limits indicated in your comment.)

- Kleen Energy Systems, Connecticut
  This facility currently has the lowest permit limits for CO. The permit includes CO limits of 0.9 ppm and 1.8 ppm, on a 1-hr averaging basis for operating without and with duct burner,

[4] http://www.energy.ca.gov/sitingcases/huntington_beach_energy/documents/applicant/AFC/Volume%202%20Appendices/HBEP_Appendix%205.1D_BACT%20Determination.pdf Page 2-8

[5] After 3 year demonstration period.

respectively. The initial source tests were performed 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 and 1.7 ppmvd for unfired and fired operation, respectively.

It should be emphasized that the Kleen Energy Systems permit provides an exemption from these limits during periods of "shifts between loads." Further, the permit does not specify limits for those periods of shifts between loads, which realistically can comprise a substantial percentage of normal operations. In contrast, the SCAQMD does require BACT during periods of shifts between loads. The Kleen Energy System limits do not meet the definition of BACT as implemented by the SCAQMD for a facility with these operating characteristics."

Update: There are no updates. It should be noted that the limits do not apply to operation at below 60% load. In contrast, the SCAQMD does require BACT during periods of shifts between loads and operation at below 60% load. As the HBEP turbines are equipped with fast start and ramp-up/ramp-down capabilities, load changes are expected to be a regular occurrence. As the minimum turndown for the turbines is 44% load, operation at below 60% load is expected to be a regular occurrence. The permit limits for Kleen Energy are not achieved in practice for facilities where BACT must be met during shifts between loads and at below 60% load.

- Palmdale Energy Project (formerly Palmdale Hybrid Power Project), California
  The final PSD permit specifies CO emission limits of 1.5 ppm and 2.0 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively, after a 3-year demonstration period during which the CO emissions limit is 2.0 ppm for operating without and with duct burner. This facility was not constructed.

  The CEC website indicates a Petition to Amend was filed on 7/27/15, and the Amendment Preliminary Staff Assessment was released on 3/23/16 for the revised project, now renamed the Palmdale Energy Project. Pg. 4.1-26 of the PSA indicates CO emission concentrations would be limited to 2.0 ppmvd, which is the same as proposed for the HBEP combined-cycle turbines."

  Update: The FSA was published on 9/12/16. The limits have not changed from the PDOC.

- Warren County Power Station, Virginia
  The final PSD permit includes CO emission limits of 1.5 ppm and 2.4 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively. The 1.5 ppm without duct burner is lower than the SCAQMD BACT/LAER limit of 2.0 ppm, but the 2.4 ppm with duct burner is higher than the SCAQMD BACT/LAER limit of 2.0 ppm. Based on publicly available information, commercial operation started in December 2014."

  Update: Following the issuance of the HBEP PDOC, the SCAQMD contacted the Virginia Department of Environmental Quality (DEQ) regarding Warren County Power Station. The most recent amended PSD permit, dated 10/24/13, had not revised the CO and VOC limits for operating without and with duct burner. The engineering evaluation indicated the limits had been proposed by the applicant. For CO, the limits remain 1.5 ppmv without duct burner firing and 2.4 ppmv with duct burner firing. For VOC, the limits remain 0.7 ppmvd without duct burner firing and 1.6

ppmvd with duct burner firing. A BACT determination evaluation for the VOC limits is provided here to supplement the response to comment no. 1 "VOC BACT for Combined Cycle Units."

The only source tests on the three turbines were performed in December 2014.
The SCAQMD Source Test Engineering Dept. was requested to provide a formal evaluation of the source test protocol (88 pages) and source test report for Turbine 1A (963 pages) for the source test performed on 12/5 – 12/7/2014. The evaluation was to determine whether the data quality met the standards of the SCAQMD.

The following comments and conclusions are from the SCAQMD Source Test Engineering evaluation for the Warren County protocol and source test report.

- <u>VOC</u>
  - The VOC testing and analyses were performed according to EPA Method 25A. EPA Method 25A is not a suitable method to measure VOC at the emission limits set forth in the Virginia PSD permit because EPA Method 25A cannot detect oxygenated hydrocarbons such as formaldehyde, and VOC concentrations less than 2 ppm are in the statistical noise of EPA Method 25A.
  - Previous parallel testing on similar gas-fired sourced in the SCAQMD using SCAQMD Method 25.3 have shown results higher than those given by EPA Method 25A. The higher results given by SCAQMD Method 25.3 are most likely due to the ability of Method 25.3 to detect oxygenated hydrocarbons (an ability that EPA Method 25A does not have) and the actual presence of such hydrocarbons in low concentrations from natural gas-fired turbines. Because of the higher results given by SCAQMD Method 25.3, it is doubtful that any gas turbines could meet the VOC emission limits in the Virginia permit using SCAQMD Method 25.3 to measure VOC. It should be noted that the likely concentrations of oxygenated hydrocarbons will likely cause exceedance of the Virginia permit limits.
  - Most of the VOC data points in the report were zero or less. This "negative drifting" of the data is evidence of the presence of oxygenated hydrocarbons. The oxygenated hydrocarbons cause destructive interference with flame ionization detector (FID) methods, i.e., the oxygenated hydrocarbons subtract from the VOC readings. EPA Method 25A is an FID method.
  - In order to accurately show compliance with the VOC limits in the Virginia permit, a method that can measure oxygenated hydrocarbons at low concentrations as SCAQMD Method 25.3 must be used. Methods that cannot measure oxygenated hydrocarbons at low concentrations such as EPA Method 25A must not be used or allowed.
  - Section 4.2 of the test report states that the sample gas was sent through a condenser in order to dry the sample gas. This would further cause a low bias to the EPA Method 25A VOC data, meaning that some of the VOC is condensed out and lost from the gaseous portion of the sample that is analyzed.
  - Some of the reported gaseous emissions from EPA Method 25A cannot be reliably verified or they were performed incorrectly. Since no parallel VOC testing using a method that is suitable for the VOC concentration limits was conducted during the test runs that could possibly confirm or deny the EPA Method 25A data, the reported VOC

concentration data should not be used for any purpose, including setting BACT standards, compliance purposes and emissions calculations.

- For these reasons, the SCAQMD will not be adopting as VOC BACT the limits of 0.7 ppmvd without duct burner firing and 1.6 ppmvd with duct burner firing found in the Warren County Power Station PSD permit. VOC BACT will remain 2 ppmvd at 15% O_2, without and with duct burner firing.

- CO
  - Some of the reported gaseous emissions fell short of established analytical standards, and the reported emissions have been recalculated upward to default levels for qualitative compliance determination only. This applies to reported CO concentrations. SCAQMD regards the valid reporting range of measurement of a EPA Method 10 analyzer as being 20-95% of the instrument full-scale-range (FSR). Gas measurements (as measured at the stack) falling below this lower limit are adjusted upward to the 20% FSR value for gas concentration Rule/Permit Compliance limit determination only, and adjusted CO values cannot be used quantitatively for mass emission or emission factor calculations because they are probably overstated.

  - The adjusted CO values, summarized in the table below, indicate the turbines without duct burner operation meet the 1.5 ppm CO @ 15% limit.

Unit/Condition	Source Test Report Results (ppm @ 15% O_2)	Adjusted Concentration (ppm @ 15% O_2)	Permit Limits (ppm @ 15% O_2)
Unit 1A w/o duct burning	0.0	< 0.8	1.5
Unit 1 A with duct burning	0.0	< 0.6	2.4
Unit 1B w/o duct burning	0.0	< 1.5	1.5
Unit 1B with duct burning	0.0	< 1.3	2.4
Unit 1C w/o duct burning	0.29	< 1.5	1.5
Unit 1C with duct burning	0.00	< 1.3	2.4

As indicated in the PDOC, achieved-in-practice LAER is based on a minimum of 183 cumulative operating days (6 months). Warren County Generating Station started commercial operation in December 2014, and the only source tests performed were completed that month. The Virginia DEQ has confirmed that each turbine has operated a minimum of 6 months without the duct burner since December 2014. The SCAQMD has obtained and reviewed validation data, including CO CEMS data for CO for the two years of operation which includes operation without the duct burner and with the duct burner, for the three turbines. The SCAQMD has made a BACT determination that CO BACT for combined-cycle turbines is 1.5 ppmvd at 15% O_2.

Upon SCAQMD's request, AES is in the process of securing a written performance guarantee from the equipment vendor to ensure the proposed simple-cycle turbines with oxidation catalyst will comply with the new BACT standard of 1.5 ppmvd CO at 15% O_2 without duct burner.

5. BACT for VOC for LMS-100 PB Units

The PDOC proposes BACT for VOC's of 2 ppm averaged over 1 hour. The BAAQMD determined that the simple cycle Marsh Landing gas turbines would be able to meet a POC emissions limit corresponding to 1 ppmvd @ 15% O2 averaged over one hour. The simple-cycle Marsh Landing gas turbines were limited to 2.9 lb/hour or 0.00132 lb/MMBtu in the permit conditions; these values correspond to 1 ppmvd @ 15% O2. These limits have been achieved in practice.

Also the BAAQMD in the Mariposa FDOC, "determined that BACT for the simple-cycle gas turbines for POC is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMbtu, which is equivalent to 1 ppm POC, 1-hr average." BACT for VOC's for the HBEP LMS-100 PB turbines is 1 ppm averaged over 1 hour.

SCAQMD Response

The response to comment no. 1 "VOC BACT for Combined Cycle Units," above, addresses both the combined- and simple-cycle turbines.

6. BACT for CO for LMS-100 PB Units

The Applicant has proposed a CO emission limit of 4 ppmvd at 15% O2 averaged over each hour. The BAAQMD imposed on the Mariposa Power Plant a CO BACT limit of 2.0 ppm, which is more stringent than the 4 ppm CO limit proposed for the ACECP. The BAAQMD also imposed a 2 ppm CO limit for the Marsh Landing Project. These limits have been achieved in practice and must be considered as BACT under district regulations.

SCAQMD Response

In response to your comment, SCAQMD contacted the BAAQMD for information on Mariposa Energy facility and the Marsh Landing Generating Station that is required to perform a CO BACT determination for simple-cycle turbines. SCAQMD determined that Mariposa Energy is limited to 2 ppmvd at 15% O_2, averaged over any rolling 3-hour period, and source testing since 2014 has demonstrated compliance with that limit. Marsh Landing is limited to 2 ppmvd at 15% O_2, averaged over any 1-hour period. The facility went on-line in the second half of 2013 and has demonstrated compliance with that limit. Therefore, the 2.0 ppmvd at 15% O_2 emission level has been verifiably achieved in practice.

As a result, the SCAQMD agrees with the commenter. BACT for CO for simple-cycle turbines will be revised from 4 ppmvd to 2 ppmvd, both at 15% O_2, averaged over a 1-hour period for the HBEP. The 1-hour averaging period for Marsh Landing was selected over the rolling 3-hour averaging period for Mariposa Energy, because it is more stringent and because SCAQMD typically bases BACT on a 1-hour averaging period.

Upon SCAQMD's request, AES has secured a written performance guarantee from BASF, the oxidation catalyst manufacturer, to ensure the proposed simple-cycle turbines with oxidation catalyst will comply with the new BACT standard of 2.0 ppmvd at 15% O2.

7. BACT PM-10/PM 2.5 for LMS-100 PB Units.

The FDOC proposes a 6.24 pound per hour per turbine PM-10 limit for the HBEP. BACT for the LMS-100 turbines was recently litigated at the EAB and found to be 5.5 pounds per hour for the

Pio Pico Project. The applicant for the Carlsbad Energy Center proposed a 3.5 pound per hour rate for the LMS-100 turbine. The CEC ultimately determine that PM 2.5 BACT for the LMS -100 units in Carlsbad was 5 pounds per hour in condition AQ-35. The PDOC frankly admits that the vendor guarantees a 5 pound per hour emissions limit. BACT for PM 2.5 emissions for this project is 5 pounds per hour.

SCAQMD Response
The response to comment no. 2 "BACT for PM-10/2.5 for Combined Cycle Units," above, addresses combined- and simple-cycle turbines. The SCAQMD has determined NSR BACT and PSD BACT to be the control technique of using pipeline-quality natural gas with low sulfur content, good combustion practice, and inlet air filtration.

The 6.23 lb/hour limit for the simple-cycle turbines is an estimate of the maximum PM_{10} emissions level that would result from using low-sulfur natural gas and provides the basis for offset requirements. The total PM_{10} is comprised of the PM_{10} in the turbine exhaust (5 lb/hr as guaranteed by General Electric for the HBEP) and the ammonium sulfate particulates formed in the selective catalytic reduction system (SCR). With the addition of the conservatively calculated ammonium sulfates particulates, the 6.23 lb/hr emission rate is considered to be conservative and the actual emissions are likely to be less.

8. PM 2.5 modeled exceedances are not mitigated

The modeling analysis reviewed by staff including the turbines proposed for the project concluded that the project would exceed SCAQMD PM 10 and PM 2.5 thresholds that are recommended for general CEQA use. The district modeling staff concluded that the PM 2.5 and PM 10 threshold exceedances were not significant since ERC's are to be provided. The ERC's provided are PM-10 emission credits and are from the SCAQMD internal bank. The PDOC does not require offsets for PM 2.5. There is no identified mitigation for the PM 2.5 exceedances.

SCAQMD Rule 1304 (a) (2) provides an exemption from the modeling requirement of Rule 1303 (b) (1) for the installation of new turbines since AES is allegedly permanently retiring their electric stem utility boilers. The SCAQMD PM10 and PM2.5 localized CEQA thresholds for general use are only applied to the auxiliary boiler portion of the project. This leads the CEC and the district to conclude contrary to district regulations that the exceedance of the SCAQMD PM 10 and PM 2.5 thresholds that are recommended for general CEQA use are not significant. The PDOC concludes that the PM 2.5 emissions credits are not required since PM 2.5 emissions and their precursors are less than 100 tpy. The PDOC does require the applicant to mitigate PM-10 emissions for SCAQMD internal bank. But there is no mitigation for the 24 hour PM 2.5 CEQA significant impact which violates district policy.

SCAQMD Response
See response to Comment no. 3

9. Rule 1303

The PDOC states that, "The facility has also submitted a statement certifying that all facilities owned and operated in the state are currently in compliance with all applicable air quality regulations, as required by Rule 1303. AES is also the owner of the Redondo Beach Power Plant. According to the EPA Compliance and Enforcement website (ECHO) the Redondo Beach Facility is a high priority violator and the facility has been out of compliance with its air quality regulations for 12 quarters in a row.

SCAQMD Response
The EPA Compliance and Enforcement website (ECHO)[6] does indicate the AES Redondo Beach facility is a high priority violator and the facility has been out of compliance with its air quality regulations for 12 quarters. On 10/3/2014, the commenter included the same comment in a document entitled "Helping Hand Tools- Comments: Comments on the PMPD and FDOC on Behalf of Helping Hand Tools" posted on the CEC website for the original Huntington Beach Energy Project[7]. On page 9, the comment states, in part: "AES owns and operates the Redondo Beach Project which has been a High Priority Violator of the clean air act for the last twelve quarters in a row according to the EPA. Accordingly the air permit cannot be issued until the Redondo Beach facility comes into compliance with SCAQMD Rule 1303."

Since the comment period for the FDOC had already passed, the CEC responded to the comment on the PMPD, with input from the SCAQMD, in a document, entitled "Energy Commission Staff's Response and Comments to the Revised Presiding Member's Proposed Decision and Response to Comments"[8] posted on the CEC website. On pages 10-11, the CEC Staff Response states, in part: "Tools cites the information from EPA's ECHO website. However, that information is incorrect. Staff has checked with EPA Region 9 and SCAQMD's enforcement personnel regarding the compliance status of AES Redondo Beach facility. Both agencies confirm that the Redondo Beach facility is currently in compliance with all permit requirements and no violations are currently open. All the previous violation cases have been addressed and closed, although the ECHO website is not up to date. Therefore, AES is in compliance with Rule 1303 b (5) B requirements, and the issuance of a permit for HBEP permit would not be affected by any potential violations at Redondo Beach or any other AES facility." The CEC's response remains valid.

At that time, CEC staff confirmed with the EPA that the violations were all coming from the SCAQMD database. SCAQMD Title V Administration staff confirmed that the ECHO system does not correctly reflect the compliance status recorded in SCAQMD's database. ECHO updates its information only once a year and the information has been updated since 2014, but counts violations on a quarterly basis. Also, EPA defines a facility as being non-compliant until a District prosecutor assesses a penalty and closes the case, which can be substantially later than when the facility actually comes into compliance.

The SCAQMD website is a better resource because it provides up-to-date compliance status, including for Notices of Violation and Notices to Comply. The Facility Information Detail (FIND) web page can be accessed at http://www3.aqmd.gov/webappl/fim/prog/search.aspx. If you enter the SCAQMD facility ID and select the Compliance tab, you will be able to view Notices of Violation and of Notices

[6] https://echo.epa.gov/detailed-facility-report?fid=110014322170
[7] http://docketpublic.energy.ca.gov/PublicDocuments/12-AFC-02/TN203163_20141003T162359_Helping_Hand_Tools_Comments_Comments_on_the_PMPD_and_FDOC_on_Be.pdf
[8] http://docketpublic.energy.ca.gov/PublicDocuments/12-AFC-02/TN203223_20141021T143703_Energy_Commission_Staff's_Response_and_Comments_to_the_Revised.pdf

to Comply for the facility. From November 16, 2016, the web page for AES Redondo Beach (ID 115536), reproduced below as reference, shows all Notices of Violation (NOV) are cancelled, closed case, rejected or void, except for P60572. Clicking on the P60572 link provides additional details, including that the Follow Up Status is "In Compliance." The reason the case is not closed is that the NOV is awaiting disposition by a District prosecutor. Further, the facility is in compliance with all Notices to Comply, including E27765, which was issued earlier this year. Therefore, AES is currently in compliance with Rule 1303(b)(5)(B) requirements.

Compliance

Facility ID	115536
Company Name	AES REDONDO BEACH, LLC
Address	1100 N. HARBOR DR
	REDONDO BEACH, CA 90277

Notices Of Violation

Notice Number	Notice Issue Date	Violation Date	Disposition Date	Disposition
P28068	4/13/2001	11/17/1999	8/21/2002	Closed Case
P28718	8/28/2001	1/1/1999	2/1/1999	Void
P28719	9/5/2001	1/1/1999	8/21/2002	Closed Case
P37100	1/29/2002	1/1/2000	8/15/2002	Rejected
P37110	5/30/2003	3/2/2003	5/31/2005	Closed Case
P37113	6/4/2003	1/1/2003	5/31/2005	Closed Case
P37136	10/25/2005	1/1/2003	5/23/2006	Closed Case
P43494	8/31/2006	8/9/2006	3/20/2007	Closed Case
P51953	8/14/2008	7/4/2008	12/5/2008	Closed Case
P52177	5/25/2011	1/1/2010	7/17/2012	Closed Case
P52192	6/21/2013	5/25/2012	4/15/2014	Closed Case
P55513	12/4/2009	4/22/2008	4/20/2010	Cancelled
P55516	6/15/2010	4/3/2009	10/28/2010	Closed Case
P60556	11/6/2014	9/28/2013	4/28/2015	Closed Case
P60572	7/6/2016	8/6/2015		

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Notices To Comply

Notice Number	Violation Date	Re-Inspection Date	Status
C56850	11/17/1999	12/16/1999	In Compliance
C57169	12/21/2000	5/3/2001	In Compliance
D04855	1/19/2007	12/18/2007	In Compliance
D21309	10/1/2009	1/5/2011	In Compliance

E00711	1/1/2010	2/11/2010	In Compliance
E00713	1/1/2010	3/8/2011	In Compliance
E09958	2/10/2012	5/11/2012	In Compliance
E09967	1/17/2014	2/18/2014	In Compliance
E27752	6/27/2013	11/6/2014	In Compliance
E27758	1/1/2014	5/22/2015	In Compliance
E27765	2/29/2016	5/31/2016	In Compliance

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10. Alternatives Analysis

Rule 1303 requires the district to conduct an alternatives analysis. Under this procedure, a full analysis of the proposal is conducted, including project alternatives. According to the PDOC technologies considered were "Conventional Boiler and Steam Turbine, Kalina Combined-Cycle, Geothermal and Hydroelectric, Internal Combustion Engine, Biomass, Wind, and solar." Just like the CEC in the previous HBEP application the alternatives analysis fails to consider electrical storage as a feasible replacement for one or both for the LMS- 100 PB units. AES the applicant for the HBEP is currently developing a 100 MW battery for use in Los Angeles that is expected to be deployed in 2021 before the proposed LMS-100 PB's are scheduled to begin operation. While at one time storage was not a feasible alternative it is certainly a feasible alternative for one or both of the LM-100 PB turbines proposed for this project and must be considered in the Districts alternative analysis.

SCAQMD Response

The HBEP PDOC explains that the requirements of Rule 1303(b)(5)(A) may be met through compliance with CEQA, and Rule 2005(g)(3) specifies the requirements of paragraph Rule 2005(g)(2) may be met through CEQA analysis. Both of these rules are SIP-approved by EPA (http://www.aqmd.gov/home/regulations/rules/sip-approved-rules). CEQA is designed to assure that all potential environmental impacts are reviewed prior to permitting a major project, and CEQA environmental review is fully integrated into the CEC siting process. Under state law, the preparation of the CEQA analysis is done by CEC for a project subject to CEC jurisdiction.

The CEC prepared a Preliminary Staff Assessment (PSA), which includes an environmental assessment of air quality, alternatives, biological resources, cultural resources, hazardous materials management, land use, noise and vibration, public health, socioeconomics, soil & water resources, traffic & transportation, transmission line safety & nuisance, and visual resources, and an engineering assessment of facility design, geology & paleontology, power plant efficiency, power plant reliability, transmission system engineering, waste management, and worker safety & fire protection. The CEC concluded that with implementation of staff's recommended mitigation measures described in the conditions of certification, the HBEP would comply with all applicable laws, ordinances, regulations, and standards (LORS).

As the agency responsible for air quality, the SCAQMD performed an evaluation of environmental costs related to air quality by preparing a detailed PDOC that concluded the proposed HBEP, with the required mitigation, will not result in significant air quality impacts and will comply with all applicable federal, state and local air quality rules and regulations. This analysis was considered by CEC staff and incorporated, as appropriate, into the CEC PSA.

CEC uses information provided by the applicant, the SCAQMD, and other sources in preparing its' staff analyses, including its EIR-equivalent analysis.

First, AES and CEC have determined there are no alternative projects or alternative sites or mitigating measures which would offer more protection to the environment than the proposed project without unduly curtailing non-environmental benefits.

<u>Alternatives Study</u>
AES and the CEC provided an alternatives study in the initial licensing procedure and determined there was no new information to analyze for the amended license petition. As explained above, the SCAQMD relies on the CEQA analysis, including the alternatives analysis, prepared by the CEC.

<u>Applicant</u>
The alternatives considered include the "no project" alternative, power plant site alternatives, alternative project design features (alternative natural gas supply pipeline routes, electrical transmission system alternatives, water supply alternatives), technology alternatives (generation technology alternatives, conventional boiler and steam turbine, nuclear, Kalina combined-cycle, internal combustion engines), fuel technology alternatives, NOx control alternatives, and waste discharge alternatives. The conclusion was that the alternatives considered were either infeasible, unable to reduce or avoid any adverse environmental impacts, or would not attain most of the basic objectives of the project.

<u>CEC</u>
In Section 6.1 of the PSA, the CEC provides an analysis of alternatives. The CEC concludes: ""Staff reviewed alternatives previously analyzed for the licensed Huntington Beach Energy Project (HBEP) design and related facilities, alternative technologies, and the "no project" alternative. Alternatives previously found to be infeasible remain infeasible, and would not substantially reduce one or more significant effects of the amended HBEP. In addition, no new information shows alternatives which are considerably different from those analyzed in the previous staff assessment for the licensed HBEP that would substantially reduce one or more significant effects on the environment."

Instead of merely using the applicant's project objectives as a yardstick as asserted by the commenter, the CEC provided a broad interpretation of the applicant's project objectives, then reviewed the objectives for consistency with the State Water Resources Control Board's *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy), California Independent System Operator (CAISO) planning, state's Renewable Portfolio Standard (RPS), state energy policies and procurement planning, CPUC decisions, and North American Electric Reliability Council and the Western Electricity Coordinating Council reliability standards. The alternatives evaluation included "preferred resources" (energy efficiency, demand response, utility scale and distributed renewable generation, and **energy storage**), alternative sites, and no-project alternative.

On page 6-9, the CEC explains that natural gas-fired generation is necessary because preferred resources, including energy storage, cannot ensure reliability

On page 1-5, the CEC concluded: "In accordance with CEQA Guidelines section 15126.6(f)(2)(C), staff reviewed alternatives previously analyzed for the licensed HBEP design and related facilities, alternative technologies, and the "no project" alternative. Alternatives previously found to be infeasible would not now be feasible, and would not substantially reduce one or more significant effects of the licensed HBEP. Similarly, new information does not show alternatives which are considerably different from those analyzed in the previous staff assessment for the licensed HBEP that would substantially reduce one or more significant effects on the environment."

As discussed below, the relative price ("cheaper") is not included in the criteria of environmental and social cost.

Energy Storage as Feasible Alternative

The commenter has focused on energy storage as an alternative and asserts that energy storage is feasible to replace up to four of the proposed simple-cycle turbines. Both AES and CEC found energy storage not to be a feasible alternative to replace any of the simple-cycle turbines. The commenter has not provided an analysis to support his assertion that energy storage is a feasible alternative.

In response to the SCAQMD's request for more information regarding the AES battery storage projects, AES indicated it is developing a 100 MW Battery Energy Storage System (BESS) at the Alamitos Generating Station site, with an expected online date of 1/1/2021, in response to a power purchase agreement award from Southern California Edison (SCE). AES is in the process of permitting the BESS through the local jurisdiction to accommodate 300 MWs of storage capacity for potential future expansion. The BESS is not an alternative to the electrical generation capability of the simple-cycle turbines, but a complement. Through dispatch orders from the California Independent System Operator (CAISO), SCE will determine when the simple-cycle turbine(s) will be called upon to generate electricity (dispatched) and when the BESS will be called upon to be discharged to meet electrical demand. In general, the more expensive source of energy is less competitive. This means the simple-cycle turbines, once installed, will be available when needed, but may not be called upon to be dispatched. Thus the combined-cycle turbines, simple-cycle turbines and BESS each will serve a different role in maintaining an efficient and reliable electrical grid, with the combined-cycle block scheduled for first fire on 10/1/19 and the simple-cycle block for 6/1/21. As California builds out its renewable generation and energy storage facilities in response to the renewable energy requirements of Senate Bill 350 to increase the percentage of renewable energy from 33 percent to 50 percent by 2030, the role of the combined- and simple-cycle turbines will evolve over time.

Second, the SCAQMD and CEC have evaluated impacts and imposed mitigation to ensure that the adverse impacts of the proposed facility have been avoided to the maximum extent possible.

SCAQMD

The SCAQMD's evaluation of air quality impacts and imposition of required mitigation measurements are detailed in the PDOC, and summarized below.

- Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) will be required to limit NOx, CO, VOC, PM_{10}, SOx, and ammonia (NH_3) emissions from the combustion equipment.
  - The combined- and simple-cycle turbines each will be controlled by dry low-NOx combustor and selective catalytic reduction system for NOx and an oxidation catalyst for CO and VOC.
  - The auxiliary boiler will be controlled by low NOx burner, flue gas recirculation, and selective catalytic reduction system for NOx, and good combustion practice for CO.
  - BACT emission levels for NOx, CO, VOC, and NH_3 for the combined- and simple-cycle turbines, and NOx, CO, and NH3 for the auxiliary boiler are specified by permit condition. SCAQMD has carefully reviewed and responded to the commenter's comments on BACT levels for VOC, PM_{10}, and CO for combined- and simple-cycle turbines, above.
  - BACT for PM_{10} and SOx for the combined- and simple-cycle turbines, and VOC, PM_{10} and SOx for the auxiliary boiler require the use of pipeline quality natural gas with an annual average hydrogen sulfide content of no greater than 0.25 grain per 100 scf. Natural gas is the cleanest and lowest greenhouse gas-emitting fossil fuel available.
  - The combined- and simple-cycle turbines are equipped with NOx and CO CEMS, and the auxiliary boiler is equipped with a NOx CEMS.
  - The combined- and simple-cycle turbines and the auxiliary boiler are required to pass an initial source test for NOx, CO, SOx, VOC, PM_{10}, $PM_{2.5}$, and NH_3 before the Permits to Construct may be converted to Permits to Operate.
  - Subsequent to the initial source test, the combined- and simple-cycle turbines are required to pass a source test for SOx, VOC and PM_{10} at least every three years. The auxiliary boiler is required to pass a source test for CO pursuant to the testing frequency specified in SCAQMD Rule 1146. The turbines and boiler are required to pass the NH3 source test at least quarterly during the first twelve months of operation and at least annually thereafter.

- Best Available Control Technology for Toxics (T-BACT) requires an oxidation catalyst to limit toxic emissions from the combined- and simple-cycle turbines.

- Offsets will be provided for the increase in criteria pollutants for the combustion equipment.
  - For the combined- and simple-cycle turbines, AES will pay for the PM_{10} and VOC offsets from the SCAQMD internal account pursuant to Rule 1304.1. The Rule 1304(a)(2) replacement exemption is for modeling and offsets. Offsets become available only upon the permanent shutdown (retirement) of a utility boiler. Condition F52.1 requires a detailed SCAQMD-approved retirement plan for the permanent shutdowns.
  - For the auxiliary boiler, AES has provided emission reduction credits (ERCs) for $PM_{10,}$ SOx, and VOC emissions.
  - For the turbines and auxiliary boiler, AES will provide RECLAIM Trading Credits (RTCs) for the NOx and SOx emissions pursuant to RECLAIM regulations.

- SCAQMD Planning, Rule Development & Area Sources (PRDAS) staff reviewed the applicant's dispersion modeling analysis, including the health risk assessment results, by independently reproducing the modeling analysis, to verify compliance with SCAQMD rules and in support of the CEC's CEQA analysis. The results of that review can be referenced in the PDOC.

- For the combined- and simple-cycle turbines, permit conditions limit CO_2 emissions in terms of tons per year per turbine on a 12-month rolling average basis and in lbs per gross megawatt-hours to ensure compliance with greenhouse gas BACT and with 40 CFR 60 Subpart TTTT-Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units.

- Maximum monthly emission limits and annual emission limits, where appropriate, based on commissioning, normal operation, start-ups, and shutdowns, are imposed by permit condition for the combustion equipment to ensure compliance with offset, ambient air quality modeling, and health risk assessment requirements. Commissioning is limited in duration for total hours and hours without control. Startups and shutdowns are limited in number, duration, and emissions per event.

- SCAQMD has determined the proposed HBEP, with implementation of the imposed mitigation measures to reduce air impacts to less than significant, will comply with all applicable federal, state and local air quality rules and regulations.

<u>California Energy Commission</u>
The CEC staff's evaluation of impacts, including on the environmental justice (EJ) population, and imposition of required mitigation measurements are detailed in the PSA.

- <u>Air Quality</u>

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

See PSA for the evaluation of impacts, including on the environmental justice (EJ) population, and imposition of required mitigation measurements, for the areas of :
- Biological Resources
- Cultural Resources
- Hazardous Materials Management
- Land Use
- Noise and Vibration
- Public Health
- Socioeconomics
- Soil and Water Resources
- Traffic and Transportation
- Transmission Line Safety and Nuisance
- Visual Resources
- Facility Design
- Geology & Paleontology
- Power Plant Efficiency
- Power Plant Reliability

- Transmission System Engineering
- Waste Management, and
- Worker Safety and Fire Protection

Based on the CEC analysis in their PSA, the SCAQMD concludes that the adverse impacts of the proposed facility have been avoided to the maximum extent possible.

Third, a cost benefit analysis of the environmental and social cost balanced against the social, economic, and environmental benefits of the project demonstrate that the latter outweigh the former.

Environmental Impact Costs
The SCAQMD and CEC have evaluated environmental and social cost and imposed mitigation measures to ensure that the adverse impacts of the proposed facility have been avoided to the maximum extent possible, as discussed above.

Social, Economic, Environmental Benefits
The social, economic, and environmental benefits of the project include:

- Provide operationally flexible generating capacity and ancillary electrical services (voltage support, spinning reserve, inertia) to the southern Orange County and San Diego area and to serve reliability needs and peak southern California energy demand.
  - Meet demand for new generation caused in large part by the closure of the San Onofre Nuclear Generating Station and the anticipated retirement of older, natural-gas-fired generation currently using once-through ocean water cooling, such as the existing Huntington Beach Generating Station, by December 31, 2020.
  - Provide fast starts and ramp-up/ramp-down capability that allow HBEP turbines to shut down when not needed, in contrast to the existing steam utility boilers which need to be maintained on stand-by load.
  - Provide superior thermal efficiency as compared to the existing steam utility boilers.
  - Support local electrical reliability and grid stability to allow the integration of intermittent, renewable energy into the electrical grid and enable attainment of California's Renewable Energy Portfolio Standards (RPS).
  - Serve the southern Orange County and San Diego load center without constructing new transmission facilities.
  - Use substantially less fresh water than the existing Huntington Beach Generating Station has historically used. The existing steam utility boilers generate power with steam only, whereas the proposed turbines generate power mechanically and with steam.
  - Result in reduced visual impact compared to the existing Huntington Beach Generating Station due to HBEP's shorter exhaust stacks.
  - Avoid potential impacts to critical habitats and other wildlife areas by locating the project on the brownfield site of the existing Huntington Beach Generating Station.
  - Minimize potential land use impacts by reusing existing infrastructure.

Therefore, the SCAQMD concludes that the many benefits outweigh the environmental impacts of the project, which have been avoided or minimized through application of stringent mitigation measures and compliance with all applicable federal, state and local rules and regulations.

11. <u>Collateral Impacts from use of Ammonia</u>

The PDOC proposes SCR for the control of NOx emissions from the HBEP. The PDOC selects SCR over other technologies but fails to discuss the collateral impacts from the use of ammonia in the SCR. The existing Huntington Beach power plant has a urea to ammonia conversion unit. Currently urea pellets are transported and converted to ammonia onsite at the power plant. Use of urea pellets eliminates the impacts of transportation and storage of large amounts of ammonia for use in the SCR. That is the current environmental baseline. AES recognizes the importance of the use of urea at its power plant. On the AES website it states that Huntington Beach is, "the first plant in the nation to use a urea to ammonia conversion system — eliminating the need to transport ammonia through our community."

In addition according to the PDOC the nearest inhabitants to the proposed project site are located in a residential area approximately 300-400 feet from the site. The project proposes two ammonia storage tanks. One is a 35,000 gallon aqueous ammonia storage tank serving the CCTG and auxiliary boiler and a 15,000 gallon aqueous ammonia storage tank serving the SCTG. A catastrophic accidental release from the ammonia storage tanks can be prevented by the continued use of urea at the site and a collateral impact from the use of SCR can be eliminated. The current urea system is BACT for the SCR and has been shown to be feasible and cost effective at is already in use at the site.

The storage of large amounts of aqueous ammonia also presents security issues related to terrorist attacks requiring additional security onsite to prevent such incidents. The use of urea pellets eliminates that risk. The FDOC should require the use of urea and prevent the hazards from the transportation and use of aqueous ammonia and possible terrorist implications.

<u>SCAQMD Response</u>

Urea conversion technology uses solid urea (prill) in a reactor with steam to convert the urea to aqueous ammonia, which is typically stored in a tank for use by the SCR system during upsets in the process and plant startup activities. Although the urea conversion technology has been employed for power plants for a number of years, it only eliminates the need to truck aqueous ammonia to the site, because onsite ammonia storage is always included in the system design. Furthermore, the urea conversion process has a higher energy demand over an aqueous ammonia system as a result of consuming steam as part of the process. Finally, the urea process has proven to have poor reliability and slow response times, and it produces an inconsistent concentration of ammonia. The HBEP combustion turbines are designed to be fast-start and fast-ramp units that require precise control of ammonia concentrations for emissions control. Therefore, urea conversion was considered and rejected." This assessment was based on AES's operating experience with Units 1-4 at the existing Huntington Beach Generating Station, which uses a urea-to-ammonia conversion system to supply ammonia to the selective catalytic reduction systems (SCRs) for these utility boilers.

An assessment of risks of ammonia transport is properly a part of the CEQA analysis. The California Energy Commission, as the lead agency under the CEQA equivalent process used for power plant licensing, performed a hazardous materials management analysis. The CEC staff concluded the proposed HBEP's storage and use of hazardous materials at the site, including aqueous ammonia, would not present a significant impact to the public, with the adoption of the proposed conditions of certification. The proposed project would comply with all applicable laws, ordinances, regulations, and standards.

The offsite consequence analysis to assess potential impacts associated with an accidental release of aqueous ammonia and proposed engineering and administrative controls. CEC staff performed an offsite consequence analysis, through the use of an EPA-approved plume modeling program, for a spill from the tanks and found that plume concentrations of 75 ppm, the level of significance, would not occur offsite, even for the worst case scenario. The proposed conditions of certification include requiring the secondary containment structure to incorporate essential design elements to prevent a worst-case spill from producing significant off-site impacts, and the implementation of a safety management plan that would include the use of both engineering and administrative controls. The administrative controls include the development by AES of a worker health and safety program, a safety management plan for the delivery of all liquid hazardous materials including aqueous ammonia, a risk management plan for aqueous ammonia, and a hazardous material business plan.

CEC performed a risk assessment for the transportation of the aqueous ammonia by tanker truck. CEC staff used a transportation risk assessment model to calculate the probability of an accident resulting in a release of a hazardous material due to delivery from the freeway to the facility via Studebaker Road. The CEC staff believes that the risk of exposure to significant concentrations of aqueous ammonia during transportation to the facility is insignificant because of the remote possibility that an accidental release of a sufficient quantity would occur would be very unlikely. The proposed conditions of mitigation include the use of only the specified and California Highway Patrol-approved route to the site.

Therefore, the the SCAQMD believes that proposed use of aqueous ammonia is an acceptable alternative to the urea to ammonia conversion system.

In response a similar comment made by the Helping Hand Tools back in 2014 to CEC on the Revised Presiding Member's Proposed Decision for the Huntington Beach Energy project, the CEC staff's response is produced below[9]:

> *Staff analyzed the risk of tank failure during an earthquake in the FSA and found "that tank failures during seismic events are not probable and do not represent a significant risk to the public." (Ex.2000, TN #202450, FSA. page 4.4-14) Staff's evaluation of the proposed project, with proposed mitigation measures, indicates that the hazardous material use of 19% aqueous ammonia will pose no significant impact to the public. Therefore, the proposed use of aqueous ammonia is an acceptable alternative to the urea to ammonia conversion system surrently used by the HBGS on-site.*
>
> *Staff modeled a potential worst-case event involving the total loss of containment of the entire contents of the full tank, and found that with the secondary containment requirements of condition of certification HAZ-4 the resulting air-borne plume would not produce hazardous concentrations of ammonia vapor beyond the facility's fence line (Ex.2000, TN #202450, FSA, page 4.4-10).*

[9] http://docketpublic.energy.ca.gov/PublicDocuments/12-AFC-02/TN203223_20141021T143703_Energy_Commission_Staff's_Response_and_Comments_to_the_Revised.pdf

Staff also reviewed the risks of a terrorist attack during construction and operation and proposed conditions of certification HAZ-7 and HAZ-8 for construction and operations site security which would "ensure that neither this project nor a shipment of hazardous material is the target of unauthorized access" (Ex.2000, TN #202450, FSA, page 4.4-15). Tools' comment regarding the use of aqueous ammonia is therefore without merit.

12. Secondary Particulate formation from Ammonia Emissions

According to the PDOC the HBEP CECP has the potential to emit 105.3 tons per year of ammonia. It is well documented that ammonia emissions in the South Coast Air Quality Management District lead to the formation of secondary particulate. The SCAQMD has performed modeling for its rule 1105.1 that demonstrates that 1.5 tons of ammonia emitted can form from 1.5 tons to 6 tons of secondary particulate a day. SCAQMD has successfully defended its environmental analysis for its Rule 1105.1 in court which demonstrated that 1.5 tons per day of ammonia, when released in to the atmosphere would react with other pollutants to form between 1.5 tons per day and 6 tons per day of PM10.

The FDOC should analyze permits that limit ammonia slip to less than 5 ppm and determine if it is feasible to meet a lower ammonia slip limit for this facility. Several recent permits have contained potential lower ammonia slip limits based on the projects actual ammonia emissions over a trial period generally 2 years. The Energy Commission Staff has recommended that projects consider continuous ammonia monitors because the BAAQMD has established this as an optional means of verification in the license for the Marsh Landing Generating Station (District Application 18404, Final Determination of Compliance, June 2010). The District should consider adding a similar requirement to the HBEP ATC.

SCAQMD Response

The PDOC indicates the HBEP has the potential to emit 103.5 tons per year of ammonia, which is based on an ammonia slip concentration that is continuously 5 ppmv. These emissions are conservative because the ammonia slip is lower than 5 ppmv when the catalyst is new and increase over the life of the catalyst. In addition, the emissions are based on maximum permitted annual hours. It is unlikely, however, that the turbines will be operated at the maximum permitted hours because of the integration of higher amounts of renewable energy onto the southern California electrical grid. Offsets are not provided because the SCAQMD requires BACT/LAER but not offsets for ammonia emissions in Regulation XIII (Rule 1303).

Moreover, Rule 1325, which is specific to $PM_{2.5}$, does not include ammonia as a precursor in the SIP-approved version. 80 Fed Reg 24821 (May 1, 2015). On November 4, 2016, Rule 1325 was amended to include ammonia as a precursor but this is not effective until August 14, 2017, or EPA approval of the November 4, 2016 amendment, whichever is later.

The PDOC indicates the HBEP has the potential to emit 11.4 tons per year of SOx, which is based on an average of 0.25 grains/100 scf average total sulfur content in the natural gas. These emissions are conservative because the fuel sulfur content has historically been lower than 0.25 grains/100 scf. In addition, the emissions are based on maximum permitted annual hours, but it is unlikely, however, that the turbines will be operated at the maximum permitted hours. The comment asserts that offsets are not provided for SOx. As stated in the PDOC, SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects, but the offsets are provided from the SCAQMD internal offset accounts. Because the HBEP is in the SOx RECLAIM market, SOx offsets will be provided through RECLAIM Trading Credits for the turbines and auxiliary boiler.

The comment states that the PDOC proposes to limit PM emissions to 69.6 tons per year but with the secondary formation of PM from the ammonia slip and SOx, the project will obviously emit more than 100 tons per year of $PM_{2.5}$ and therefore is required to meet the requirements of Appendix S. As noted above, ammonia is not currently a precursor in Rule 1325. Moreover, the project is not subject to Appendix S, which only applies before a nonattainment area has a SIP-approved NSR rule. The NSR Rule 1325 for $PM_{2.5}$ is SIP-approved. EPA's August 24, 2016 $PM_{2.5}$ Implementation Rule, in 81 Fed Reg 58010 (August 24, 2016), allows areas to rely on an existing SIP-approved NSR rule until revisions are approved by EPA.

The commenter asserts that secondary particulate emissions from ammonia and SOx emissions are required to be added to the permitted 69.6 tons per year of directly emitted $PM_{2.5}/PM_{10}$ for the purposes of Rule 1325 applicability. The commenter relies on the SCAQMD's analysis of secondary particulate formation performed for the adoption of Rule 1105.1-- Reduction of PM_{10} and Ammonia Emissions from Fluid Catalytic Cracking Units. The reliance on Rule 1105.1, adopted on 11/7/2003, is misplaced because the purpose of that rule is to limit filterable PM_{10} and ammonia slip from existing, new or modified fluid catalytic cracking units at petroleum refineries. This rule does not require offsets for secondary particulate emissions for the purpose of New Source Review (Rule 1303) or for PSD (Rule 1325).

The 69.6 tons/year PM_{10} already includes the formation of primary ammonium sulfate particulates in the exhaust of the combined- and simple-cycle turbines with the assumption of the conversion of sulfur into ammonium sulfates as a result of the use of oxidation and reduction catalysts. The turbine exhaust emission rates were provided in the vendor guarantees and the ammonium sulfates emission rates were calculated by CH_2M Hill, AES's environmental consultant. The ammonium sulfate emissions were conservatively calculated based on turbine technology, maximum fuel sulfur content, emission control equipment and engineering judgment.

The commenter asserts that several recent permits have contained potential lower ammonia slip limits than 5 ppm based on the projects actual ammonia emissions over a trial period generally 2 years, but does not list the projects, or provide any citations to supporting documentation. The SCAQMD's search of the EPA RACT/BACT/LAER Clearinghouse, Statewide Best Available Control Technology (BACT) Clearinghouse, and other databases for lower ammonia slip emission limits for other recently permitted natural gas-fired combustion turbines are summarized as follows:

- <u>Simple-Cycle Turbines</u>
  No facilities with an ammonia slip limit of less than 5 ppmvd were found. Therefore BACT remains 5 ppmvd at 15% O_2.

- <u>Combined-Cycle Turbines</u>
  The EPA RACT/BACT/LAER Clearinghouse shows three facilities with an ammonia slip limit of less than 5 ppmvd at 15% O_2. The following three facilities were shown having an ammonia slip limit of 2 ppmvd at 15% O_2, and a NOx limit of 2.0 ppmvd at 15% O_2.

1) Kleen Energy Systems, LLC—Commercial operation started in July 2011. The 2.0 ppmvd at 15% O2 has been verified on the EPA RACT/BACT/LAER Clearinghouse database. The permit, dated 7/2/13, indicates a 2.0 ppmvd ammonia slip limit is applicable during steady state operation, and a 5.0 ppmvd ammonia slip limit is applicable during transient operation. Transient operations include cold, warm and hot startups, shut-downs, shifts between loads, fuel switch and equipment cleaning, as well as operation below 60% load. In contrast, the SCAQMD does require BACT during periods of shifts between loads and operation at below 60% load. As HBEP turbines are equipped with fast start and ramp-up/ramp-down capabilities, load changes are expected to be a regular occurrence. As the minimum turndown for the turbines is 44% load, operation at below 60% load is expected to be a regular occurrence. The Kleen Energy System limits do not meet the definition of BACT as implemented by the SCAQMD for a facility with these operating characteristics.

   The permit limits for Kleen Energy are not achieved in practice for facilities where BACT must be met during shifts between loads and at below 60% load. Condition D29.2 requires the initial source testing for combined-cycle turbines to be performed at 45, 75, and 100 percent of maximum load, and for the simple-cycle turbines at 50, 75, and 100 percent of maximum load, because emission rates may vary with load.

2) Salem Harbor Station Redevelopment—Scheduled to start operation in June 2017. The permit, dated 1/30/14, does not include an ammonia slip limit.

3) CPV Towantic, LLC—Scheduled to be on line in 2018. The 2.0 limit has not been demonstrated to be achieved in practice.

Therefore, the BACT/LAER ammonia slip limit for simple- and combined-cycle turbines remains 5.0 ppmvd at 15% O2.

The commenter asserts that CEC staff has recommended that projects consider continuous ammonia monitors, but the PSA for HBEP does not make any such recommendation. The commenter asserts the reason for this recommendation is that BAAQMD established this as an optional means of verification in the license for the Marsh Landing Generating Station, as set forth in the FDOC, dated June 2010, and the SCAQMD should add a similar requirement for the HBEP project. The most recent Marsh Landing permit, dated 11/3/2015, includes condition 17.e, which specifies: "The APCO may require the installation on one exhaust point (P-1, P-2, P-3, or P-4, at the owner/operator's discretion) of a CEM designed to monitor ammonia concentrations if the APCO determines that a commercially available CEM has been proven to be accurate and reliable and that an adequate Quality Assurance/Quality Control protocol for the CEM has been established. The District or another agency must establish a District approved Quality Assurance/Quality Control protocol prior to the ammonia CEM being a requirement of this part. The ammonia CEM shall be used to demonstrate compliance with the ammonia emission limit contained in this Part for the gas turbine being monitored." This condition does not establish a continuous ammonia monitor as a viable option. The condition provides a possible option should the technology be developed.

At this time, neither the EPA nor the SCAQMD has developed an approved protocol for ammonia CEMS. The SCAQMD has not certified any ammonia CEMS for determining compliance with permit limits. To predict ammonia slip, the SCAQMD has established the ammonia slip calculation procedures which require the operator to calculate and continuously record the ammonia slip using the provided equations, which incorporate the NOx CEMS readings. The proposed permit requires an initial source test for ammonia (and other pollutants), using a protocol approved by the SCAQMD Source Test Engineering Dept, for the turbines and auxiliary boiler SCRs to confirm that the ammonia slip meets the 5 ppm limit. The source test is required to be approved by the SCAQMD Source Test Engineering Dept before the Permits to Construct may be converted to Permits to Operate. Ammonia slip testing is required at least quarterly during the first twelve months of operation and at least annually thereafter for the turbines and the auxiliary boiler.

13. <u>40CFR 51 Appendix S – Federal PM2.5 New Source Review</u>

A major polluting facility is defined as a facility located in a federal non-attainment area which has actual emissions, or a potential to emit of greater than 100 tons per year, of either PM2.5 or its precursors. According to the public notice for the permit the project can emit 69.6 tpy of direct PM 2.5, 71.4 tpy of VOC's, and 105.3 tpy of ammonia. When considering the unmitigated ammonia and VOC emissions the project is a major source for PM 2.5. The PDOC concludes that the project is not a major polluting facility because it apparently concludes that ammonia and VOC emissions are not precursors. But recent court rulings require an affirmative showing that ammonia is not a precursor is necessary to conclude that ammonia emissions are not a precursor to PM 2.5. SCAQMD has attempted to make that showing in its submittals to EPA for approval of its Rule 1325 into the SIP. Rule 1325 has not been approved by EPA and the district has not received EPA concurrence that ammonia emissions are not a precursor to PM 2.5. Ironically SCAQMD has performed modeling for its rule 1105.1 that demonstrates that 1.5 tons of ammonia emitted can form from 1.5 tons to 6 tons of secondary particulate a day. SCAQMD has successfully defended its environmental analysis for its Rule 1105.1 in court.

<u>*SCAQMD Response*</u>

At the SCAQMD Governing Board Meeting on October 7, 2016, a public hearing was set for November 4, 2016 to consider amendments to Rule 1325. Amendments to Rule 1325 are proposed to establish appropriate major stationary source thresholds for direct PM2.5 and PM2.5 precursors, including VOC and ammonia, in order to align with the recent reclassification of the South Coast Basin from a "moderate" PM2.5 nonattainment area to a "serious" nonattainment area and with U.S. EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule. The proposed amendments are intended to facilitate SIP approval of the regulations.

The amendments propose to add ammonia and VOC as precursors to $PM_{2.5}$, per Clean Air Act Subpart 4 requirements. The major polluting facility thresholds will be lowered from the current 100 tons per year per pollutant to 70 tons per year per pollutant. These amendments will be effective after August 14, 2017 or upon the effective date of EPA's approval of these amendments to this rule, whichever is later. U.S. EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule states an area can rely on SIP-approved $PM_{2.5}$ New Source Review rule until the new rule is approved. 81 Fed Reg 58010 (August 24, 2016). The proposed amendments were adopted without change on November 4, 2016.

14. <u>Huntington Beach Unit 1 Retirement</u>

The PDOC requires that, "Within 30 calendar days of actual shutdown, or by no later than November 1, 2019, AES shall provide SCAQMD with a notarized statement that HB Beach Boiler 1 and RB Boiler 7 are permanently shut down and that any re start or operation of the units shall require new Permits to Construct and be subject to all requirements of non-attainment new source review and the prevention of significant deterioration program. Huntington Beach Unit 1 and Redondo Beach Unit 7 are both scheduled to retire on December 31, 2020. It is very possible particularly for Huntington Beach Unit 1 that the plants will be needed for reliability and will not be able to comply with this condition.

SCAQMD Response
Your comment is noted. The November 1, 2019 date was provided by the applicant. The State Water Resources Control Board (SWRCB) Once Through Cooling (OTC) requirements do not preclude early shutdown. Moreover, in accordance with SCAQMD Rule 1313(d), the boilers are only allowed to operate for 90-days once the source that they are offsetting has been brought online. SCAQMD requires a comprehensive boiler retirement plan (permit condition F52.1) which insures the boilers will be rendered inoperable upon retirement. If the boilers are not shut down in accordance with these requirements, the operator is subject to enforcement action.

Response to Comment Letter No. 4

There are a few proposed conditions which are either in error or are inconsistent with the information submitted and subsequent analysis included with the PDOC. The proposed changes to the permit conditions provided below have no impact on the conclusions of the analysis, are consistent with the data submitted to the SCAQMD for analysis, and will allow the proposed equipment to operate as required by the local electrical balancing authority.

Page 14 of the Facility Permit to Operate, Condition F2.1 – Under the heading “Contaminant”, the pollutant listed is particulate matter with an aerodynamic diameter of 10 microns or less (PM10)and the condition is applicable to only particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5).

Response
The condition wording was adjusted to specify “PM 2.5”.

Page 16 of the Facility Permit to Operate, Condition F52.1 – AES requests that the shutdown of Huntington Beach Generating Station Unit 1 be tied to the start up of the first fire of the combined cycle turbine generators (CCTG) and not tied to a specific date of November 1, 2019. In the event that construction of the CCTG is delayed due to unforeseen events, AES may not be allowed by other state agencies to shutdown Unit 1 until the CCTG units are operational, consistent with paragraph 8 of this condition, which allows 90-days of simultaneous operation of the CCTG and Unit 1.

Response
SCAQMD prefers to leave the condition wording as is, since this is the schedule that was presented in the permit application. If there is any delay in the construction schedule of the CCTG which affects

the shutdown date of Boiler #1 AES has the option to submit an application for a permit modification to address the situation.

Page 22 of the Facility Permit to Operate, Condition A195.6 – The sources subject to this condition are D115 and D124. However, the Condition only indicates that source D124 is subject to this condition.

Response
The condition has been amended to address this comment.

Page 23 of the Facility Permit to Operate, Condition A195.9 – There appears to be a typographical error with language describing ammonia (NH3) concentration calculations from Condition A195.10 duplicated in Condition A195.9, a condition for carbon dioxide (CO2) emissions.

Response
The condition has been amended to address this comment.

Page 26 of the Facility Permit to Operate and Page 76 of the PDOC, Condition C1.7 – The start up restrictions are not consistent with the maximum month emissions, place undue operating restrictions on the equipment without justification, and would result in the equipment being unable to respond to dispatch orders from the local balancing authority. Since the warm and hot start up emissions and durations are identical and are in all cases less than the emissions from a cold start, there should be no restriction on hot and warm starts other than the total monthly and annual limits on any start condition. The following revisions to Condition C1.7 are necessary:

The operator shall limit the number of start ups to no more than 62 in any one calendar month.

The number of cold start ups shall not exceed 15 per month, ~~the number of warm start ups shall not exceed 12 per month, and the number of hot start ups shall not exceed 35 per month~~. Additionally, the number of cold start ups shall not exceed 80 per year, the number of ~~warm start ups shall not exceed 88 per year~~, and the total number of ~~hot~~ start ups shall not exceed ~~332~~ 500 per year.

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

A non-cold ~~warm~~ start up is defined as a start up which occurs after the steam turbine has been shutdown for less than 9 – 48 hours. A ~~warm~~ non-cold start up shall not exceed 30 minutes.

Emissions during the 30 minutes that includes a ~~warm~~ non-cold start up shall not exceed the following: NOx - 17 lbs., CO – 137 lbs., VOC –25 lbs.

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

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

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

Response
The condition has been amended to address this comment.

Page 16 of the Facility Permit to Operate and Page 73 of the PDOC, Condition F52.1, 1st Full Paragraph – AES suggests revising this paragraph as proposed below in order to allow for minor delays in the construction and commissioning schedule:

Within 30 calendar days of actual shutdown, or within 90 days after the first fire of either combined cycle turbine generator unit ~~by no later than November 1, 2019~~, AES shall provide SCAQMD with a notarized statement that HB Beach Boiler 1 and RB Boiler 7 are permanently shutdown and that any re start or operation of the units shall require new Permits to Construct and be subject to all requirements of non-attainment new source review and the prevention of significant deterioration program.

Response
SCAQMD prefers to leave the condition wording as is, since this is the schedule that was presented in the permit application. If there is any delay in the construction schedule of the CCTG which affects the shutdown date of Boiler #1 AES has the option to submit an application for a permit modification to address the situation.

Page 43 of the Facility Permit to Operate and Page 102 of the PDOC, Condition D29.9 – The Facility Permit to Operate requires carbon monoxide (CO) testing at the inlet of the selective catalytic reduction (SCR) serving this equipment (the auxiliary boiler), whereas the PDOC Condition D29.9 requires CO testing at the outlet of the SCR. Please revise the Facility Permit to Operate Condition D29.9 to require CO testing at the outlet of the SCR.

Response The condition has been amended to address this comment.

Page 47 of the Facility Permit to Operate and Page 82 of the PDOC, Condition E193.5 – The hours in this condition should specify "fired" hours as the combustion turbines can be operated without fuel firing for testing purposes, as proposed below:

E193.5

The operator shall install this equipment according to the following requirements:

Total commissioning hours shall not exceed 996 fired hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 216 fired hours of operation for each turbine.

Response The word "fired" does not need to be added because its understood that "hours of operation" is defined as fired hours.

Page 49 of the Facility Permit to Operate and Page 94 of the PDOC, Condition E193.7 – The hours in this condition should specify "fired" hours as the combustion turbines can be operated without fuel firing for testing purposes, as proposed below:

E193.7

The operator shall install this equipment according to the following requirements:

Total commissioning hours shall not exceed 280 fired hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 4 fired hours of operation for each turbine.

Response The word "fired" does not need to be added because its understood that "hours of operation" is defined as fired hours.

Page 53 of the Facility Permit to Operate and Page 83 of the PDOC, Condition I297.1 – Please revise the Facility Permit to Operate Condition I297.1 to be consistent with the PDOC Condition 297.1 as follows:

I297.1

This equipment shall not be operated unless the facility holds 147093 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation.
The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are heldone year from the initial start of operation. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

Response
The condition has been amended to address this comment.

Page 55 of the Facility Permit to Operate and Page 95 of the PDOC, Condition I297.2 – Please revise the Facility Permit to Operate Condition I297.2 to be consistent with the PDOC Condition 297.2 as follows:
I297.2

This equipment shall not be operated unless the facility holds 26970 pounds of NOx RTCs in its allocation account to offset the annual emission increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are heldone year from the initial start of operation. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

Response
The condition has been amended to address this comment.

Page 57 of the Facility Permit to Operate and Page 84 of the PDOC, Condition K67.5 – In light of the comment made to Condition C1.7 regarding the start up definitions, AES suggests deleting the parenthetical "(cold, warm, or hot)" from this condition.

Response
The condition has been amended to address this comment.

PDOC Comments

AES also offers the following corrections to information contained within the PDOC.

Page 5, Section H – The simple-cycle turbine generator (SCTG) SCR height should be 11.5', not 11.6'.

Page 6, Section H – The SCTG SCR height should be 11.5', not 11.6'.

Response
The necessary changes have been made to address this comment. Please be aware that an email from Jerry Salamy dated 4/15/16 provided the height of the SCTG SCR as 11.6'. Responses to data requests and PDOC review efforts should be better coordinated within your office to avoid confusion and additional work on everyone's part.

Page 10, Footnote 1 – The maximum annual generation is not correct, as the data used does not match that in the revised air permit application. The CCTG should operate 6,640 hours (including starts and shutdowns) and the SCTG should operate 2,001 hours (including starts and shutdowns). Additionally, the SCTG baseload rating should be 201.6 megawatts (MW).

Response
The calculations were redone using the hours for normal operation (not start ups and shutdowns) and adjusted rating for the SCGT.

Page 17, Table 2.7 – The uncontrolled SCTG oxides of nitrogen (NOx) emission rate is 25 parts per million (ppm), not 9 ppm, as noted in the accompanying text following Table 2.7.

Response
The correction has been made to address this comment.

Page 22, Table 3.1 – The CCTG hot and warm start emissions and duration are identical and for clarity the SCAQMD should describe these as a single start type (i.e., non-cold).

Response

The permit application presented the warm and hot starts as separate, and our analysis followed this format. Combining the warm and hot starts does not change emission estimates or conclusions, so we will not make the requested change.

Page 24, Table 3.6 – The auxiliary boiler startup volatile organic compound (VOC) emissions for a cold, warm, and hot start should be 4.69, 2.34, and 0.69 pounds per event (lbs/event), respectively, instead of 1.05, 0.52, and 0.15 lbs/event, respectively. This change will also need to be made in Appendix D, Tables D.3 through D.12.

Response
Since there is no control equipment abating the VOC emissions on the boiler, it's not clear why the VOC startup emissions would be higher than normal operation. SCAQMD generally only recognizes an increased emission rate during start up in cases where post combustion control equipment with operating temperature requirements is involved.

Page 25, Table 3.7 – Table 3.7 assumes that the CCTGs only operate 23 hours per day (including starts and shutdowns), with one hour of downtime (see Appendix A, Table A.9). The maximum CCTG emissions should be based on the CCTGs operating 24 hours per day, at either full load or including 2 starts and 2 shutdowns

Page 25, Table 3.8 – Table 3.8 assumes that the SCTGs only operate 23 hours per day (including starts and shutdowns), with one hour of downtime (see Appendix B, Table B.8). The maximum SCTG emissions should be based on the SCTGs operating 24 hours per day, at either full load or including 2 starts and 2 shutdowns.

Response
The maximum daily emissions calculations are only performed for informational purposes. Daily emissions are not used in any permit condition or limit. The assumption of a 1 hour down time is included in the calculation to more realistically estimate the emissions, as typically there will be down time after a shutdown before a subsequent start up.

Page 26, Table 3.12 – The operating scenario for Table 3.12 should indicate 222.4 hours of normal operation, consistent with Table 3.4.

Response
The correction has been made to address this comment.

Page 27, Table 3.13 – In the Alamitos Energy Center permit application (Facility ID 115394), the SCAQMD accepted an oil/water separator (OWS) emission factor of 0.00002 pounds of VOC per

1,000 gallons of throughput. Using this emission factor for the HBEP OWS, conservatively assuming the annual throughput can occur in one month, changes the Table 3.13 OWS VOC emissions to 0.017 pounds for OWS 1 and 0.0022 pounds for OWS 2. The OWS VOC emissions in Appendix F should be revised accordingly.

Response
The original OWS calculations presented by AES in the HBEP application are deemed representative of the VOC emissions from the equipment and a change to the emissions methodology is not warranted at this late stage in the permitting process regardless of what was accepted for Alamitos.

Page 29, Table 3.17 – The ammonia operating scenario should not include start up and shutdown hours, consistent with Appendix D, Tables D.11 and D.12.

Response
The table is correct. Annual emissions are based on the maximum allowed start up/shutdown scenario only, there is not a “no start/no shutdown” scenario for annual emissions.

Page 29, Table 3.18 – In the Alamitos Energy Center permit application (Facility ID 115394), the SCAQMD accepted an OWS emission factor of 0.00002 pounds of VOC per 1,000 gallons of throughput. Using this emission factor for the HBEP OWS changes the Table 3.18 OWS VOC emissions to 0.017 pounds for OWS 1 and 0.0022 pounds for OWS 2. The OWS VOC emissions in Appendix F should be revised accordingly.

Response
The original OWS calculations presented by AES in the HBEP application are deemed representative of the VOC emissions from the equipment and a change to the emissions methodology is not warranted at this late stage in the permitting process regardless of what was accepted for Alamitos.

Page 30, Table 3.19 – The auxiliary boiler hours should include a footnote similar to Appendix D,Table D.11 stating “Based on 71 mmBtu/hr. Note that the unit may operate more hours at a lower heat input rate.”

Response
The footnote concerning operating hours of the auxiliary boiler is included for Table 3.4 where the operating profile of the boiler is shown.

Page 33, Table 3.25 – The hourly and annual auxiliary boiler greenhouse gas (GHG) emissions data appear incorrect. Based on the hourly and annual fuel consumption presented in Appendix I, the correct auxiliary boiler GHG data is provided in the table below.

Table 3.25 Auxiliary Boiler GHG Emissions

GHG	Emissions	
	Lbs/hr	Tons/yr
CO2	8306.8	11065.3
CH4	0.16	0.2
N2O	0.02	0.02
Total Mass	8307.0	11065.5
CO2e	8315.4	11076.7

Based on the revised Table 3.25, Appendix I, Table I.13 should also be revised.

Response
The correction has been made to address this comment.

Page 42, Table 4.8 – Table 4.8 indicates that best available control technology (BACT) for VOC emissions is not required for the auxiliary boiler. However, Table 4.15 (Page 52) notes that VOC BACT for the auxiliary boiler is “Combustion Design”. For consistency, SCAQMD should consider including “Combustion Design” for the auxiliary boiler BACT in Table 4.8.

Response
The tables are different. Table 4.8 specifies what type of BACT is required for the boiler, Table 4.15 specifies what BACT technologies were evaluated.

Page 43, Table 4.9 – Table 4.9 indicates that BACT for VOC emissions is not proposed for the auxiliary boiler. However, the Project Owner has proposed the use of clean burning natural gas and good combustion design to control VOC emissions from the auxiliary boiler. Therefore, SCAQMD should consider including “Combustion Design” for the auxiliary boiler BACT in Table 4.9.

Response

Technically BACT is defined as an emission limit. Good combustion design is not an emission limit nor is it a control technology which would be specified in the permit, therefore it doesn't need to be shown in Table 4.9.

Pages 47 and 48, Rule 1304.1 – The Crep values listed at the bottom of Page 47 do not match the calculated value shown at the top of Page 48. The C2yr value used in the fee calculations does not reflect the existing units' megawatt-hours (MWh), as calculated in Appendix Q. The correct C2yr value is 909,616 MWh. The corrected calculations are below:

FPM10 = [(997 × 100/895.5) + 3,986 × (895.5 - 100)/895.5] × 1.0 × 731 × [(4,584,980 – 909,616)/4,584,980] = $2,140,116

FVOC = [(47 × 100/895.5) + 185 x (895.5 - 100)/895.5] × 1.2 × 639 × [(4,584,980 - 909,616)/4,584,980] = $104,242

Total Fee = $2,140,116 + $104,242 = $2,244,358

Response
Corrections were made to the calculation based on more recent data now included in Appendix Q. Also note that the C2yr is defined as the MWh generation for the previous 24 months immediately prior to permit issuance. The calculations shown the PDOC are only an estimate. The actual value cannot be determined until the time when the permit will be issued.

Page 55, 1st Paragraph – The annual PM10 Class I impact of 0.32 µg/m3 is incorrect; the correct value is 0.006 µg/m3 (refer to the memo from Ian MacMillan to Andrew Lee dated May 18, 2016).

Response
The correction has been made to address this comment.

Page 63, Thermal Efficiency – The HBEP heat rates and GHG performance presented in the table need to be updated. The combined-cycle and simple-cycle heat rates are 6,774 British thermal units per kilowatt-hour (btu/kWh) and 8,907 btu/kWh, respectively, based on Appendix I, Tables I.7 and I.11. The GHG performance should be 0.381 metric tons carbon dioxide per megawatt-hour (MtCO2/MWh), based on the emissions presented in Appendix I, Tables I.5, I.10, and I.13, corrected per the above comments. The footnote for this table should also be updated to reference Appendix I.

Response
The table on page 63 does not correspond to the information in the Appendix I tables I.7 and I.11. The Appendix I tables show heat rates at specific loads. The footnote on page 63 states "*Heat rates*

averaged over the operating range of 50-100% load. GHG performance based on plant-wide CO2 emissions of 1,781,868 metric tons per year. Furthermore, the data on page 63 of the PDOC was provided by AES on page 3-21 of their application submittal.

Page 64, Step 5 – Select BACT, 4th Paragraph – The SCTG GHG emission rate of 1,359 lb CO_2/net MWh should be 1,378 lb CO_2/net MWh, consistent with Appendix I.

Response
The correction has been made to address this comment.

Page 64, Step 5 – Select BACT, 5th Paragraph – The CCTG emission limit of 870,251 tons CO_2 per year should be 873,035, consistent with Table 3.23. The SCTG emission limit of 103,578 tons CO_2 per year should be 103,576, consistent with Table 3.24.

Response
The correction has been made to address this comment.

Page 69, VOC, Requirements Bullet – The reference to Condition D12.7 should be Condition D12.10 and the minimum oxidation catalyst temperature should be 570 degrees Fahrenheit (°F), consistent with Table 2.4.

Response
The correction has been made to address this comment.

Pages 109 and 110, Table A.2, 1st Row – The ambient conditions shown on the first row are slightly different.

Response
The correction has been made to address this comment.

Page 110, Table A.2 – The Stack Exhaust Flow units are shown as dscfm but are shown as 103 acfm on the previous page.

Response
The correction has been made to address this comment.

Page 114, Table A.9 – The daily CCTG emissions incorporate a 1 hour downtime in the calculations. AES suggests increasing the normal operating hours per day to 21.5 hours.

Response
The daily maximum emissions calculations are only performed for informational purposes. Daily emissions are not used in any permit condition or limit. The assumption of a 1 hour down time is included in the calculation to more realistically estimate the emissions, as typically there will be down time after a shutdown before a subsequent start up.

Page 115, Table A.10 – The daily CCTG emissions incorporate a 1 hour downtime in the calculations. AES suggests increasing the normal operating hours per day to 21.5 hours.

Response
The maximum daily emissions calculations are only performed for informational purposes. Daily emissions are not used in any permit condition or limit. The assumption of a 1 hour down time is included in the calculation to more realistically estimate the emissions, as typically there will be down time after a shutdown before a subsequent start up.

Page 115, Table A.11 – Update Table A.11 to reflect the elimination of the 1 hour downtime assumption, based on changes recommended for Tables A.9 and A.10.

Response
The maximum daily emissions calculations are only performed for informational purposes. Daily emissions are not used in any permit condition or limit. The assumption of a 1 hour down time is included in the calculation to more realistically estimate the emissions, as typically there will be down time after a shutdown before a subsequent start up.

Page 117, Table A.18 – The table footnote needs to be revised as follows:

SOx for annual emissions is based on 0.25 gr/100 scf:

0.25 grains/100 scf fuel converts to SOx per mmcf fuel as follows: 0.25 grains/ 100 scf(lb/7000 grains)(64 lbs/lb-mole SO2/32 lbs/lb-mole S)(1E6 cf/mmcf) = 0.71 lbs SO2/mmcf fuel.

Response
The correction has been made to address this comment.

Pages 120 and 121, Table B.2, 1st Row – The ambient conditions shown on the first row are slightly different.

Response The correction has been made to address this comment.

Page 121, Table B.2, Simple Cycle Gas Turbine Hourly Emissions, PM10 – The 110 °F hourly particulate matter (PM) emission rate should be 6.24 pounds per hour (lb/hr) instead of 5.92 lb/hr.

Response The 5.92 lbs/hr PM10 emission rate for this operating scenario was provided by AES in their permit application Appendix A Table 7 (December 2015.

Page 122, Table B.3, Sample Calculation – The sample calculation shown for oxides of sulfur (SOx) is incorrect as the italics equation should result in a value of 2.14 lbs SO2/MMcf fuel, not 2.02.

Response The correction has been made to address this comment.

Page 124, Table B.8, Downtime Row – The daily SCTG emissions incorporate a 1 hour downtime. AES suggests increasing the normal operating hours per day to 22.57 hours.

Response The maximum daily emissions calculations are only performed for informational purposes. Daily emissions are not used in any permit condition or limit. The assumption of a 1 hour down time is included in the calculation to more realistically estimate the emissions, as typically there will be down time after a shutdown before a subsequent start up.

Page 124, Table B.9, Downtime Row – The daily SCTG emissions incorporate a 1 hour downtime. AES suggests increasing the normal operating hours per day to 22.57 hours.

Response The maximum daily emissions calculations are only performed for informational purposes. Daily emissions are not used in any permit condition or limit. The assumption of a 1 hour down time is included in the calculation to more realistically estimate the emissions, as typically there will be down time after a shutdown before a subsequent start up.

Page 125, Table B.10 – Update Table B.10 to reflect the elimination of the 1 hour downtime assumption, based on changes recommended for Tables B.8 and B.9.

Response The maximum daily emissions calculations are only performed for informational purposes. Daily emissions are not used in any permit condition or limit. The assumption of a 1 hour down time is included in the calculation to more realistically estimate the emissions, as typically there will be down time after a shutdown before a subsequent start up.

Page 129, Table C.1, Fuel Use Columns – The reported fuel use for each activity is inconsistent with AES's March 16, 2016 permit application Appendix A, Table 1, assuming a heat content of 1,050 million British thermal units per million standard cubic feet (MMBtu/MMscf). Please revise the fuel use accordingly (see revised table in Attachment 1). This change will need to be reflected in the commissioning emission rate presented in Condition A63.6.

Response The corrections have been made to address this comment.

Page 129, Table C.1, Verify STG on Turning Gear, Combined Blows, Finalize Bypass Valve Tuning Row, NOx emissions – The correct total NOx emissions for this activity is 2,328 pounds, not 2,338.

Response The correction has been made to address this comment.

Page 131, Table C.3, Fuel Use Columns – The reported fuel use for each activity is inconsistent with AES's March 16, 2016 permit application Appendix A, Table 2, assuming a heat content of 1,050 MMBtu/MMscf. Please revise the fuel use accordingly (see revised table in Attachment 1). This change will need to be reflected in the commissioning emission rate presented in Condition A63.9.

Response The corrections have been made to address this comment.

Page 146, Appendix F – As noted in the comments on Table 3.18, the SCAQMD accepted an OWS emission factor of 0.00002 pounds of VOC per 1,000 gallons of throughput in the Alamitos Energy Center permit application. Using this emission factor for the HBEP OWS results in OWS VOC emissions of 0.017 pounds for OWS 1 and 0.0022 pounds for OWS 2.

Response The original OWS calculations presented by AES in the HBEP application are deemed representative of the VOC emissions from the equipment and a change to the emissions methodology is not warranted at this late stage in the permitting process regardless of what was accepted for Alamitos.

Page 164, Table H.19A – Acute maximally exposed individual worker (MEIW) and sensitive receptor values are incorrect. The correct acute MEIW value is 0.032. The correct acute sensitive receptor value is 0.0091.

Response The corrections have been made to address this comment.

Page 164, Table H.19C – The MEIW cancer risk is incorrect. The correct MEIW cancer risk is 0.005 in one million.

Response The correction was not made. The MEIW for the AB is reported as 0.004 in a million according to the 5/18/16 memo from Ian MacMillan.

Page 183, Table O.3, HBEP CO2e PTE – The reported HBEP carbon dioxide equivalent (CO2e) potential to emit (PTE) of 1,965,939 tons does not match the value shown in Table O.2 of 1,966,317.

Response The correction has been made to address this comment.

Page 195, Appendix T, Review of Criteria Pollutant BACT Levels for Recent Projects – For completeness, AES suggests including the SCAQMD's BACT determinations for sulfur dioxide (SO2)and PM, consistent with the discussions on PDOC Pages 41-43 and 50-53.

Response Thank you for the suggestion. We didn't deem it necessary to show PM10 and SOx BACT determinations in Appendix T, since Appendix T is a listing of BACT levels only.