Statement of Basis
Proposed Significant Permit Revision

Owner/Operator:	AES Huntington Beach 21730 Newland St Huntington Beach, CA 92646
Facility ID:	115389
SIC Code:	4931
Equipment Location:	21730 Newland St Huntington Beach, CA 92646
Title V Revision Appl No.:	633201
Application Submittal Date:	December 15, 2021
Responsible Official:	Weikko Wirta Plant Manager (714) 374-1421

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1.0 INTRODUCTION, SCOPE OF PERMIT, HISTORY AND RECOMMENDATION

Title V is a national operating permit program for air pollution sources established under the Clean Air Act. Facilities subject to Title V must obtain a Title V permit and comply with specific Title V procedures to modify the permit. Title V facilities are required to certify compliance with their permit on an annual basis. The intent of the program is to provide a comprehensive permit document with a clearer determination of applicable requirements, to enhance the enforceability of a source's air quality obligations, as well as to allow greater opportunity for public participation and public access to enforcement actions and facility emissions information.

The AES Huntington Beach facility is subject to Title V requirements because its potential to emit (PTE) of NOx, CO, and VOC emissions are greater than the major source thresholds (see Appendix F). Additionally, the turbines at this facility are defined as affected units under the Acid Rain provisions, making this facility an affected source [40CFR Part 72, §72.6(a)(3)]. The facility is not a major source of HAPs (see Appendix F).

Facility Description and History

The Huntington Beach Generating Station is located 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 nearest inhabitants are located in a residential area approximately 300-400 feet from the site. The closest school is Edison High School located approximately 0.6 miles north-east of the site.

The facility was originally constructed, owned and operated by Southern California Edison (SCE) in the late 1950's, and consisted of 4 utility boiler/steam turbine generators, Boilers 1-4. In 1967 a set of eight (8) Pratt & Whitney peaking turbine engines were added to the site. Total plant capacity at that time was about 1013 MWs. In 1998 the plant was sold to AES Southland as California was undergoing a restructuring in the electric power industry and SCE sold most of its generating stations throughout the state. Boilers 3 and 4 have been taken out of service and were permanently retired in 2011. The generators associated with Boilers 3 and 4 have been converted into synchronous condensers to provide voltage support and stability for the grid. The Pratt & Whitney turbines were shutdown in 2002 and were recently removed from the site. Boiler 1 has been permanently retired. It's last day of availability for operation was December 31, 2019. Steps were taken to render the unit inoperable in early January 2020 (see Appendix G). Boiler 2 is still operational.

The primary function of the facility is to provide power to the California electrical grid.

The plant currently consists of Boiler 2 and two combined cycle turbines, along with an auxiliary boiler, a liquid urea storage tank, an aqueous ammonia storage tank, and 2 diesel fueled emergency fire pump engines.

Boiler 2 is natural gas fired, with the ability to fire some field gas from offshore platforms. It is rated at 2021 mmbtu/hr heat input and 215 MW power output. Boiler 2 is a once through cooling (OTC) unit that was originally scheduled to be retired at the end of 2020 as required by the State Water Resource Control Board. However, in 2020, the SWRCB voted to postpone the retirement of this unit for 3 years until 12/31/2023 to ensure overall system wide grid stability.

The combined cycle turbine plant (referred to as the Huntington Beach Energy Project, or HBEP) consists of two GE 7FA turbines, each rated at 2,273 mmbtu/hr input and 232.1 MW (nominal gross) output, each with an unfired HRSG, which provide steam to one common steam turbine (2X1 configuration), rated at 229.7 MW (nominal gross). Both turbines are controlled with DLN combustors, as well as post combustion control in the form of SCRs and Oxidation Catalysts. The turbines are designed for fast start capability. The turbines each vent to a 150 foot tall stack.

The auxiliary boiler is used to provide steam to both assist the combined cycle plant in reaching its base load quickly, and to reduce the start up time. It is rated at 71 mmbtu/hr. The boiler is controlled with a Low NOx burner using flue gas recirculation, and post combustion control in the form of an SCR.

The two 275 hp diesel-fueled emergency engines are Tier 1 engines. They are turbocharged and aftercooled, but have no post combustion control.

The 30,000 gallon urea storage tank serves the SCR system for Boiler 2. Urea is delivered to the facility in the form of dry pellets and stored on site. The dry urea is then dissolved in water and converted to ammonia prior to injection into the boiler exhaust with the use of a urea-to-ammonia converter. The 22,290 gallon aqueous ammonia storage tank serves the SCR system for the combined cycle turbines. It is a horizontal pressure tank.

Summary of Permitted Equipment

Equipment Description
Boiler No. 2, natural gas fired, process gas fired, 215 MW with SCR
Internal Combustion Engine, emergency fire water pump, diesel fuel, 275 hp
Internal Combustion Engine, emergency fire water pump, diesel fuel, 275 hp
Storage Tank, liquid urea, 30,000 gallons
Urea to Ammonia Conversion Reactor
Turbine No. 1, natural gas fired, combined cycle, 236.1 MW, with DLN, SCR, and oxidation catalyst
Turbine No. 2, natural gas fired, combined cycle, 236.1 MW, with DLN, SCR, and oxidation catalyst
Storage Tank, 19% aqueous ammonia, pressure vessel 22,290 gallons
Auxiliary Boiler, natural gas fired, 71 mmbtu/hr, with Low NOx burner, FGR, and SCR
Oil/water separator

Equipment on site that is exempt from permitting includes air conditioning units, abrasive blasting equipment, portable coating equipment, oil water separators, pressure washers, diesel sump pump, portable gasoline powered generator, heated cleaning equipment, and a welding machine.

Some of this equipment is required to be registered with South Coast AQMD.

AES submitted these Class I applications on December 15, 2021 to request an increase in the permitted annual hours of operation for the combined cycle turbines. Additionally, after application submittal, AES further requested that their permit include a Plantwide Applicability Limit (PAL) for PM2.5. The requested changes are discussed in more detail in Section 3.0.

The following table summarizes the application submittal.

A/N	Equipment	BCAT	Fee Schedule	Fee
633199	Combined Cycle Turbine No. 1	013709	G	$23,684.83
633200	Combined Cycle Turbine No. 2	013709	G (identical)	11,842.42
633201	Title V Revision	555009	////////////	2,853.99
			Expedite Fee	17,763.63
			Total Fee	$56,144.87

Amount submitted: $56,144.87 (check # 101380, tracking # 157330)

RECOMMENDATION

After the end of the 45 day EPA review and 30 day public notice period, pending any comments received, issue a revised Permit to Operate subject to the conditions listed in Section 7.0.

2.0 EQUIPMENT DESCRIPTION, CONSTRUCTION AND PERMITTING HISTORY

Section D of the Facility Permit ID# 115389

Proposed changes or additions are shown in **bold/underline**, proposed deletions are shown in ~~strikethrough~~

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: ~~618931~~ **633199** 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**: 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: 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] **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]	A63.7, A195.6, A195.7, A195.8 A195.9, A327.1, B61.1, C1.7, C1.8, C1.9, D29.6, D29.7, D82.3 D82.4, E57.2, E193.4, E193.6, E448.1, I297.1, I298.1, K67.5
STACK SERVING UNIT NO. 1, 150' H. X 20' DIA.	S123	D115			

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
A/N: ~~618931~~ **633199**					
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: ~~618932~~ **633200** GENERATOR, 236.1 MW GROSS AT 32 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NO. 1, 221.4 MW GROSS AT 32 DEGREES F	D124 (B125) (B126) (B127)	C129 C130 S132	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO**: 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: 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] **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]	A63.7, A195.6, A195.7, A195.8 A195.9, A327.1, B61.1, C1.7, C1.8, C1.9, D29.6, D29.7, D82.3 D82.4, E57.2, E193.4, E193.6, E448.1, I297.4, I298.4, K67.5
STACK SERVING UNIT NO. 2, 150' H. X 20' DIA. A/N: ~~618932~~ **633200**	S132	D124			

South Coast AQMD Permits to Construct for the combined cycle turbines, the auxiliary boiler, and the aqueous ammonia tank were issued on April 18, 2017, along with the CEC license for the project. Construction on the repower project began on August 1, 2017. First fire of the turbines (the start of commissioning) was on October 4, 2019 (unit 1) and October 6, 2019 (Unit 2). The units began commercial operation in January 2020.

There was a modification in 2019 to correct the PM10 monthly emission limit and add a daily start up limit and a modification in 2020 to adjust the definition of a start up, and to increase the allowable NOx emissions during a non-cold start. A final Permit to Operate for the turbines, which incorporated all the previous turbine modifications, along with the ammonia tank and auxiliary boiler, was issued on April 12, 2022

The combined cycle turbines were installed as a repower project to replace utility Boiler 1 at HBGS and utility Boiler 7 at AES's Redondo Beach Generating Station. The initial project scope also included the installation of two simple cycle GE LMS100 turbines and Permits to Construct for the simple cycle turbines were issued on April 18, 2017. However, the simple cycle turbines were never constructed. On September 21, 2021, AES notified South Coast AQMD that the project was cancelled and relinquished the permits for these units.

The following table shows the application history:

Equipment	Appl. No	Description	P/C Issue Date
CCGT #1	578073	Initial application	8/18/17
	613959	Modification to add a daily start up limit	10/14/19
	618931	Modification to clarify start up definition and increase the allowable NOx emissions during a non-cold start	4/21/20
CCGT #2	578074	Initial application	8/18/17
	613961	Modification to add a daily start up limit	10/14/19
	618932	Modification to clarify start up definition and increase the allowable NOx emissions during a non-cold start	4/21/20

The AES Huntington Beach facility is subject to both NOx and SOx RECLAIM. It is a major PSD source for criteria pollutants, and an area source of HAP emissions. The proposed modification will be evaluated as significant revision to the existing Title V permit, and a major modification under the PSD regulation. The project is also subject to the California Energy Commission (CEC) licensing procedure and an Petition to Amend (PTA) to modify the license to account for the proposed change has been submitted with that agency (05-AFC-02).

3.0 PROCESS DESCRIPTION

The two GE7FA.05 combined cycle turbines are arranged in a ‘two-on-one’ (2X1) configuration. Each turbine is rated at 2,273 mmbtu/hr heat input (maximum at low temperature conditions), and 232.1 MW output (nominal gross). Fuel use at these conditions is approximately 2.16 mmcf/hr, based on a natural gas heat content of 1050 btu/cf. Emissions are controlled with dry low NOx combustors, SCR, and oxidation catalysts. Each unit has an unfired heat recovery steam generator (HRSG) providing steam to one 229.7 MW (nominal gross) 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 is 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 catalysts are contained within the HRSG.

Each combined cycle turbine is vented to a stack 150 feet tall. The turbines are equipped with inlet air filters, inlet air compressors, and evaporative coolers. Incoming combustion gas passes through the facility's compression station and are brought to a pressure of approximately 600 psi prior to combustion.

Turbines specs are summarized in the following table:

Combined Cycle Turbine Data

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

Turbine Stack Data

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

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Currently the turbine permit limits the hours of operation for each unit to 6640 hours in any calendar year as specified in condition C1.9. This hourly operational limit includes the time the unit is undergoing a start up or shutdown. AES presented this operational scenario in the initial permit application based on the anticipated capacity factor of the units. However, it should also be noted that at the time of initial permitting, AES was also proposing to construct 2 simple cycle turbines at Huntington Beach Generating Station, each with an expected capacity factor of about 24% (2100 hours of operation). The simple cycle turbine plant was never constructed and the permits for these units were surrendered by AES in 2021.

There are other permit limitations on the turbine operation as well. Operational limits are summarized in the following table:

	Operational Limit
Overall Starts	2 per day
Cold Start	15 per month, 80 per year,
Non-cold Start	47 per month, 420 per year
Shutdown	62 per month, 500 per year
Power Output	693.8 MW total gross output from entire combined cycle plant
Total Operation	6400 hours per year inclusive of SU/SD

The facility reported the following hours of operation in 2021

Unit	Month	2021 Hours
CT1	Jan	626.04
	Feb	401.41
	Mar	583.63
	Apr	487.2
	May	488.44
	Jun	494.72
	July	720.82
	Aug	604.69
	Sep	564.53
	Oct	570.65
	Nov	593.74
	Dec	461.49
	Total	6597.36
CT2	Jan	530.08
	Feb	352.98
	Mar	567.96
	Apr	479.53
	May	477.79
	Jun	453.55
	July	711.34
	Aug	601.45
	Sep	570.11
	Oct	583.49
	Nov	611.36
	Dec	602.63
	Total	6542.27

** As reported under the Acid Rain program*

The facility reported the following hours of operation in 2022

Unit	Month	2022 Hours
CT1	Jan	553.4
	Feb	456.53
	Mar	534.53
	Apr	435.39
	May	295.24
	Jun	535.47
	July	614.51
	Aug	700.74
	Sep	638.28
	Oct	649.49
	Nov	471.1
	Dec	694.64
	Total	6539.72
CT2	Jan	567.48
	Feb	428.9
	Mar	539.1
	Apr	321.7
	May	274.41
	Jun	542.81
	Jul	610.92
	Aug	699.25
	Sep	639.59
	Oct	644.02
	Nov	459.22
	Dec	692.16
	Total	6419.56

** As reported under the Acid Rain program*

The request to increase the annual allowable hours of operation will require an analysis of New Source Review and the offset fee rule, Rule 1304.1.

After initial evaluation of the permitting impacts of the additional hours of operation, AES was informed that the proposal would result in an emissions increase for PM2.5 that exceeded the significance threshold of Rule 1325. Since a major modification for PM2.5 under Rule 1325 requires emission offsets, AES explored several options including 1) reduce the impacts to less than significant by reducing the requested hours of operation, and 2) reduce the facility emissions below the major source threshold by accepting a PTE limit on the operation of Boiler 2. The 3rd option considered by AES was requesting a Plantwide Applicability Limit (PAL). In an email dated August 19, 2022, AES indicated that they wished to pursue the PAL. However, AES later changed direction and decided against a PAL, and instead opted for a PTE limit on Boiler 2. AES submitted a separate application on December 19, 2022 (A/N 641791) to request a heat input limit on Boiler 2 which would reduce the unit's annual PTE.

The implications of the additional hours of operation as they pertain to Regulation XIII are discussed in more detail in Section 4.0.

4.0 REGULATORY APPLICABLILITY DETERMINATIONS

RULE 212-Standards for Approving Permits

This rule specifies the types of projects requiring a public notice, the entities to be included in the notice, and the procedures for distribution of the notice. In accordance with the rule, noticing is required for projects with emissions increases located within 1000 feet of a school, projects which result in cancer risks above 1 in a million or 10 in a million, or projects which result in criteria pollutant emissions increases above certain thresholds.

The proposed additional hours of operation for the turbines does not result in an increase in health risk which exceeds 1 per million [212 (c)(3)], The facility performed a Health Risk Assessment, the results of which showed the cancer risk from the additional hours of operation to be 0.68 per million, and the hazard indices < 1.0. The risks were determined for both turbines combined. Reference Appendix H.

The facility is not located within 1000 feet of a school [212 (c)(1)]. The nearest school is Edison High School located at 21400 Magnolia St. in Huntington Beach, approximately 0.6 miles north-east of the site.

The proposed additional hours of operation for the turbines does result in an increase in annual emissions for all pollutants. However, in accordance with the Rule 212 Policy Implementation Guidance document dated 1/31/19, an emissions increase for purposes of Rule 212 applicability is determined as follows:

- Dividing the maximum monthly emissions by 30 whenever the resulting permit will contain a monthly emission limit for the pollutant in question, or

- The maximum daily emissions whenever the resulting permit will not contain a monthly emission limit for the pollutant in question

The permit limits the maximum monthly emissions under condition A63.7. The maximum monthly emissions will not change as a result of the additional 1000 hours of operation because the turbines are currently permitted for maximum monthly operation, ie 740 hours per month.

Therefore, a public notice under Rule 212 is not required for this project.

Note that a public notice is required for this project under Rule 1710 (PSD) and Rule 3006 (Title V).

Also note that prior to issuing the initial permits to construct for the turbines in 2017, a public notice was distributed. The project configuration at that time consisted of the 2 combined cycle turbines, along with the auxiliary boiler, and 2 simple cycle turbines. (note that the emissions from the project did not include the existing boilers at that time, since they were not being modified). The simple cycle turbines were never constructed and the permits for these units were subsequently surrendered.

The public notice distributed in 2017 included the estimated emissions from the new equipment as shown in the following table.

2017 Public Notice Emissions

Pollutant	CCTG 1	CCTG 2	SCTG 1	SCTG 2	Auxiliary Boiler	Total	
	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr	TPY
NOx	119,500	119,500	21,252	21,252	1,313	282,817	141.4
CO	212,260	212,260	29,330	29,330	7,522	490,702	245.4
VOC	64,760	64,760	6,076	6,076	1,010	142,682	71.3
PM10/PM2.5	56,440	56,440	12,485	12,485	1392	137,850	68.9
SOx	9,960	9,960	1,201	1,201	382	22,704	11.4
NH3	94,550	94,550	10,500	10,500	412	210,512	105.3

CCTG at 6400 hours per year, 17 lbs/ non cold start

For comparison , the proposed modification to add 1000 hours/yr per turbine results in a new annual PTE shown in the following table.

Combined Cycle Plant PTE, with Increased Hours

Pollutant	CCTG 1	CCTG 2	Auxiliary Boiler	Total	
	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr	TPY
NOx	142,600	142,600	1,313	286,513	143.3
CO	204,355	204,355	7,522	416,232	208.1
VOC	70,560	70,560	1,010	142,130	71.1
PM10/PM2.5	64,940	64,940	1,392	129,880	64.9
SOx	11,460	11,460	382	23,302	11.7
NH3	110,050	110,050	412	220,512	110.3

CCTG at 7400 hours per year

RULE 218/Rule 218.1 – Continuous Emission Monitoring

These rules apply to CEMS which are not subject to RECLAIM. In order to insure the turbine's meet the CO BACT limit as specified in the permit, a CO CEMS is required by permit condition. The rule requires submittal of an "Application for CEMS" for approval. AES has submitted the required CEMS application and South Coast AQMD Source Test Engineering has granted approval for the CEMS. The CO CEMS was installed within the timelines specified in the permit. The rule requires that the CEMS data is recorded and records of the data is 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.

RULE 218.2/Rule 218.3 – Continuous Emission Monitoring: General Provisions
These rules will become the applicable CEMS specification rules for CEMS that are currently subject to Rules 218 and 218.1, at any time that an application for a CEMS recertification is submitted after 1/1/22, but no later than 1/1/25. These rules will also supersede the RECLAIM CEMS requirements no later than 24 months after the facility exits RECLAIM.

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 combined cycle turbines. AES had problems with visible emissions during the commissioning of the turbines and was issued violation notices. There has not been any reported visible emissions or citizen complaints of visible emissions since the end of December 2019. It is not expected that the increase in allowable NOx during a non-cold start will result in visible emissions. Data submitted by AES during start up shows that the NOx concentrations peak at about 80-90 ppm (see Appendix B). At those concentrations, NOx is not likely to cause visible emissions.

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 potential for nuisance issues during normal operation of the combined cycle turbines is expected to be low. AES had problems with citizen complaints of smoke, odors, dust, and other complaints during the commissioning of the turbines. There has not been any reported citizen complaints since the end of December 2019.

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 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 1.5 ppmvd at 15% 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

Grain Loading = 8.5 lbs/hr x [(7000 grains/lb) x (12/4.29)]

70.1E+06 scf/hr

= 0.002 grains/scf

Compliance has been verified through the initial source testing, summarized as follows:

Turbine 1, 100% load condition, test date January 16, 2020

PM	=	6.83 lbs/hr
Exhaust rate	=	855,579 dscfm
CO2	=	4.42 %
Grain loading	=	0.0025 gr/scf @ 12% CO2

Turbine 2, 75% load condition, test date January 15, 2020

PM	=	4.08 lbs/hr
Exhaust rate	=	686,623 dscfm
CO2	=	4.51 %
Grain loading	=	0.0018 gr/scf @ 12% CO2

Ongoing compliance will be verified through the once-per-3 year testing.

Rule 429.2 – NOx Start up and Shutdown Exemption for Electricity Generating Units

This rule provides an exemption from the NOx emission limits in Rule 1135 during scheduled start ups and shutdowns. The number of scheduled start ups is limited to 12 per year (no fuel oil readiness testing), and the duration of the start up and shutdown events is limited based on the type of unit, and whether the unit is existing (installed on or before 1/7/22), or new (installed after 1/7/22). The rule requires a temperature gauge in the exhaust prior to the SCR, and also requires that ammonia injection commences once the exhaust temperature has reached the minimum temperature for proper SCR operation. The rule requirements take effect on 1/1/24. The HBEP turbines are subject to a permit condition which limits the duration of the start up and shutdown, and the limits in the permit meet the rule requirement for an existing combined cycle unit. Additionally, the permit requires a temperature gauge in the exhaust prior to the SCR catalyst, and requires ammonia injection to begin once the temperature in the exhaust meets the minimum operating temperature of the SCR catalyst. Therefore, the facility does not need to take any further action to comply with this rule once it has exited RECLAIM.

RULE 431.1 – Sulfur Content of Gaseous Fuels

The facility is not a supplier of natural gas, it is an end user. It is therefore not subject to the 16 ppm sulfur limit. Additionally, the facility is in SOx RECLAIM. Therefore, any applicable end user limits in this rule would not apply. As a side note, the natural gas combusted in the turbines is pipeline quality supplied by the utility and meets the sulfur limit of this rule.

In accordance with paragraph (e)(3), an electric utility generating facility is required to maintain a continuous fuel gas monitoring system (CFGMS) to determine the sulfur content of the fuel, and submit monthly reports indicating the amount of gas combusted, the 4 hour average sulfur content of the gas, and the total SOx emissions. The facility maintains the fuel gas sulfur monitoring equipment and provides the monthly reports as required.

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 (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

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

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

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

Compliance has been verified through the initial source testing, summarized as follows:

Turbine 1, 100% load condition, test date January 16, 2020

PM	=	6.83 lbs/hr
Exhaust rate	=	855,579 dscfm
O2	=	13.24 %
Grain loading	=	0.0022 gr/scf @ 3% O2

Turbine 2, 75% load condition, test date January 15, 2020

PM	=	4.51 lbs/hr
Exhaust rate	=	702,548 dscfm
O2	=	13.08 %

Grain loading = 0.0012 gr/scf @ 3% O2

Ongoing compliance will be verified through the once-per-3 year testing.

RULE 1135 – Emissions of NOx from Electric Power Generating Systems

This rule is applicable to boilers and turbines (except cogen units) at investor owned, or publicly owned electric utilities, or at facilities with > 50 MW capacity, as well as the power generating engines on Catalina Island. The rule sets the NOx limit to 2 ppm for combined cycle turbines, 2.5 ppm to simple cycle turbines, and 5 ppm for utility boilers. The limits are all based on a 60 minute rolling average, however, the current averaging time in the permits for existing facilities can be kept if there is no equipment modification. There is an exemption from the limits for low use units that are existing units prior to the rule adoption date, and also for Once Through Cooling Units that are retired on or before 12/31/29. The rule requires record keeping for the time and duration of each start up and shutdown, total hours of operation, fuel consumption, and gross and net MWh of electricity produced. The rule also requires ammonia testing for units with SCR. The rule requirements apply to both RECLAIM and non RECLAIM facilities. For RECLAIM facilities, this rule is a RECLAIM "landing rule" and the limits become effective once a facility has exited the RECLAIM program, or by no later than 1/1/24. For non RECLAIM facilities, the rule limits apply by no later than 1/1/24.

The AES turbine permit currently limits the NOx to 2 ppm @15% O2 based on a 60 minute average and NH3 slip is limited to 5 ppm @ 15% O2 based on a 60 minute average. The record keeping requirements and the annual ammonia slip testing requirements are specified in the permit conditions. Therefore, the facility does not need to take any further action to comply with this rule for the turbines once it has exited RECLAIM.

REGULATION XIII/Rule 2005 – New Source Review

New Source Review applies to new or modified equipment which causes an increase in criteria pollutant emissions. Requirements include the use of Best Available Control Technology (BACT), offsets, and modeling.

In accordance with Rule 1306, emission increases are calculated on a 30 day average basis for determination of offsets, and on a maximum daily basis for determination of BACT and modeling requirements.

In accordance with Rule 2005, an emission increase is defined as an increase in a source's maximum hourly potential to emit pre modification vs post modification. Any increase is subject to BACT, modeling and offsets (RTCs). The amount of the increase is calculated on an annual basis for determination of the RTC holding requirements.

The proposal to add 1000 hours of allowable annual operating time for each turbine results in an increase in the annual PTE for all criteria pollutants, as well as NH3. The proposal does not result in an increase in hourly, daily, or monthly 30 day average emissions. This is because 1) the turbines are currently permitted for 24 hours per day operation (ie, there is no limit on daily operation), 2) the turbines are permitted for maximum monthly operation (ie, assuming 744 hours per month operation), and 3) there is no change to the hourly emission rate for any operational mode (start up, shutdown, or normal operation).

Regulation XIII
BACT, Modeling, and Offsets
Because there is no increase in daily maximum or monthly 30 day average emissions, BACT, modeling, and offsets are not required for the Regulation XIII pollutants CO, VOC, and PM10. Note that BACT is required under the PSD regulation, and modeling was performed to determine the impacts from the annual emissions increase of PM10 under PSD as well. Refer to Appendix H and the PSD evaluation. Also note that an offset exemption fee under Rule 1304.1 will be required. Reference Appendix I and the Rule 1304.1 discussion.

Rule 2005
BACT, Modeling and Offsets
Because there is no increase in the maximum hourly emissions, BACT and modeling are not required for the RECLAIM pollutants NOx and SOx. However, offsets in the form of an RTC holding will be required and are based on the additional 1000 hours of operation. The RTC holdings are calculated in Appendix D. Note that BACT is required under the PSD regulation, and modeling was performed to determine the impacts from the annual emissions increase of NOx under PSD as well. Refer to Appendix H and the PSD evaluation.

NOx Holding (1^{st} year only)

16,800 lbs/yr per turbine, 33,600 lbs/yr total

SOx Holding (1^{st} year plus subsequent years)

11,460 lbs/yr per turbine, 22,920 lbs/yr total

Major Polluting Facility

The AES Huntington Beach facility is defined as an existing major source for NOx, CO, and VOC, but not for PM10, or SOx.

Additional Requirements for Major Modification at a Major Polluting Facility

- Alternative Analysis
- Statewide Compliance
- Protection of Visibility

Major Modification defined in Rule 1302
(1) an increase of one pound per day or more, of the facility's potential to emit oxides of nitrogen (NOX) or volatile organic compounds (VOCs), provided the facility is located in the South Coast Air Basin or the Riverside County portion of the Salton Sea Air Basin, or
(2) an increase of 40 tons per year or more, of the facility's potential to emit oxides of sulfur (SOX), or
(3) an increase of 15 tons per year or more, of the facility's potential to emit particulate matter with an aerodynamic diameter of less than or equal to a nominal ten microns (PM10); or,
(4) an increase of 50 tons per year or more, of the facility's potential to emit carbon monoxide (CO).

The increases are determined on a pre modification PTE vs post modification PTE basis.

Pollutant	Regulation XIII Major Source Threshold, tpy PTE	Facility Existing Major Source?	Major Modification Threshold	Proposed Modification Major?
NOx	10	Y	1 lb/day	N
CO	100	Y	50 tpy	N
VOC	10	Y	1 lb/day	N
PM10	100	**N**	**15 tpy**	**N**
SOx	100	N	40	N

Therefore, the project is not considered a major modification under the Regulation XIII definition. Note that the maximum lbs/day of NOx emissions are not increasing as a result of the additional 1000 hours of annual operating time, when comparing the maximum daily PTE pre and post project. This is because the equipment is currently permitted at maximum daily conditions, ie 24 hour per day at full load, with up to 2 start ups per day

//NSR History//
Under the initial Permits to Construct for the combined cycle turbines (A/N's 578073 and 578074), emissions of VOC and PM10 were exempt from offsets under Rule 1304(a)(2) Electric Utility Steam Boiler Replacement. Under Rule 1304.1, the facility was required to pay a fee for the exemption of these pollutants. Emissions of CO were not required to be offset because CO is an attainment pollutant. Emissions of NOx and SOx were subject to RECLAIM, and permit conditions required that the facility hold 147,093 lbs of NOx RTCs for the first year of operation, and 14,083 lbs of SOx RTCs for the first year and each subsequent year of operation. The revision under A/N's 613959 and 613961 did not result in the need for additional offsets. The revision under A/N's 618931 and 618932 resulted in an increase in NOx of 9000 lbs/yr. The total withholding increased to 156,093 lbs/yr. Since the 1st year of operation is over, the withholding requirement for NOx of 156,093 lbs/yr no longer applies. Under this latest application, the additional 1000 hours per year of turbine operation will result in an increase of 33,600 lbs/yr NOx per turbine, and an increase of 8,117 lbs/yr SOx per turbine. The additional NOx amount will need to be withheld for the 1st year after the permit is issued. The additional SOx will be added to the existing SOx withholding requirement of 14,803 lbs/yr per turbine, for a total new withholding requirement of 22,920 lbs/yr per turbine. The withholding requirements are specified in conditions I297.1 and I298.1.

The turbines are subject to BACT limits of 2 ppm NOx, 1.5 ppm CO, and 2 ppm VOC. The revision under A/N 613959 and 613961 did not require a review of BACT or the need for modeling. The revision under A/N's 613959 and 613961 did result in an emission increase in NOx subject to BACT. BACT was determined to be the same as was required under the initial permit. The NOx emission increase was within the emission levels modeled for the initial Permit to Construct, and that modeling was conducted about 3 years prior. Therefore, the modeling performed for the initial Permit to Construct was deemed adequate to demonstrate compliance. BACT and modeling are not required under these latest applications.
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RULE 1304.1 Offset Fee for Power Plants

The rule is applicable to a facility which elects to receive an offset exemption under Rule 1304(a)(2) Boiler Replacement. The rule requires that the facility pay an offset exemption fee. The Rule 13404(a)(2) boiler replacement exemption is used by power plant facilities when they repower their old utility boilers with new gas turbines. The exemption credit is based on the MW rating of the units to be shutdown.

AES Huntington Beach requested the Rule 1304(a)(2) offset exemption for the installation of the new gas turbines and the shutdown of Boilers 1 and 2 at the Huntington Beach Generating Station (HBGS), as well as Boiler 7 at the AES Redondo Beach Generating Station (RBGS) when this project was initially permitted. At that time, AES proposed to install 2 combined cycle turbines and 2 simple cycle turbines, with all 4 turbines to be located at HBGS. The MW capacity of HBGS Boiler 1 and RBGS Boiler 7 were used to offset the MW of the new combined cycle turbines, while the MW capacity of HBGS Boiler 2 was to be used to offset the MW of the new simple cycle turbines. The combined cycle turbines were installed beginning in late 2019. HBGS Boiler 1 and RBGS Boiler 7 were retired accordingly.

The simple cycle turbines were never built and the permit was cancelled by AES. HBGS Boiler 2 remains operational.

The calculation methodology to determine the offset fee required under Rule 1304.1 takes into consideration the annual hours of operation of the new turbines. The initial fee calculation for the AES project used the proposed annual operating limit of 6640 hrs/yr.

AES opted to pay the annual fee under Rule 1304.1 for the first year and continued to pay the annual fee for 2 years after the combined cycle turbines were built. In 2021, AES switched to the single payment option, and a lump sum payment was remitted in late 2021.

The rule does not contemplate a situation where a facility that has finalized its payment under Rule 1304.1 requests an increase to its allowable capacity factor (nor is there any relevant discussion in the staff report). This is a flaw in the rule language. Because Rule 1304.1 allows a facility to request an annual limit on the operation of the new equipment, and because the offset amount is based on the annual operating time limit (represented as Crep in the equation), any future request to increase the allowable annual limit once a 'final payment' has been remitted, presents a problem. [1]

First it needs to be determined if the rule still applies. The purpose of the rule is to require an offset fee for a repower project. In this particular situation, the repower is complete and the facility is now asking for additional hours of operation for the new equipment. The question is whether further modifications to the equipment constitute part of the repower.

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[1] The Rule 1303 basis for requiring offsets is a monthly average PTE. Because the turbines are permitted to allow maximum monthly operation, any increase to the annual operation does not increase the monthly PTE, so a possible alternative of requiring offsets through Rule 1303 is not an option either.

The issue was discussed internally. South Coast AQMD Management has agreed that requiring an additional fee under Rule 1304.1 is appropriate in this situation. AES has indicated that they are willing to provide an additional fee.

The follow up question is then how the calculation methodology for the additional fee should be performed. This issue was discussed internally as well, with the conclusion being as follows:

The calculation of the new amount due will be based on the difference between the single payment fee for 7640 turbine operating hours and the single payment fee for 6640 turbine operating hours. In this case, it was determined that the single payment fee for 6640 operating hours should be calculated using the current offset fee rates, in other words, the amount AES "would have" paid for 6640 hours of operation when taking into account the additional CPI adjustment on 7/1/22. The alternative option - to calculate the new amount due based on the difference between the single payment fee for 7640 turbine operating hours and the previous total amount submitted by AES was deemed inappropriate. This determination was made by SCAQMD legal staff (see memo dated 2/9/23 in the file).

The following table shows the status of the fees paid thus far by AES for this project.

Payment Date	Amount
April 2017(1)	2,479,174
October 2020	1,736,156
October 2021(2)	39,053,168
TOTAL PAID	43,268,498

1 Credited to October 2019 Amount Due
2 Switched to Single Payment Option

Appendix J contains the calculation of the additional fee due for the increased hours of operation.

The total amount due for the additional 1000 hours of operation is <u>$721,895.</u>

The fee shall be remitted prior to the Permit to Construct/Operate being issued. The new annual operating hour limit is reflected in condition C1.9.

RULE 1325– PM2.5 New Source Review

These rules apply to major polluting facilities, major modifications to a major polluting facility, or any modifications 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 70 tons per year of PM2.5, or its precursors – NOx, VOC, SOx, or NH3. A major polluting facility which proposes a modification resulting in a significant increase is required to comply with the following requirements:

- Use of LAER
- Offset PM2.5 emissions at the offset ratio of 1.1:1
- Offset NOx, SOx, and VOC in accordance with RECLAIM or Reg XIII as applicable
- Certification of compliance of emission limits
- Conduct an alternative analysis of the project

As shown in the tables below (reference Appendix F), the existing facility is not a major polluting facility for PM2.5 or SOx, but it is an existing major polluting facility for NOx, VOC, and NH3.

The proposed permit modification is not major source in and of itself for PM2.5 or SOx, and the changes proposed under this application will not result in an emissions increase above the major source threshold (on a PTE vs past actual basis)[2] for VOC or NH3. Note that the determination of the major source status of the Huntington Beach facility reflects the operational limit on the annual heat input for Boiler 2, which was recently proposed by AES under A/N 641791.

The proposed changes do result in an emissions increase above the major source threshold (on a PTE vs past actual basis) for NOx.

Change in Emissions New PTE vs Past Actual, 2 Turbines Combined

Pollutant	Post Modification Annual PTE	Actual Reported Annual Emissions	Change	
	Lbs/yr	Lbs/yr	Lbs/yr	tpy
NOx	285,200	158,064	127,136	63.6
VOC	141,120	68,485	72,635	36.3
PM2.5	129,880	101,440	28,440	14.2
SOx	22,920	18,279	4,641	2.3
NH3	220,100	187,175	32,925	16.5

Actual Emissions are based on 2021 only, not a previous 2 year average. The turbines began operation in early 2020 and operated all of 2020 as a merchant plant. The turbines began operating as a "Power Purchase Tolling Option" in January 1, 2021 under AES' Power Purchase Agreement with SCE , The units capacity factor under the PPS is more representative of the turbine's operational profile going forward.

Pollutant	Rule 1325 Major Source Threshold, tpy PTE	Facility Existing Major Source	Major Modification Threshold, tpy	Proposed Modification Major?
NOx	70	Y	40	Y
VOC	70	Y	40	N
PM2.5	70	N	70	N
SOx	70	N	70	N
NH3	70	Y	40	N

[2] For projects involving new emissions units only, the comparison is PTE to past actual, for projects involving only existing emissions units, the comparison is actual to projected actual. Hybrid tests for projects involving multiple types of emissions units. New emissions units are defined as those constructed after the rule adoption date of 6/3/11.

LAER

LAER is the most stringent emission limitation which has been achieved in practice, or contained in any State Implementation Plan (SIP).

The turbines were subject to BACT/LAER when initially permitted in 2017. At that time a top down BACT analysis was performed. The results of the analysis concluded that BACT/LAER for NOx was the use of Dry Low NOx combustors along with post combustion control in the form of an SCR to reduce the stack NOx emissions to 2.0 ppm at 15% based on a 1 hour average. The projects that were evaluated at that time to make that determination are shown in Appendix M.

Furthermore, under a subsequent permit modification for the turbines evaluated in 2020, an updated BACT analysis was performed specifically for NOx. That analysis is repeated below (refer to A/N 618931).

There have been no other combined cycle gas turbines permitted in South Coast AQMD's jurisdiction since the AES units were permitted.

EPA's RACT/BACT/LAER Clearinghouse was reviewed in March 2020, and it was found that there are no other combined cycle gas turbines permitted since May 2017 with a NOx limit lower than 2.0 ppm. The following table summarizes a few of the combined cycle turbines listed on EPA's website with a NOx limit of 2.0 ppm.

Summary of Recent Combined Cycle Plants Permitted at 2.0 ppm NOx

Facility	Configuration	Turbine Rating, mmbtu/hr	Permit Date
Thomas Township Energy, LLC (MI)	2 turbines each 1X1 with 560 mmbtu/hr duct burner	4200	8/21/19
Renaissance Energy Center (PA)	2 turbines each 1X1 with 914.1 mmbtu/hr duct burner	3580	8/27/18
Shady Hills Energy Center (FL)	1 turbine 1X1 with 210 mmbtu/hr duct burner	3266.9	7/27/18
CPV Three Rivers Energy Center (IL)	2 turbines 2X1	3474	7/30/18
Belle River (MI)	2 turbines 2X1 each with 800 mmbtu/hr duct burner	3658	7/16/18
Palmdale Energy Project (CA)	2 turbines 2X1	2217	4/19/18
Hilltop Energy Center (PA)	1 turbine 1X1 with 981.4 mmbtu/hr duct burner	3509	4/12/17
Killingly Energy Center (CT)	1 turbine 1X1 with 946 mmbtu/hr duct burner	2969	6/30/17

A few facilities shown in the RACT/BACT/LAER Clearinghouse list start up NOx limits.

Facility	Configuration	Turbine Rating, mmbtu/hr	Permit Date	NOx Start Up Limit
New Covert Generating Station (MI)	3 turbines 3X1 each with 256 mmbtu/hr duct burner	2331	7/30/18	249 lbs/hr
Belle River (MI)	2 turbines 2X1 each with 800 mmbtu/hr duct burner	3658	7/16/18	262.4 lbs/hr
Filer City Station (MI)	1 turbine 1X1	1934.7	11/17/17	32 lbs

In conclusion, based on the BACT/LAER analysis performed when the units were initially permitted in 2017, as well as the updated BACT/LAER analysis in 2020, the combined cycle turbines as configured meet the current BACT standard for NOx of 2.0 ppm at 15% O2 on a 1 hour average.

Offsets

In accordance with RECLAIM Rule 2005, the facility will be required to hold 33,600 lbs NOx RTCs for the increase in NOx as a result of the additional 1000 hours of operation. The NOx RTCs must be held by the facility in their RTC account for at least the 1st year of operation after the permit for the increase hours of operation is issued. These requirements are specified in condition I297.1.

The NOx RTCs must be provided prior to the equipment beginning operation with the increased allowable annual operating hours (essentially at the time the Permit to Construct/Operate is issued).

Compliance Certification

AES has provided a written statement dated March 3, 2023, signed by the Responsible Official, certifying that all major sources owned and/or operated by AES in the State of California subject to emission limitation are in compliance with such limitations. A copy of the letter is included in the file for reference.

Alternatives Analysis

AES provided this statement when asked about the possibility of installing a new battery energy storage system instead of increasing the hours of operation of the turbines at the HB Generating Station:

> An additional 1,000 hours of operating time for the Huntington Beach Energy Project (HBEP) combined Cycle facility will bring critically needed generation to the California grid in a very expeditious manner. The expanded capability of the facility will be achieved with the latest combined cycle gas turbine technology, which is a highly efficient, dispatchable generation resource that does not use ocean cooling water, has exceptionally low emission rates, and uses 90% less potable water, which is critical in this era of drought. As this is an existing operating project which requires no physical modifications to achieve the additional capabilities, as soon as

the permit modification is issued, the additional hours will be available to the project, the CAISO and energy agencies.

AES sees the expanded capabilities of this highly efficient, fully dispatchable facility as a key part of the responsible transition to a zero-carbon grid of the future. As the continued buildout of renewable generation technologies takes place over the next decade, facilities like the HBEP will play a critical role in enabling that transition with other responsive technologies like battery storage projects that will be able to respond to the highly dynamic nature of the net peak of the day. Additionally, with California's significant effort in clean fuels technologies such as hydrogen, there is a potential future that could see the facility transition away from 100% natural gas.

Although current interconnection capacity is presently limited due to the identified critical need for additional dispatchable generation from our Huntington Beach OTC Unit 2, we do see a pathway towards the installation of additional Battery Energy Storage Systems (BESS) once that unit is retired, and the 226 MW of capacity becomes available. AES has been an industry leader in this area with three BEES facilities in operation in California totaling 327 MW of capacity with more projects in development. The Alamitos Energy Center in Long Beach currently has a 100 MW BESS in operation with another 82 MW planned for delivery in 2024.

Rule 1401 – Toxic Air Contaminants

This rule applies to new permit units, relocations, and modifications to existing permit units. The rule specifies the limits for maximum individual cancer risk (MICR), cancer burden, and non-cancer acute and chronic hazardous index.

The proposed permit revision to add 1000 hours of annual allowable operating hours results in an increase in the emissions of toxic air contaminants from the turbines. Therefore, a health risk assessment to determine the impacts is required.

Approximate increase for the two turbines combined is about 1,585 lbs/yr formaldehyde and 3530 lbs/yr total toxic emissions. Calculations are shown in Appendix C.

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 I. The results of the model are summarized below:

Model Results – HRA (2 turbines combined, project increase only)

Receptor	Cancer Risk Per Million	Chronic Hazard Index
Residential	0.86	0.000968
Worker	0.02	0.000860
Sensitive receptor	0.59	0.000860

The results show that the cancer risk for the increase in annual operation for the two turbines combined is less than the rule limit of 10 in one million (for permit units with T-BACT, considered an oxidation catalyst for the turbines). Furthermore, the chronic hazard index is less than 1. The acute hazard index was not determined since the annual emissions increase will not cause acute impacts . For reference individual risk for each turbine is shown in Appendix L.

The modeling was reviewed by SCAQMD modeling staff and deemed acceptable. Refer to the modeling review memo in Appendix L.

Rule 1401.1 – Requirements for New or Relocated Facilities Near Schools

The requirements of this rule apply to new or relocated facilities that will be within 1000 feet of a K-12 school with 12 or more children. The definition of school does not include private school in which the education is conducted in private homes. A new facility is defined as one that begins operation on or after 12/4/05. The AES HB facility is not a new facility is accordance with the definition in this rule and furthermore, there is not school within 1000 feet of the facility.

REGULATION XVII – Prevention of Significant Deterioration

The South Coast Basin where the project is 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 cycle gas turbine power plant, the AES HB facility 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 AES HB facility is defined as a major source for NO2, CO, and PM10, because the emissions of those pollutants are greater than 100 tpy (see Appendix E). With the addition of 1000 hours of annual operating time, there is a significant increase of NO2 and CO, but not PM10, and therefore, a PSD analysis is required for NO2 and CO.

In accordance with Rule 1706(c), the post modification emissions from a modified permit unit are determined based on PTE, and the pre modification emissions are based on the actual emissions averaged over a 2 year period.

Change in Emissions New PTE vs Past Actual
2 Turbines Combined

Pollutant	Post Modification Annual PTE	Actual Reported Annual Emissions	Change	
	Lbs/yr	Lbs/yr	Lbs/yr	tpy
NOx	285,200	158,064	127,136	63.6
CO	408,710	30,728	377,982	189.0
PM10	129,880	101,440	28,440	14.2
SOx	22,920	18,279	4,641	2.3

Actual Emissions are based on 2021 only, not a previous 2 year average. The turbines began operation in early 2020 and operated all of 2020 as a merchant plant. The turbines began operating as a "Power Purchase Tolling Option" in January 1, 2021 under AES' Power Purchase Agreement with SCE , The units capacity factor under the PPS is more representative of the turbine's operational profile going forward.

Pollutant	PSD Major Source Threshold for AES HB, tpy PTE	Facility Existing Major Source	PSD Major Modification Threshold fir AES HB, tpy	Proposed Modification Major?
NOx	100	Y	40	Y
CO	100	Y	100	Y
PM10	100	Y	15	N
SOx	100	N	100	N

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)]
- The applicant certifies in writing, prior to the issuance of the permit, that the facility meets all applicable limitations and standards under the Clean Air Act (42 U.S.C. 7401, et seq.) and all applicable emission limitations and standards which are part of the State Implementation Plan approved by the Environmental Protection Agency or is on a compliance schedule to meet such limitations.
- Public notice

In accordance with Rule 1703(a)(F), a copy of the application must be provided to the EPA, the Federal Land Manager for any Class I area located within 100 km of the source, and to the federal official charged with direct responsibility for management of any lands within the Class I area. A copy of the preliminary decision, the analysis, and notice of any action taken must also be provided to the above agencies. The analysis shall include a determination on the impact on visibility due to the project.

There are 3 Federally-designated mandatory Class I areas (40 CFR Part 81 §81.405) within 100 km of the project: Cucamonga Wilderness, San Gabriel Wilderness, and Agua Tibia Wilderness. The areas are managed by the US Forest Service, and a copy of the application was been provided to this agency on November 30, 2022 (a copy of the letter to the forest service is included in the file for reference).

Distances to Class I Areas

Federal Class I Area	Distance from AES HB (km)
Cucamonga Wilderness	69
San Gabriel Wilderness	69.9
San Gorgonio Wilderness	107.6
San Jacinto Wilderness	114.2
Agua Tibia Wilderness	90.6
Joshua Tree NP	145.4

BACT Analysis

BACT is required for any pollutant for which there is a net emission increase, therefore, for the proposed modification, BACT applies for all PSD pollutants. The BACT determination for NO2, CO, SO2, and PM10 is based on a top-down analysis. For major sources, BACT is determined at the time the permit is issued, and is the most stringent emission limitation or control technique which has been achieved in practice, or contained in any State Implementation Plan (SIP). Furthermore, a more stringent limit or control technique is also required if it is found to be technologically feasible and cost effective.

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 when the initial permits for the turbines were being evaluated in 2016 and 2017. Refer to A/N 578083, and Appendix M. Also refer to the BACT/LAER discussion pertaining to NOx shown under the Rule 1325 analysis.

Th results of the BACT analyses is summarized in the following table:

Combined Cycle Turbine Required BACT

NOx	CO	VOC	PM_{10}	SOx	NH3
2.0 ppmvd @ 15% O2, 1 hour average	1.5 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 CO limit applies to combined cycle turbines with no supplemental duct firing

The turbines meet the emission levels. The emission levels of NOx, CO, VOC, and NH3 in the table are manufacturer guaranteed emissions under normal operating conditions.

Control Levels for the HBEP Combined Cycle Turbines

NOX	CO	VOC	PM10	SOX	NH3
2.0 ppmvd @ 15% O2, 1 hour average	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)*

In conclusion, the combined cycle turbines as configured meet the current BACT standards for all criteria pollutants as well as NH3.

<u>Modeling Analysis</u>

NO2 and PM10 were modeled for annual impacts.

For the maximum ambient air quality impacts resulting from NOx emissions, the total annual emissions were calculated using a baseline emission rate of 73,409 lbs/yr, + 6,300 lbs/yr which is the PTE increase in annual NOx for the adjustment to the non-cold start up emission rates in a previous permit revision (reference A/N 618931), + 16,800 lbs/yr which is the PTE increase in annual NOx for the additional 1000 hours proposed under these applications, for a total annual NOx of 96,509 lbs/yr per turbine (model input = 1.39 g/s per turbine). The baseline NOx is derived from the modeling done under the initial permit evaluation for these turbines. The initial modeling was performed by first evaluating a screening level analysis to determine the exhaust parameter/emission rate combination which resulted in the maximum impact scenario. The baseline emission rate is documented in Appendix C, Table 2, Page 104 of 125. TN 210807, Huntington Beach Energy Project's Revised Air Permit Application Document, Docketed March 22,2016 for Exhaust Scenario CC07.

For the maximum ambient air quality impacts resulting from NOx emissions at 50 km, the total annual emissions were based on the new maximum PTE of 142,600 lbs/yr per turbine (model input = 2.0529 g/s per turbine).

For the maximum ambient air quality impacts resulting from PM10 emissions, the total annual emissions were based on the new maximum PTE of 64,940 lbs/yr, per turbine (model input = 0.935 g/s per turbine).

The modeling also included the PTE emissions from the auxiliary boiler of 1,313 lbs/yr NOx and 1,392 lbs/yr PM10.

Results of the model were added to the background concentrations to determine if the project plus background exceed either the CAAQS or NAAQS. Meteorological data was taken from the John Wayne Airport NWS station for 2018-2020. NO2 background concentrations were taken from Station 17 - North Central Orange County and I-5 Near Road. PM10/PM2.5 background concentrations were taken from Station 19 – Saddleback Valley.

Stack parameters used in the model are shown in Appendix I.

The modeling results are summarized in the following table and indicate that there will be no violation of either the CAAQS or NAAQS. Additionally, the model results show that the emissions from the equipment do not exceed the Class II significant Impact Level (SIL), therefore, cumulative modelling is not required.

All results reflect emissions from the 3 stacks combined.

Project + Background

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Concentration (ug/m3)	AAQS ug/m3
NO2	Annual	0.91	39.13	40.0	57
PM10	Annual	0.698	19	19.7	20
PM2.5	Annual	0.698	8.81	9.5	12

The NAAQS for annual NO2 is 100 ug/m3

Project vs Class II SIL

Pollutant	Averaging Time	Maximum Modeled Concentration (ug/m3)	Significant Impact Level (ug/m3)	PSD Class II Increment Standard (ug/m3)
NO2	Annual	0.91	1	25
PM10	Annual	0.7	1	30

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.

Project vs Class I SIL (impacts at 50 km)

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	0.0093	0.1	2.5
PM10	Annual	0.0048	0.2	1.0

Note: NO2 emissions for this model were input as 142,600 lbs/yr, or 2.0529 g/s.

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.

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 221 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 3.2.

The modeling was reviewed by SCAQMD modeling staff and deemed acceptable. Refer to the modeling review memo in Appendix L.

Rule 1714 – PSD for Greenhouse Gases

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.

For an existing source being modified, the major source threshold (for permits issued after 7/1/11) for GHGs is 100,000 tpy CO2e and 100/250 tpy GHGs mass emissions (based on PTE). Once determined to be a major source, the significant increase is defined as ≥ 75,000 tpy CO2e and > 0 tpy GHG mass, including any decreases from the modification (netting). If the existing source is minor before the modification, then a project that 'in and of itself' results in actual or PTE emissions increase of ≥ 100,000 tpy CO2e and ≥ 100/250 tpy GHG mass is considered a significant increase and therefore, a major modification. There is no netting allowed for minor sources. For major modifications that are subject to PSD for another pollutant (anyway sources), the significant increase threshold for GHGs is a net increase of ≥ 75,000 tpy CO2e AND a net increase greater than 0 tpy total mass GHG. The mass emissions major source threshold is determined by the source category. In the case of a combined cycle turbine plant, the major source threshold is 100 TPY.

The AES HB facility is defined as a major source for GHGs, because the emissions are greater than 100 tpy see Appendix E). With the addition of 1000 hours of annual operating time, there is a significant increase of GHGs, and therefore, a PSD analysis is required for GHGs.

On June 23, 2014 the U.S. Supreme Court issued its decision in *Utility Air Regulatory Group v. EPA, 134 S.Ct. 2427 (2014)* ("*UARG")*, which concluded that increases in GHG emissions alone cannot trigger the review of a permit application under PSD. An analysis under PSD for GHGs emission is only required when a source triggers PSD review for other criteria pollutants. These types of sources are termed "anyway" sources.

The additional 1000 hours of operation for the turbines would fall under the definition of an "anyway" project, since the proposal results in emissions above the PSD thresholds for NOx and PM10.

Pollutant	PSD Major Source Threshold, tpy PTE	Facility Existing Major Source	Major Modification Threshold, tpy	Proposed Modification Major?
GHG/CO2e	100/100,000	Y	0/75,000	Y

Change in GHG Emissions New PTE vs Past Actual 2 Turbines Combined

Pollutant	Post Modification Annual PTE	Actual Annual Emissions	Change	PSD Threshold
	TPY	TPY	TPY	TPY
CO2e	2,011,109.4	1,546,497.0	464,612.4	75,000

Actual emissions based on 2021 reported fuel use of 12,930.22 mmscf/yr Turbine 1, and 12,815.98 mmscf/yr Turbine 2 and the following equation:

CO2e = (120,017*F + 2.26*21*F + 0.226*310*F)/2000 = 60.067*F (in tons)

F = fuel use in mmscf

Actual Emissions are based on 2021 only, not a previous 2 year average. The turbines began operation in early 2020 and operated all of 2020 as a merchant plant. The turbines began operating as a "Power Purchase Tolling Option" in January 1, 2021 under AES' Power Purchase Agreement with SCE , The units capacity factor under the PPS is more representative of the turbine's operational profile going forward.

Requirements for a Significant GHG Emission Increase at a Major Stationary Source

As a significant increase at a major stationary source, and as an 'anyway' source, the project is subject to the requirements as specified under Rule 1703, which includes BACT, 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. 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.

GHG BACT Analysis

A top down BACT analysis pertaining to GHG emissions was performed for the turbines when they were evaluated for initial permits in 2016/2017. The analysis focused on Carbon Capture and Storage (CCS) and thermal efficiency. The conclusion of the evaluation was that CCS was not feasible, and that thermal efficiency was BACT. A summary of the GHG BACT analysis from the initial permit evaluation is shown in Appendix N for reference. AES was asked to provide any updates or supplemental information to their analysis for this current permit revision. AES declined to provide any updates and stated that the analysis and its conclusions remain valid for the current permit revision proposal.

Based on theoretical calculations shown in Appendix B, the turbines are expected to meet the California GHG emission performance standard of 1,000 pounds of CO_2 per net megawatt hour.

Rule 2011/2012 – RECLAIM, Monitoring Recording and Recordkeeping Requirements

The turbines are classified as major NOx sources and SOx process unit under RECLAIM. As a major NOx source, the turbines are required to measure and record NOx concentrations and calculate mass NOx emissions with a Continuous Emissions Monitoring System (CEMS). The CEMS includes in-stack NOx and O2 analyzers, a fuel meter, and a data recording and handling system. The CEMS is required to be calibrated daily, with a semi annual or annual RATA, and a semi annual bias test. The fuel meter is required to be calibrated annually. NOx emissions are reported to AQMD electronically on a daily basis, as well as summarized in quarterly and annually emissions reports. The CEMS system for the turbines has received initial approval from South Coast AQMD and are installed and operating. The CEMS certification tests were completed at the end of March 2020, therefore at this time the CEMS has been granted provisional certification pending South Coast AQMD's review of the testing.

As a SOx process unit, the turbines' fuel use must be measured and recorded and SOx emissions must be calculated using the emission factor on the permit, and reported on a quarterly basis.

Regulation XXX – Title V

The AES Huntington Beach facility is subject to Title V requirements because its potential to emit (PTE) of NOx, CO, VOC, and PM10 emissions are greater than the major source thresholds. Additionally, the turbines and Boiler 2 at this facility are defined as an affected unit under the Acid Rain provisions, making this facility an affected source [40CFR Part 72, §72.6(a)(3)].

The Huntington Beach facility is currently operating under a valid Title V permit. The Title V permit was initially issued on August 19, 1999, renewed on May 4, 2011, renewed again on April 29, 2016, and most recently renewed on March 23, 2022. The permit was last revised on April 13, 2022 when the final permits to operate were issued for the combined cycle plant and auxiliary equipment (administrative revision).

The proposed increase in the allowable annual hours of operation is considered a **significant revision** to the existing Title V permit because the estimated daily increase in emissions of NOx, VOC, and PM10 exceed the de minimis significant thresholds of Rule 3000.

Rule 3000 Table 1

Contaminant	De Minimis Threshold, lbs/day	Project Emissions Increase, lbs/day
HAP	30	9.7
VOC	30	31.8
NOx	40	92.1
PM10	30	46.6
SOx	60	8.2
CO	220	41.9

** Project emissions increase can be referenced in Appendix A, Table A.23. Note that the project daily emissions increase are calculated by taking the annual increase and dividing by 365*

As a significant revision the proposed permit is subject to a 45 day EPA review and comment period [Rule 3004(j)], review by affected states [3004 (m)], as well as a 30 day public notice period [Rule 3006].

NSPS for Stationary Gas Turbines - 40CFR Part 60 Subpart KKKK

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

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

State Regulations

California Environmental Quality Act (CEQA)

The initial proposal to install the turbines at the AES Huntington Beach Generating Station was subject to the licensing procedure under the California Energy Commission (CEC). The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. The license for the turbines was approved in 2017.

The proposed revision to add 1000 hours of annual allowable operating time to each turbine's permit is also subject to CEC approval in the form of a modified license. The procedure consists of the development of a staff assessment document which examines environmental, public health and safety, and engineering aspects of the proposed modification, based on the information provided by the applicant, government agencies (such as the SCAQMD), interested parties, and other sources available at the time the staff assessment is 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 staff assessment and recommendation is then presented to the Energy Commission Board at a regularly scheduled monthly meeting. After discussions, and in consideration of any public comments received on the proposal, the board members will then vote for either approval or disapproval of the project.

The SCAQMD is responsible for reviewing the CEC's findings and analysis and providing comments if necessary.

Mandatory GHG Reporting Regulation

This regulation applies to various industries which emit GHGs. Some industries are subject regardless of the level of GHG emissions, some are only subject if their emissions are ≥ 10,000 MTYP. Requirements include monitoring, recording, and reporting GHG emissions. All electricity generating units which are required to report CO2 through the acid rain program, 40CFR Part 75, are subject to this regulation.

Under § 95112, electricity generating units (EGU) are required to report net and gross power generated and fuel consumption by fuel type. § 95163(b) specifies that EGUs fired exclusively on liquid and/or gaseous fuel may determine CO2 by using 40 CFR Part 60 Subpart UUUUa. Under § 95103(k) calibration of the flow meter used to provide data for the GHG calculation is required. Calibration frequency can be 1) as specified in 40CFR Part 98, 2) per the manufacturer recommended calibration frequency, or 3) at least once every 3 years. Calibration is also required immediately upon replacement or repair of the device. Frequency of reporting of GHGs is once per year

Federal Regulations

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 MW. 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.

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 B show that the units can be expected to meet this limit.

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.

Note that if the combined cycle turbines supply less than 1,519.5 GW, then the applicable "limit" of 120 lbs CO2/mmbtu is essentially the default factor for estimating CO2 emissions from natural gas fired combustion equipment contained in 40CFR Past 98 Subpart C Table C-1 (53.02 kg/mmbtu).

NESHAPS for Stationary Gas Turbines - 40CFR Part 63 Subpart YYYY

This regulation is applicable to existing, new, or reconstructed turbines at a major source of HAP emissions. New units are defined as those for which construction or reconstruction commenced after January 14, 2003. 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.

Provisions of this regulation include limiting formaldehyde emissions for new units to 91 ppbvd, monitoring of the catalyst inlet temperature for new units with oxidation catalyst, An initial performance test and subsequent annual tests are required, and there are requirements for record keeping and reporting.

The total combined potential HAP emissions from the combined cycle turbines utility Boiler #2, and the auxiliary boiler are about 14 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 E). Note that as of March 9, 2022, EPA has removed the stay of the formaldehyde limit applicable to lean pre-mix and diffusion flame gas turbines at major sources of HAP.

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. The AES Huntington Beach facility is a major source, and the turbine pre-control emissions are greater than the major source thresholds for NOx, CO, and VOC (see Appendix E). The turbines are subject to an emission limit for each of these pollutants, and use control systems to meet these limits. Therefore, the turbines are subject to CAM for NOx CO, and VOC. Note that the turbines were already subject to CAM for these pollutants prior to the proposal to add an additional 1000 hours of operating time.

NOx

- <u>Emission Limit</u> – NOx is subject to a 2.0 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – NOx is controlled with SCR
- ✓ <u>Requirement</u> - 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

- <u>Emission Limit</u> – CO is subject to a 1.5 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – CO is controlled with the oxidation catalyst.
- ✓ <u>Requirement</u> – 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

- <u>Emission Limit</u> – VOC is subject to a 2.0 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – VOC is controlled with the oxidation catalyst.
- ✓ <u>Requirement</u> – 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.

<u>40 CFR Part 72 - (Acid Rain Provisions)</u>

The facility will be subject to the requirements of the federal acid rain program, because the turbines are power generating units operated by a utility (defined in «:515#as any entity selling electricity). The acid rain program is a cap and trade regulation. Facilities are required to cover SO2 emissions with "SO2 allowances". Facilities that were existing when the regulation was adopted in 1993 were given allowances based on past operation.

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 180 days after the unit commences commercial operation [«:817+e,+5,\. 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.

40CFR Part 98 – Mandatory Greenhouse Gas Reporting
This regulation is applicable to owners and operators of certain facilities that directly emit GHGs as well as certain suppliers. Requirements include monitoring, recording, and reporting GHG emissions. Table A-3 of the regulation lists the source categories, which includes electricity generation units that report CO_2 mass emissions year round through the acid rain program, 40CFR Part 75.

§ 98.3(i) requires periodic calibration of the flow meters Calibration error must be within ± 5% of the reference method.

Frequency of reporting of GHGs is once per year.

Public Notice Requirements

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

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. 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.

The specific requirements of this rule are as follows:

Notify the public of the application, the preliminary determination, the degree of increment consumption that is expected from the source or modification, whether an alternative to a U.S. EPA approved model was used, and of the opportunity for written public comment.

The applicant shall be responsible for the distribution of the public notice to each address within a 1/4- mile radius of the project or such other greater area as determined appropriate by the Executive Officer.

Send a copy of the notice of public comment to the applicant, the U.S. EPA Administrator, and to officials and agencies having cognizance over the location where the proposed construction would occur as follows: any other state or local air pollution control agencies, the chief executives of the city and county where the source would be located, any comprehensive regional land use planning agency, and any State or Federal Land Manager, or Indian Governing body whose lands may be affected by emissions from the source or modification.

Provide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations

Rule 3006
Rule 3006 requires the notice be available on the South Coast AQMD website, and also that it be sent by hardcopy or electronic mail to those who request in writing to be on a list.

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.

40 CFR Part 70
Part 70 requires that notice be given by either publishing in a newspaper of general circulation in the area where the source is located or by posting on a public Web site. It further requires that the notice be provided to persons on a mailing list. The mailing list can be generated either through web-based sign up methods such as a hyperlink sign-up function or radio button on the Web site, and/or using a sign-up sheet at a public hearing. The requirements for the notice contents are generally the same as what's specified in Rule 3006.

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

To meet these public notice requirements, the notice being prepared for this Title V significant revision will be published in a newspaper which is circulated in the location of the source, and will be sent to the following:

Air Pollution Control Districts
- San Diego APCD
- Antelope Valley AQMD
- Mohave Desert AQMD
- Ventura County APCD
- Imperial County APCD
- San Joaquin APCD

Affected States
- Pala Band of Mission Indians
- Pechanga Band of Luiseno Mission Indians

Environmental groups
- Communities for a Better Environment
- Natural Resources Defense Council
- California Safe Schools
- Coalition for Clean Air

EPA
CARB
Those who have requested to be on a mailing list

The permit documents are also made available to the public at South Coast AQMD headquarters and on the South Coast AQMD website.

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

Reference Appendix K for a complete list of notice recipients.

5.0 EMISSIONS

AES has requested an increase in the allowable annual hours of operation. This will result in higher annual PTE for all pollutants. Under the initial permit to construct, the turbines were evaluated at maximum hourly, daily and monthly operation, therefore the increase in annual hours of operation dies not change the calculations for hourly, daily and monthly emissions.

Detailed calculations are shown in Appendices A, B, and C. Following is a summary.

Maximum Hourly Emissions, Start Up and Shutdown, Single Turbine

Pollutant	Cold Start Lbs/event	Non-cold Start Lbs/event	Shutdown Lbs/event
NOx	61	32	17
CO	325	137	137
VOC	36	25	25

Maximum Hourly Emissions, Normal Operation, Single Turbine

Pollutant	Normal Lbs/hr
NOx	16.8
CO	7.65
VOC	5.8
PM10	8.5
SOx	4.6
NH3	2.98

Daily PTE (Maximum), Single Turbine

Pollutant	Operating Scenario	Controlled Daily Emissions 1 Turbine
NOx	1 cold start + 1 non-cold start + 2 shutdowns + 20.5 hrs normal	457.4
CO	1 cold start + 1 non-cold start + 2 shutdowns + 20.5 hrs normal	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

Monthly PTE Total and 30-Day Average Emissions, Single Turbine

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	15 cold starts+ 47 non-cold starts+62 shutdowns+674.5 hrs normal	14,370.6	479.0
CO	15 cold starts+ 47 non-cold starts+62 shutdowns+674.5 hrs normal	24719.9	824.0
VOC	15 cold starts+ 47 non-cold 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

Annual PTE

A. Pre Modification Annual PTE

Pollutant	Operating Scenario	Total Annual Emissions 1 Turbine, lbs	Total Annual Emissions 2 Turbines, lbs
NOx	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	125,800	251,600
CO	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	196,705	393,410
VOC	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	64,760	129,520
PM10	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	56,440	112880
SOx	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	9,960	19,920
NH3	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 6100 hrs normal	94,550	189,100

B. Post Modification Annual PTE

Pollutant	Operating Scenario	Total Annual Emissions 1 Turbine, lbs	Total Annual Emissions 2 Turbines, lbs
NOx	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 7100 hrs normal	142,600	285,200
CO	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 7100 hrs normal	204,355	408,710
VOC	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 7100 hrs normal	70,560	141,120
PM10	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 7100 hrs normal	64,940	129,880
SOx	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 7100 hrs normal	11,460	22,920
NH3	80 cold starts+88 warm starts + 332 hot starts + 500 shutdowns + 7100 hrs normal	110,050	220,100

Change in Annual PTE Pre-Modification vs. Post-Modification
Single Turbine

Pollutant	Pre Modification Annual Emissions	Post Modification Annual Emissions	Change		Average Daily Increase, lbs/day
			Lbs/yr	tpy	
NOx	125,800	142,600	16,800	8.4	46.0
CO	196,705	204,355	7,650	3.825	21.0
VOC	64,760	70,560	5,800	2.9	15.9
PM10	56,440	64,940	8,500	4.25	23.3
SOx	9,960	11,460	1,500	0.75	4.1
NH3	94,550	110,050	15,500	7.75	42.5

Change in Annual PTE Pre-Modification vs. Post-Modification
2 Turbines Combined

Pollutant	Pre Modification Annual Emissions	Post Modification Annual Emissions	Change		Average Daily Increase, lbs/day
			Lbs/yr	tpy	
NOx	251,600	285,200	33,600	16.8	92.1
CO	393,410	408,710	15,300	7.65	41.9
VOC	129,520	141,120	11,600	5.8	31.8
PM10	112,880	129,880	17,000	8.5	46.6
SOx	19,920	22,920	3,000	1.5	8.2
NH3	189,100	220,100	31,000	15.5	84.9

GHG Emissions

A. Pre Modification GHG Emissions

GHG PTE

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

B. Post Modification GHG Emissions

GHG PTE

GHG	Hourly Tons Per Turbine	Annual Tons Per Turbine	Annual Tons 2 Turbines
CO2	152.9	1,004,515.7	2,009,031.3
CH4	2.89E-03	18.93	37.85
N2O	2.89E-04	1.90	3.79
Total Mass	152.9	1,004,536.5	2,009,073.0
CO2e	153.1	1,005,554.7	2,011,106.3

Change in GHG Emissions Pre Modification vs Post Modification

2 Turbines Combined

Pollutant	Pre Modification Annual PTE	Post Modification Annual PTE	Change
	TPY	TPY	TPY
CO2e	1,747,875.2	2,011,106.4	263,231.2

GHG calculation based on 2,248 mmbtu/hr (site average temperature conditions) and Pre modification - 6640 hours/yr, post modification - 7640 hours per year. AES HB is an existing PSD major source for GHGs (100,000 tpy)

Toxic Emissions

A. Pre Modification Toxic Emissions

Pollutant		Annual Emissions 1 Turbine, lbs/yr	Annual Emissions 2 Turbines, lbs/yr
1,3 Butadiene		6.30	12.6
Acetaldehyde		2581.56	5163.12
Acrolein		52.92	105.84
Benzene		47.76	95.52
Ethyl Benzene		467.55	935.1
Formaldehyde		5263.51	10527.02
Naphthalene		19.07	38.14
PAH		13.17	26.34
Propylene Oxide		424.52	849.04
Toluene		1907.49	3814.98
Xylene		936.53	1873.06
TOTAL	Lbs/yr	11,720.4	23,440.8
	Tons/yr	5.86	11.72

B. Post Modification Toxic Emissions

Pollutant		Annual Emissions 1 Turbine, lbs/yr	Annual Emissions 2 Turbines, lbs/yr
1,3 Butadiene		7.24	14.49
Acetaldehyde		2970.36	5940.72
Acrolein		60.89	121.78
Benzene		54.95	109.90
Ethyl Benzene		537.97	1075.93
Formaldehyde		6056.23	12112.47
Naphthalene		21.95	43.90
PAH		15.15	30.30
Propylene Oxide		488.46	976.92
Toluene		2194.77	4389.53
Xylene		1077.58	2155.16
TOTAL	Lbs/yr	13,485.6	26,971.1
	Tons/yr	6.74	13.49

Change in Annual Emissions Pre-Modification vs. Post-Modification Single Turbine

Pollutant	Pre Modification Annual Emissions, lbs/yr	Post Modification Annual Emissions, lbs/yr	Change, Lbs/yr
1,3 Butadiene	6.30	7.24	0.94
Acetaldehyde	2581.56	2970.36	388.8
Acrolein	52.92	60.89	7.97
Benzene	47.76	54.95	7.19
Ethyl Benzene	467.55	537.97	70.42
Formaldehyde	5263.51	6056.23	792.72
Naphthalene	19.07	21.95	2.88
PAH	13.17	15.15	1.98
Propylene Oxide	424.52	488.46	63.94
Toluene	1907.49	2194.77	287.28
Xylene	936.53	1077.58	141.05
		Total Lbs/yr	1765.17
		Tons/yr	0.88

Change in Annual Emissions Pre-Modification vs. Post-Modification
2 Turbines Combined

Pollutant	Pre Modification Annual Emissions, lbs/yr	Post Modification Annual Emissions, lbs/yr		Change, Lbs/yr
1,3 Butadiene	12.6	14.49		1.89
Acetaldehyde	5163.12	5940.72		777.6
Acrolein	105.84	121.78		15.94
Benzene	95.52	109.90		14.38
Ethyl Benzene	935.1	1075.93		140.83
Formaldehyde	10527.02	12112.47		1585.45
Naphthalene	38.14	43.90		5.76
PAH	26.34	30.30		3.96
Propylene Oxide	849.04	976.92		127.88
Toluene	3814.98	4389.53		574.55
Xylene	1873.06	2155.16		282.1
		Total	Lbs/yr	3530.34
			Tons/yr	1.77

6.0 COMPLIANCE RECORD REVIEW

The South Coast AQMD compliance data base shows 3 Notices to Comply and 4 Notices of Violation for this facility in the last 5 years, summarized as follows:

Notice No.	Violation Date	Reason
E45012	8/22/18	Inaccurate APEP submittal
E46533	12/15/20	Inaccurate QCER submittal
E52282	2/23/22	Failure to report emission on time, inaccurate QCER submittal
P66881	7/1/19	Failure to submit accurate APEP, failure to use correct BAF
P69259	10/4/19	CCTG #1 exceeds opacity limit for more than 3 minutes
P67930	11/16/19	CCTG #1 exceeds opacity limit for more than 3 minutes
P66889	5/7/21	Auxiliary Boiler NOx emissions exceed 5.0 ppm

The facility also received 41 complaints for smoke, odors, dust, or other reasons during the period from August to December 2019. Most of these complaints are attributed to the construction phase of the plant, as well as the initial commissioning of the CCTG's.

After receiving the NOV's for visible emissions violations, AES requested emergency variance relief (Case 5202-5). AES claimed that they did not know that the commissioning activities would result in visible emissions and furthermore they believed that the permit allowed the visible emissions. The variance was granted on 10/10/19 based on the fact that there was no other way to get the units into the operational phase other than to proceed through the commissioning operation. As a condition of the variance, AES was required to have CARB certified visible emissions evaluators stationed at the plant during the remaining days when the units were run prior to emission controls being used. This phase of operation ended on October 14, 2019.

There are currently no outstanding compliance issues with the facility. The follow up status for the notices are ‘in compliance’.

Annual Compliance Certification

The annual compliance certification report on August 20, 2021 for the compliance year July 1, 2020 to June 30, 2021 indicated nine instances of non-compliance during the reporting period.

On July 3, 2020, the ammonia pumps for CCTG 1A tripped, causing the unit to exceed its NOx BACT concentration limit of 2.0 ppm for 1 hour. The concentration for the hour was 2.2 ppm. The logic controlling the pumps was modified to avoid the problem in the future.

On August 25, 2020 the facility lost power which resulted in steam release and cooling of the turbines and their oxidation catalysts. This caused the turbines to exceed their 137 lb CO limit during the non-cold start up the following day. Periodic switchyard equipment cleaning has been scheduled to avoid salt moisture deposits and reduce the likelihood of reoccurrence in the future.

On October 20, 2020 the output for CCTG 1A dropped below minimum load causing its NOx to exceed the BACT concentration limit of 2.0 ppm for 1 hour. The turbines were tuned by the manufacturer to reduce the likelihood of reoccurrence in the future.

On October 26, 2020 the plant exceeded its gross MW output permit limit of 693.8 MW for 1 hour when the output was 694.0 MW. AES configured a high priority audible alarm to alert the operator if the output is exceeded in the future.

On October 26, 2020 the auxiliary boiler’s SCR heater tripped resulting in a loss of ammonia flow which caused the boiler to exceed its NOx BACT concentration limit of 5.0 ppm for 1 hour. AES configured the ammonia vapor temperature on the plant’s DCS and added a high priority audible alarm.

On December 23. 2020 CCTG 1A exceeded its 137 lb CO limit for non -cold start up due to the low temperature of the oxidation catalyst. AES will review and increase HRSG auxiliary steam sparging as necessary to maintain adequate oxidation catalyst temperature during reserve shutdown hours.

On May 2, 2021 CCTG 1A exceeded its NOx BACT concentration limit of 2.0 ppm for 2 hours due to high inlet NOx concentration to the SCR caused by a problem with the turbine’s gas control valve. Additionally, the ammonia injection rate limit of 242 lbs/hr was exceeded. The turbine was tuned by the manufacturer to reduce the likelihood of reoccurrence in the future.

On May 7, 2021 the auxiliary boiler exceeded its NOx BACT concentration limit of 5.0 ppm for 1 hour. Cause of the exceedance is unknown.

On June 7, 2021 CCTG 1A exceeded its permit limit of 2 starts per day. The unit tripped after losing instrument air caused by a failure of the air compressor. The compressor's intercooler backpressure regulator was tuned by the manufacturer to reduce the likelihood of reoccurrence in the future.

The facility filed has also submitted several deviation reports for the time period from July 1, 2021 to June 30, 2022.

On November 8, 20221 the NOx CEMS for CCTG 1A was out of service due to the failure of the sample condenser. The condenser unit was replaced with a like replacement on the same day.

On December 267, 2021, CCTG 1B exceeded the NOx limit of 2.0 ppm and the CO limit of 1.5 ppm due to a fuel stop ratio valve failure on CCTG 1A which caused a loss in steam flow to the shared steam turbine. And resulted in an automatic run back for CCTG 1B. AES will replace the a fuel stop ratio valve actuator on CCTG 1A. CCTG 1A will remain offline until the actuator is replaced.

On January 1, 2022 CCTG 1B exceeded the NOx limit of 2.0 ppm due to an automatic run back which dropped the unit below minimum emissions compliance load to prevent tripping. Loose SRV Contactor connectors were tightened, and the control logic was adjusted to increase the level in the High Pressure Drum where runback is initiated from 6 inches to 12 inches.

On May 1, 2022 the monthly average differential pressure across the SCR serving CCTG 1B was 1.7" H20, which exceeded its limit of 1.6" H20. This was caused by insulating material being released into the SR for a failed weld in the air intake duct. The catalyst was vacuumed clean during the week of May 2, 2022, and the differential pressure was confirmed to be in the normal range during the next start up on 5/14.

The annual compliance certification report on August 25, 2022 for the compliance year July 1, 2021 to June 30, 2022 indicated seven instances of non-compliance during the reporting period.

On November 8, 2021 the CEMS for CCTG 1A went out of service when the condenser (chiller) failed. The chiller was replaced on the same day with a like unit.

On December 26, 2021 CCTG 1B exceeded its NOx and CO limits due to the unit experiencing and automatic runback which dropped the unit below minimum emissions compliance load to avoid tripping. The run back was in turn caused by CCTG 1A tripping because the Fuel Stop Ratio Valve (SRV) failed. CCTG 1A was kept offline until the SRV was repaired on 12/31/21.

On January 1, 2022 CCTG 1B exceeded its NOx limit for 1 hour due to the unit experiencing and automatic runback which dropped the unit below minimum emissions compliance load to avoid tripping. The run back was in turn caused by CCTG 1A tripping because of loose connection on the Fuel Stop Ratio Valve (SRV) connector. The loose connector was repaired on 1/1/22.

On April 1, 2022 CCTG 1B exceeded its 2.0 ppm NOx limit for 1 hour due to a missing fuel gas flow signal which is required to control ammonia injection into the SCR. Work was being done on the flow meter which required disconnection of rhe flow meter output. The work was scheduled to be completed before the unit started but took longer than planned. Flowmeter output was reconnected as soon as the verification was completed. Future flow meter verification activities will be performed when the unit is offline or operating at steady state so that the ammonia flow can be controlled manually.

On April 24, 2022 CCTG 1A exceeded its NOx start up limit of 61 lbs due to an incorrectly set ramp rate. The ramp rate setting had been changed by the manufacturer during a scheduled outage The ramp rate setting was corrected.

On May 1, 2022 it was discovered that CCTG B exceeded its monthly average differential pressure limit of 1.6” H2O across the SCR catalyst. The monthly average pressure for April was 1.7” H2O. This was due to insulation material being released into the SCR from a weld failure in the unit air intake duct. CCTG 1B was taken offline and the SCR catalyst was cleaned. The SCR differential pressure was confirmed within the normal range after the next start up on 5/14.

Additionally, on November 4, 2022, the facility submitted a deviation report for an incident that occurred on October 28, 2022. CCTG 1B exceeded its NOx cold start up limit due to a failure to synchronize to the power grid resulting in an extended time operating below minimum emissions compliant load. The failure was due to blow line filter fuse. The unit was taken offline and the fuse was replaced.

7.0 CONDITIONS TO BE IMPOSED

The following condition changes are recommended:

1. Change the PM2.5 limit in condition F2.1 from 100 tpy to 70 tpy to reflect the major source threshold limit that came into effect in 2017.
2. Change the annual allowable operating hours in condition C1.9 from 6640 hrs/yr to 7640 hrs/yr
3. Add the temperature range for ammonia injection in condition E57.2
4. Change the NOx RTC withholding amount in condition I297.1 to reflect the additional 1000 hours of operation
5. Change the SOx RTC withholding amount in condition I298.1 to reflect the additional 1000 hours of operation
5. Minor changes to the wording in conditions C1.7 and C1.8

All other conditions remain the same.

Proposed changes or additions are shown in **bold/underline**, proposed deletions are shown in ~~strikethrough~~

FACILITY LEVEL CONDITION

F2.1
THE OPERATOR SHALL LIMIT EMISSIONS FROM THIS FACILITY AS FOLLOWS:

CONTAMINANT	EMISSIONS LIMIT
PM2.5	LESS THAN ~~100~~ **70** TONS IN ANY ONE YEAR

For purposes of demonstrating compliance with the ~~100~~ **70** 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 the auxiliary boiler PM2.5 = 7.54 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._

COMBINED CYCLE TURBINE CONDITIONS

//

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

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

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: 2.66 lbs/mmcf, PM10: 3.94 lbs/mmcf, CO: 15.18 lbs/mmscf during normal operation 325 lbs for a cold start and 137 lbs for a non cold start

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]

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 turbine start ups and turbine shutdowns.
[Rule 1703-PSD, Rule 2005]

A195.7
The 1.5 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during 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 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 non-cold start ups shall not exceed 47 per month.

Daily Start Up Limit - The number of start ups shall not exceed 2 per day

Annual Start Up Limit - The number of cold start ups shall not exceed 80 per year, and the number of 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 combustion turbine has been shutdown for 48 hours or more. A cold start up shall not exceed 60 minutes. Emissions during the 60 minutes that includes a cold start up shall not exceed the following: NOx - 61 lbs., CO – 325 lbs., VOC – 36 lbs.

A non-cold start up is defined as a start up which occurs after the combustion turbine has been shutdown for less than 48 hours. A non-cold start up shall not exceed 30 minutes. Emissions during the 30 minutes that includes a non-cold start up shall not exceed the following: NOx - 32 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 for both NOx and CO based on minute data. If during start up the process is aborted the process will count as one start up.

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

The operator shall ~~calculate~~ **verify** compliance with the VOC emission limits by using fuel use data and an emission factor of 18 lbs/mmcf for a cold start and 25 lbs/mmscf during a non-cold start.

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 ~~calculate~~ **verify** compliance with the emission limits for CO and NOx after the CEMS certification based upon readings from the SCAQMD certified CEMS.

The operator shall ~~calculate~~ **verify** compliance with the VOC emission limits by using fuel use data and an emission factor of 32 lbs/mmcf.

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~~ **7640** in any one calendar year.

The limit includes baseload operation as well as start ups and shutdowns.

Combined Cycle Turbines No. 1 and No. 2 shall not simultaneously operate at minimum load **(approximately 44% of full load rating)** 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]

D29.6
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	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 in accordance with an AQMD approved test protocol.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. If the results of any calendar year test show non-compliance with the limit, then quarterly tests must be conducted and at least 4 consecutive tests must show compliance with the limit before calendar year testing can resume.

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 protocol shall be submitted to the AQMD engineer no later than 60 days before the proposed test date and shall be approved by the AQMD before the test commences, unless otherwise specified by the Executive Officer. 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.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis) and mass rate (lb/hr). All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

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

The 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.

The test shall be conducted in accordance with an AQMD approved test protocol.

The protocol shall be submitted to the AQMD engineer no later than 60 days before the proposed test date and shall be approved by the AQMD before the test commences, unless otherwise specified by the Executive Officer. 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.

For natural gas fired turbines only, for the purpose of demonstrating compliance with BACT as determined by SCAQMD. 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 the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F

The use of this modified method for VOC compliance determination does not mean that it is more accurate 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 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.

Source test results shall be submitted to the District no later than 60 days after the source test was 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 shall also be reported in terms of grains per DSCF corrected to 3 percent oxygen (dry basis) and corrected to 12 percent CO2 (dry basis).

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, 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 operated in accordance with approved SCAQMD Rule 218 CEMS plan application.

The CEMS shall measure the CO concentration at least once per minute.

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 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 218, Rule 218.1, Rule 1703-PSD]

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

NOx concentration in ppmv
O2 in percent

The CEMS shall measure the NOx concentration at least once per minute

Concentrations shall be corrected to 15 percent oxygen on a dry basis. The CEMS shall be installed and operated in accordance with approved SCAQMD REG XX CEMS plan application.

The CEMS will convert the actual NOx concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.
[Rule 1703 – PSD, Rule 2005, Rule 2012, 40CFRF Part 75]

E57.2
The operator shall vent this equipment to the SCR and the oxidation catalysts whenever the turbine is in operation.

Ammonia injection shall begin after the SCR inlet temperature reaches between 400 Deg F and 570 deg F if the injection of ammonia will not result in ammonia emissions in excess of the ammonia slip concentration limit.
[**Rule 429.2**, Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]

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]

E193.6
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:

$CO2 = 60.009 * FF$

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 ~~873,035~~ **1,004,516** tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO2 emissions shall not exceed ~~967.6~~ **951.8** 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 (D115)
This equipment shall not be operated unless the facility holds ~~156,093~~ **16,800** pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

1297.4 (D124)
This equipment shall not be operated unless the facility holds ~~156,093~~ **16,800** pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

I298.1 (D115)
This equipment shall not be operated unless the facility holds ~~14,803~~ **11,460** 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 ~~14,803~~ **11,460** 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]

I298.4 (D124)
This equipment shall not be operated unless the facility holds ~~14,803~~ **11,460** 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 ~~14,803~~ **11,460** 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]

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

> Date, time, and duration of each start-up and shutdown, and the type of start up (cold, or non-cold).
> 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, gross and net, total hours of operation and fuel consumption.

[Rule 1303(b)(2) – Offsets, Rule 1135]

Huntington Beach Energy Project
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Appendix A

Criteria Pollutant Emission Calculations

Normal Operation

- Table A.1 Manufacturer Guaranteed Emissions CCTG

Pollutant	Guarantee
NOx	2.0 ppm @15%
CO	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	1.5	1.5	1.5
Hourly Emissions, lb/hr	7.07	7.49	7.52
Daily Emissions, lb/day	169.7	179.8	180.5
lbs/mmcf	3.48	3.48	3.48
lbs/mmbtu	0.0033	0.0033	0.0033
	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)	10.0/1.5	51.0/7.65
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 (2.0 ppm*70.1 mmscf/hr*46 lbs/lb-mole)/385 cf/lb-mole = 16.8 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 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 2 basic types of starts – cold and non-cold.[3] A cold start up is defined as a start of the CGT 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.

[3] *In their initial permit application, AES defined 3 types of starts - cold, warm, and hot. But the emissions and duration of the warm and hot starts are exactly the same, so for regulatory purposes, warm and hot starts can be combined and simply called a 'non-cold start.'*

A non-cold start occurs after a shutdown lasting up to 48 hours and will take about 30 minutes to complete.

The turbines can be shutdown in 30 minutes.

For each combined cycle turbine, AES anticipates up to 15 cold and 47 non-cold starts per month, and 80 cold and 420 non-cold starts 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 Non-cold Start Emissions Data

Pollutant	Time, minutes	Inlet, lbs/hr	Inlet Total, lbs	Reduction, %	Total Outlet, lbs
NOx	0-10	64	~~11~~ **14.5**	32	~~6~~ **10**
	10-20	95	~~16~~ **88.9**	72	~~19~~ **16**
	20-30	75	~~13~~ **12**	80	~~3~~ **2.4**
				TOTAL	~~17~~ **32**
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. Total outlet NOx is approximated based on the high end of the results from start data shown in Appendix C, and AES' requested start limit.

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	Non-cold Start, 30 minutes	Shutdown
	Lbs/event	Lbs/event	Lbs/event
NOx	61	32	10
CO	325	137	133
VOC	36	25	32

Maximum Daily PTE

Pre Modification = Post Modification

Maximum daily PTE will not change as a result of the additional 1000 hours of annual operation for the turbine. This is because the turbines maximum daily PTE is currently based on a full day of operation.

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	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
Non-cold Start (total lbs)	32	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 non-cold 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	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
Non-cold Start (1)	0.5	32	137.0	25.0	4.25	2.3	0
TOTAL	24	457.4	884.8	243.9	195.5	105.8	317.75
Scenario 2							
Normal Operation	24	403.2	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
Non-cold-Start (1)	0.5	32	137.0	25.0	4.25	2.3	0
TOTAL	24	1658.7	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	457.4
CO	1 cold, 1 non-cold, 2 shutdowns, 20.5 hours normal	1773.5	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 non-cold, 2 shutdown scenario.

Monthly PTE

Pre Modification = Post Modification

Monthly PTE will not change as a result of the additional 1000 hours of annual operation for the turbine. This is because the turbines monthly PTE is currently based on a full month of operation.

Table A.12 Maximum Monthly Operation CCTG

Event	# Per Month	Duration/event	Duration/month, hrs
Cold Start	15	1 hour	15
Non-cold Start	47	30 minutes	23.5
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
Non-cold Start	32	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	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
Non-cold	23.5	47	1504	6439	1175	199.8	108.1	0
Shutdown	31	62	620	8246	1984	263.5	142.6	0
Normal @ 65.8 deg	674.5	//////	11331.6	5159.9	3912.1	5733.3	3102.7	10454.8
	Total, lbs/month		14370.6	24719.9	7611.1	6324	3422.4	10454.75
	Average lbs/day		479.0	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	5691.6	4315.2	6324	3422.4	11532
	Total, lbs/month		12499.2	5691.6	4315.2	6324	3422.4	11532
	Average lbs/day		416.6	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+ 47 non-cold starts+62 shutdowns+674.5 hrs normal	14370.6	479.0
CO	15 cold starts + 47 non-cold starts+62 shutdowns+674.5 hrs normal	24719.9	824.0
VOC	15 cold starts + 47 non-cold 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 PTE

A. Current PTE Calculation

Table A.17 Maximum Annual Operation per CCTG

Event	# Per Year	Duration/event	Duration/yr, hrs
Cold Start	80	1 hour	80
Non-cold Start	420	30 minutes	210
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	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
Non-cold Start (total lbs)	32	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 Pre Modification Annual PTE

Operating Mode	Emissions Per Turbine, lbs					
	NOx	CO	VOC	PM10	SOx	NH3
Cold Starts	4880	26000	2880	680	120	0
Non-cold Starts	13440	57540	10500	1785	315	0
Shutdowns	5000	66500	16000	2125	375	0
Normal Operation	102480	46665	35380	51850	9150	94550
TOTAL 1 TURBINE	125800	196705	64760	56440	9960	94550
TOTAL 2 TURBINES	251600	393410	129520	112880	19920	189100

Sample Calcs:

NOx cold starts = 61 lbs/start *80 starts/yr = 4880 lbs
NOx normal operation = 16.8 lbs/hr * 6100 hrs = 102480 lbs

PM10 non-cold starts = 4.25 lbs/start * 420 starts/yr = 1785 lbs
PM10 normal operation = 8.5 lbs/hr * 6100 hrs = 51850 lbs

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

B. Post Modification PTE Calculation

Table A.20 Maximum Annual Operation per CCTG

Event	# Per Year	Duration/event	Duration/yr, hrs
Cold Start	80	1 hour	80
Non-cold Start	420	30 minutes	210
Shutdown	500	30 minutes	250
100% Load @ 65.8 deg F	///////////////	///////////////	7100
		Total Hrs	7640

Table A.21 Post Modification Annual PTE

Operating Mode	Emissions Per Turbine, lbs					
	NOx	CO	VOC	PM10	SOx	NH3
Cold Starts	4880	26000	2880	680	120	0
Non-cold Starts	13440	57540	10500	1785	315	0
Shutdowns	5000	66500	16000	2125	375	0
Normal Operation	119280	54315	41180	60350	10650	110050
TOTAL 1 TURBINE	142600	204355	70560	64940	11460	110050
TOTAL 2 TURBINES	285200	408710	141120	129880	22920	220100

Sample Calcs:

NOx cold starts	=	61 lbs/start * 80 starts/yr	=	4880 lbs
NOx normal operation	=	16.8 lbs/hr * 7100 hrs	=	119280 lbs
PM10	=	4.25 lbs/start * 88 starts/yr	=	374 lbs
PM10 normal operation	=	8.5 lbs/hr* 7100 hrs	=	60350 lbs
SOx normal operation	=	1.5 lbs/hr * 7100 hrs/yr	=	10650 lbs

Table A.22
Change in Annual Emissions Pre-Modification vs. Post-Modification
Single Turbine

Pollutant	Pre Modification Annual Emissions	Post Modification Annual Emissions	Change		Average Daily Increase, lbs/day
			Lbs/yr	tpy	
NOx	125,800	142,600	16,800	8.4	46.0
CO	196,705	204,355	7,650	3.825	21.0
VOC	64,760	70,560	5,800	2.9	15.9
PM10	56,440	64,940	8,500	4.25	23.3
SOx	9,960	11,460	1,500	0.75	4.1
NH3	94,550	110,050	15,500	7.75	42.5

Table A.23
Change in Annual Emissions Pre-Modification vs. Post-Modification
2 Turbines Combined

Pollutant	Pre Modification Annual Emissions	Post Modification Annual Emissions	Change		Average Daily Increase, lbs/day
			Lbs/yr	tpy	
NOx	251,600	285,200	33,600	16.8	92.1
CO	393,410	408,710	15,300	7.65	41.9
VOC	129,520	141,120	11,600	5.8	31.8
PM10	112,880	129,880	17,000	8.5	46.6
SOx	19,920	22,920	3,000	1.5	8.2
NH3	189,100	220,100	31,000	15.5	84.9

Appendix B

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:

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)

Potential to Emit

The GHG potential to emit is based on heat input at baseload conditions (highest efficiency)

Pre Modification

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)

GHG PTE

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

Post Modification

Heat Input

Hourly Heat Input	2,273 mmbtu/hr	Based on low temperature conditions
Annual Heat Input	17,174,720 mmbtu/yr	Based on 2,248 mmbtu/hr (site average temperature conditions) and 7640 hrs/yr operation (includes start ups and shutdowns)

GHG PTE

GHG	Hourly Tons Per Turbine	Annual Tons Per Turbine	Annual Tons 2 Turbines
CO2	152.9	1,004,515.7	2,009,031.3
CH4	2.89E-03	18.93	37.85
N2O	2.89E-04	1.90	3.79
Total Mass	152.9	1,004,536.5	2,009,073.0
CO2e	153.1	1,005,554.7	2,011,106.3

Change in GHG Emissions Pre Modification vs Post Modification

2 Turbines Combined

Pollutant	Pre Modification Annual PTE	Post Modification Annual PTE	Change
	TPY	TPY	TPY
CO2e	1,747,875.2	2,011,106.4	263,231.2

GHG calculation based on 2,248 mmbtu/hr (site average temperature conditions) and Pre modification - 6640 hours/yr, post modification - 7640 hours per year. AES HB is an existing PSD major source for GHGs (100,000 tpy)

Estimated Emissions Based on Heat Rate

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. This information was provided by AES. For the post modification estimate, AES indicated that the additional 1000 hours of operating time occurs at the 1X1 configuration, as a worst case assumption.

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

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

Pre Modification

Heat Rate Summary

Operating Mode		Hours/Yr	Net Heat Rate Btu/kWhr	Notes
Baseload	1X1	1200	7,217	Average net at HHV from Table B.1
Baseload	2X1	4900	7,015	Average net at HHV from Table B.2
Start ups	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
	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

CO2
7657.6 btu/kWh * 1000 kWh/MWh * 1*10E-06 MMBtu/Btu * 53.06 kg CO2/MMBtu-HHV * 2.205 lb/kg = 895.9 lb CO2/MWH

895.9 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	7657.6 btu/kw-hr*1.08	=	8270.2 btu/kw-hr
CO2 with equipment degradation	895.9*1.08	=	967.6 lb CO2/netMWH @ HHV

Post Modification

Heat Rate Summary

Operating Mode		Hours/Yr	Net Heat Rate Btu/kWhr	Notes
Baseload	1X1	2200	7,217	Average net at HHV from Table B.1
Baseload	2X1	4900	7,015	Average net at HHV from Table B.2
Start ups	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
	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*2200 hrs + 7015 btu/h*4900 hrs +19783 btu/kWh*219 hrs + 7217 btu/kWh*71 hrs +11870 btu/kWh*250 hrs)/(7640) = 7532.8 btu/kWh

CO_2

7532.8 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

881.3 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	7532.8 btu/kw-hr*1.08	=	8135.4 btu/kw-hr
CO_2 with equipment degradation	881.3*1.08	=	951.8 lb CO_2/netMWH @ HHV

Appendix C

Air Toxic Emission Calculations

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.

Pre Modification

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

Pollutant	Emission Factor, lbs/mmcf	Maximum Hourly Emission Rate, lbs/hr	Annual Emissions 1 Turbine, lbs/yr	Annual Emissions 2 Turbines, lbs/yr
1,3 Butadiene	4.39E-04	9.48E-04	6.30	12.6
Acetaldehyde	1.80E-01	3.89E-01	2581.56	5163.12
Acrolein	3.69E-03	7.97E-03	52.92	105.84
Benzene	3.33E-03	7.19E-03	47.76	95.52
Ethyl Benzene	3.26E-02	7.04E-02	467.55	935.1
Formaldehyde	3.67E-01	7.93E-01	5263.51	10527.02
Naphthalene	1.33E-03	2.87E-03	19.07	38.14
PAH	9.18E-04	1.98E-03	13.17	26.34
Propylene Oxide	2.96E-02	6.39E-02	424.52	849.04
Toluene	1.33E-01	2.87E-01	1907.49	3814.98
Xylene	6.53E-02	1.41E-01	936.53	1873.06
		Total Lbs/yr	11,720.4	23,440.8
		Tons/yr	5.86	11.72

Post Modification

Data:

Maximum fuel use (@ 1050 btu/cf)	2.16 mmcf/hr
Maximum annual hours of operation (incl start/shutdown)	7,640 hrs/yr

Total Annual Fuel Use	16,502 mmcf/yr

Pollutant	Emission Factor, lbs/mmcf	Maximum Hourly Emission Rate, lbs/hr	Annual Emissions 1 Turbine, lbs/yr	Annual Emissions 2 Turbines, lbs/yr
1,3 Butadiene	4.39E-04	9.48E-04	7.24	14.49
Acetaldehyde	1.80E-01	3.89E-01	2970.36	5940.72
Acrolein	3.69E-03	7.97E-03	60.89	121.78
Benzene	3.33E-03	7.19E-03	54.95	109.90
Ethyl Benzene	3.26E-02	7.04E-02	537.97	1075.93
Formaldehyde	3.67E-01	7.93E-01	6056.23	12112.47
Naphthalene	1.33E-03	2.87E-03	21.95	43.90
PAH	9.18E-04	1.98E-03	15.15	30.30
Propylene Oxide	2.96E-02	6.39E-02	488.46	976.92
Toluene	1.33E-01	2.87E-01	2194.77	4389.53
Xylene	6.53E-02	1.41E-01	1077.58	2155.16
		Total Lbs/yr	13,485.6	26,971.1
		Tons/yr	6.74	13.49

Notes:

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.

Change in Annual Emissions Pre-Modification vs. Post-Modification
Single Turbine

Pollutant	Pre Modification Annual Emissions, lbs/yr	Post Modification Annual Emissions, lbs/yr		Change, Lbs/yr
1,3 Butadiene	6.30	7.24		0.94
Acetaldehyde	2581.56	2970.36		388.8
Acrolein	52.92	60.89		7.97
Benzene	47.76	54.95		7.19
Ethyl Benzene	467.55	537.97		70.42
Formaldehyde	5263.51	6056.23		792.72
Naphthalene	19.07	21.95		2.88
PAH	13.17	15.15		1.98
Propylene Oxide	424.52	488.46		63.94
Toluene	1907.49	2194.77		287.28
Xylene	936.53	1077.58		141.05
		Total	Lbs/yr	1765.17
			Tons/yr	0.88

Change in Annual Emissions Pre-Modification vs. Post-Modification
2 Turbines Combined

Pollutant	Pre Modification Annual Emissions, lbs/yr	Post Modification Annual Emissions, lbs/yr		Change, Lbs/yr
1,3 Butadiene	12.6	14.49		1.89
Acetaldehyde	5163.12	5940.72		777.6
Acrolein	105.84	121.78		15.94
Benzene	95.52	109.90		14.38
Ethyl Benzene	935.1	1075.93		140.83
Formaldehyde	10527.02	12112.47		1585.45
Naphthalene	38.14	43.90		5.76
PAH	26.34	30.30		3.96
Propylene Oxide	849.04	976.92		127.88
Toluene	3814.98	4389.53		574.55
Xylene	1873.06	2155.16		282.1
		Total	Lbs/yr	3530.34
			Tons/yr	1.77

Appendix D

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).

The RTC holding requirement for the additional 1000 hours of annual allowable operation time for the turbines is summarized as follows (reference Appendix A, Table A.22)

NOx RTC Holding Requirement

Equipment	Pre Modification NOx lbs/yr	Post Modification NOx, lbs/yr	NOx RTC Holding Requirement
CCTG 1	125,800	142,600	16,800
CCTG 2	125,800	142,600	16,800

- The current NOx RTC holding for the Huntington Beach facility is 104,788 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.

SOx RTC Holding Requirement

Equipment	Pre Modification SOx lbs/yr	Post Modification SOx, lbs/yr	SOx RTC Holding Requirement
CCTG 1	9,960	11,460	11,460
CCTG 2	9,960	11,460	11,460

- The current SOx RTC holding for the Huntington Beach facility is 12,252 lbs/yr. The initial SOx RTC allocation for this facility is 0 lbs/yr.

Appendix E

Major Source Determinations

//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 significant increase threshold for anyway sources (major modifications subject to PSD for another pollutant) is a net increase of 75,000 tpy CO2e AND a net increase greater than 0 tpy total mass GHG. For existing major sources (≥ 100,000 tpy CO2e and ≥ 250 tpy mass GHG) that are not anyway sources, 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 the project 'in and of itself' results in an increase of 100,000 tpy CO2e AND a net increase greater than 250 tpy mass GHG (without netting).

Pollutant	PSD Major Source Thresholds for AES HB (tpy)
NOx	100
CO	100
PM10	100
SOx	100
GHG	100,000

//Title V///

For Part 70 (Title V), the major source thresholds for a particular pollutant depends on the attainment status of the pollutant. For the federal standards, NO_2, SO_2, CO, and PM10 are in attainment, while PM2.5 is serious non-attainment and ozone is extreme non-attainment. For the state standards, PM10, PM2.5, and ozone are non-attainment, while NO2 and CO are attainment. For the South Coast Air Basin (SOCAB) the threshold levels are as follows:

Pollutant	SOCAB Major Source Thresholds (tpy)
VOC	10
NOx	10
SOx	100
CO	100
PM-10	100
PM-2.5	70
Single HAP	10
Combination of HAPS	25

//Rule 1325//

Rule 1325 defines a major polluting facility as one located in a federally designated non-attainment area for PM2.5 with actual emissions or a PTE of 70 tpy year or more of PM2.5 or its precursors. Precursor pollutants are NOx, SOx, VOC, and NH3.

//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). Refer to Appendix C for the combined cycle turbine calculations, and refer to AN 613956 for the auxiliary boiler calculations.

PRE MODIFICATION PTE

The pre modification PTE calculations reflect the operational restriction on Boiler 2 heat input (refer to A/N 641971) but do not reflect the proposed increase in annual operating hours for the 2 turbines.

Pollutant	CCTG 1 & 2 PTE	Auxiliary Boiler PTE	Boiler 2 PTE
	tpy	tpy	tpy
NOx	125.8	0.7	18.4
CO	196.7	3.8	797.5
VOC	64.8	0.5	11.2
PM10	56.44	0.7	4.3
PM2.5	56.44	0.7	4.3
SO2	9.96	0.2	1.7
NH3	94.6	0.2	9.7
CO2e	1,747,875	11,076	248,769.5
HAPs	11.7	0.1	0.08

Refer to Appendices A B and C for the turbine calculations and refer to AN 613956 for the auxiliary boiler calculations. Note that emission estimates for Boiler 2 are now based on exhaust flow of 20.54 mmscf/hr and fuel use of 1.94 mmscf/hr (previous was 29 mmscf/hr exhaust and 2.3 mmscf/hr fuel use) and a PM10 EF of 2.1 lbs/mmscf, refer to A/N 641971 for Boiler 2 calculations.

Hazardous Air Pollutants (HAPs) Potential to Emit

Pollutant	CCTG 1&2	Boiler No. 2	Aux Boiler	Total	
	Lbs/yr	Lbs/yr	lbs/yr	Lbs/yr	Tons/yr
1,3 Butadiene	12.6	//////////	//////////	14.49	7.25E-03
Acetaldehyde	5163.12	15.29	0.56	5959.38	2.98E+00
Acrolein	105.84	13.60	0.49	138.37	6.92E-02
Benzene	95.52	28.89	1.04	145.24	7.26E-02
Ethyl Benzene	935.1	33.99	1.24	1117.47	5.59E-01
Formaldehyde	10527.02	61.18	2.21	12187.18	6.09E+00
Naphthalene	38.14	5.10	0.05	49.99	2.50E-02
PAH	26.34	1.70	0.02	32.33	1.62E-02
Propylene Oxide	849.04	///////////	///////////	976.92	4.88E-01
Toluene	3814.98	132.56	4.77	4551.3	2.28E+00
Xylene	1873.06	98.57	3.55	2275.71	1.14E+00
Hexane	//////////	22.09	0.83	27.03	1.35E-02
Propylene	//////////	263.41	95.40	408.30	2.04E-01
Total, lbs/yr	23440.8	676.38	110.16		
Total 4 sources, tpy			12.1		

Turbine emissions based on factors from AP-42, Boiler emissions based on factors from Ventura County APCD. Refer to A/N 641971 for the Boiler 2 calculations, and refer to AN 613956 for the auxiliary boiler calculations. Note that emission estimates for Boiler 2 are now based on fuel use of 1.94 mmscf/hr (previous was 2.3 mmscf/hr).

Pre Modification Facility Annual PTE Summary

Pollutant	Facility PTE, tpy	Major Source?		
		PSD	Title V	1325
NOx	144.9	Y	Y	Y
CO	998.0	Y	Y	//////////
VOC	76.5	Y	Y	Y
PM10	61.4	Y	Y	//////////
PM2.5	61.4	Y	Y	N
SO2	11.9	N	N	N
NH3	104.5	//////////	//////////	Y
CO2e	2,007,721	Y	//////////	//////////
HAPs	12.1	/////////	N	//////////

Emissions from the emergency fire pump engine and emergency diesel generator engine are not included because they are negligible.

POST MODIFICATION PTE

The post modification PTE calculations reflect both the operational restriction on Boiler 2 heat input (refer to A/N 641971), as well as the increase in annual operating hours for the 2 turbines from 6640 hrs/yr to 7640 hrs/yr

Pollutant	CCTG 1 & 2 PTE	Auxiliary Boiler PTE	Boiler 2 PTE
	tpy	tpy	tpy
NOx	142.6	0.7	18.4
CO	204.4	3.8	797.5
VOC	70.6	0.5	11.2
PM10	64.9	0.7	4.3
PM2.5	64.9	0.7	4.3
SO2	11.5	0.2	1.7
NH3	110.3	0.2	9.7
CO2e	2,011,109	11,076	248,769.5
HAPs	13.5	0.1	0.08

Refer to Appendices A B and C for the turbine calculations, and refer to AN 613956 for the auxiliary boiler calculations. Note that emission estimates for Boiler 2 are now based on exhaust flow of 20.54 mmscf/hr and fuel use of 1.94 mmscf/hr (previous was 29 mmscf/hr exhaust and 2.3 mmscf/hr fuel use) and a PM10 EF of 2.1 lbs/mmscf, refer to A/N 641971 for Boiler 2 calculations.

Hazardous Air Pollutants (HAPs) Potential to Emit

Pollutant	CCTG 1&2	Boiler No. 2	Aux Boiler	Total	
	Lbs/yr	Lbs/yr	lbs/yr	Lbs/yr	Tons/yr
1,3 Butadiene	14.49	//////////	//////////	14.49	7.25E-03
Acetaldehyde	5940.72	3.67	0.56	5959.38	2.98E+00
Acrolein	121.78	3.26	0.49	138.37	6.92E-02
Benzene	109.90	6.93	1.04	145.24	7.26E-02
Ethyl Benzene	1075.93	8.16	1.24	1117.47	5.59E-01
Formaldehyde	12112.47	14.68	2.21	12187.18	6.09E+00
Naphthalene	43.90	1.22	0.05	49.99	2.50E-02
PAH	30.30	0.41	0.02	32.33	1.62E-02
Propylene Oxide	976.92	///////////	///////////	976.92	4.88E-01
Toluene	4389.53	31.81	4.77	4551.3	2.28E+00
Xylene	2155.16	23.66	3.55	2275.71	1.14E+00
Hexane	//////////	5.30	0.83	27.03	1.35E-02
Propylene	//////////	63.22	95.40	408.30	2.04E-01
Total, lbs/yr	26971.1	162.33	110.16		
Total 4 sources, tpy			13.68		

Turbine emissions based on factors from AP-42, Boiler emissions based on factors from Ventura County APCD. Refer to A/N 641971 for the Boiler 2 calculations, and refer to AN 613956 for the auxiliary boiler calculations. Note that emission estimates for Boiler 2 are now based on fuel use of 1.94 mmscf/hr (previous was 2.3 mmscf/hr).

Post Modification Facility Annual PTE Summary

Pollutant	Facility PTE, tpy	Major Source?		
		PSD	Title V	1325
NOx	161.7	Y	Y	Y
CO	1005.7	Y	Y	//////////
VOC	82.3	Y	Y	Y
PM10	69.9	N	Y	//////////
PM2.5	69.9	Y	Y	N
SO2	13.4	N	N	N
NH3	120.2	//////////	//////////	Y
CO2e	2,270,955	Y	//////////	//////////
HAPs	13.68	/////////	N	//////////

Emissions from the emergency fire pump engine and emergency diesel generator engine are not included because they are negligible.

//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.

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
Non-cold 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

Turbine Annual Operating Schedule

Event	# Per Year	Duration/event	Duration/yr, hrs
Cold Start	80	1 hour	80
Non-cold Start	420	30 minutes	210
Shutdown	500	30 minutes	250
100% Load @ 65.8 deg F	//////////////	//////////////	7100
		Total Hrs	7640

Turbine Pre Control Annual PTE and Major Source Determination

Pollutant	Annual Uncontrolled Emissions, 1 CCTG		Threshold	Major Source?
	Lbs/yr	Tpy	Tpy	
NOx	552,360	276.2	10	Y
CO	512,140	256.1	50	Y
VOC	70,560	35.3	10	Y
PM10	64,940	32.5	70	N
SOx	11,460	5.7	100	N

Appendix F

PSD and Rule 1325 Calculations

PSD and Rule 1325 require a comparison of the new annual PTE after modification to past actual annual emissions to determine if the proposed modification is significant.

The post modification PTE calculations are based on the following operational permit limits for the turbines:

Condition	Limits
C1.9	7640 hours per year operation including SU/SD
C1.7	2 SU per day, 62 SU per month, (15 cold/47 non-cold), 500 SU per year (80 cold/420 non-cold), 60 minutes per cold SU, 30 minutes per noncold SU, Cold SU = 61 lbs NOx, 325 lbs CO, 36 lbs VOC, Non cold SU = 32 lbs NOx, 137 lbs CO, 25 lbs VOC
C1.8	62 SD per month, 500 SD per year, 30 minutes per SD
A63.7	1,605 mmscf monthly fuel use (6324 lbs PM10/3.94 lbs/mmscf)

Post Modification Annual PTE

Operating Mode	Emissions Per Turbine, lbs					
	NOx	CO	VOC	PM10	SOx	NH3
Cold Starts	4880	26000	2880	680	120	0
Non-cold Starts	13440	57540	10500	1785	315	0
Shutdowns	5000	66500	16000	2125	375	0
Normal Operation	119280	54315	41180	60350	10650	110050
TOTAL 1 TURBINE	142600	204355	70560	64940	11460	110050
TOTAL 2 TURBINES	285200	408710	141120	129880	22920	220100

Detailed calculations are shown in Appendix A.

2021 Actual Emissions Combined Cycle Units

Pollutant	CCTG 1	CCTG 2	Total	
	Lbs/yr	Lbs/yr	Lbs/yr	TPY
NOx	79,739	78,325	158,064	79.0
CO	15,137	15,591	30,728	15.4
VOC	34,394	34,091	68,485	34.2
PM10/PM2.5	50,945	50,495	101,440	50.7
SOx	9,180	9,099	18,279	9.1
NH3	94,003	93,172	187,175	93.6

All pollutants as reported under AER. This data was used in the analysis because the turbines began operation in early 2020 and operated all of 2020 as a merchant plant. The turbines began operating as a "Power Purchase Tolling Option" in January 1, 2021 under AES' Power Purchase Agreement with SCE , The units capacity factor under the PPS is is more representative of the turbine's operational profile going forward

Change in Criteria Pollutant Annual Emissions New PTE vs Past Actual 2 Turbines Combined

Pollutant	Post Modification Annual PTE	Actual Reported Annual Emissions	Change		PSD Major Modification Threshold for AES HB, tpy
	Lbs/yr	Lbs/yr	Lbs/yr	tpy	
NOx	285,200	158,064	127,136	63.6	40
CO	408,710	30,728	377,982	189.0	100
VOC	141,120	68,485	72,635	36.3	40
PM10	129,880	101,440	28,440	14.2	15
PM2.5	129,880	101,440	28,440	14.2	70
SOx	22,920	18,279	4,641	2.3	40
NH3	220,100	187,175	32,925	16.5	40

Actual Emissions are based on 2021 only, not a previous 2 year average. The turbines began operation in early 2020 and operated all of 2020 as a merchant plant. The turbines began operating as a "Power Purchase Tolling Option" in January 1, 2021 under AES' Power Purchase Agreement with SCE , The units capacity factor under the PPS is is more representative of the turbine's operational profile going forward.

AES HB is an existing PSD major source for NO2, CO and PM10, (100 TPY), and an existing PM2.5 NSR major source for NO2, VOC, and NH3 (70 tpy)

A major polluting facility is on a pollutant specific basis, and a facility is considered to be a major polluting facility only for the specific pollutants with a PTE above the thresholds.

Change in GHG Emissions New PTE vs Past Actual
2 Turbines Combined

Pollutant	Post Modification Annual PTE	Actual Annual Emissions	Change	PSD Threshold
	TPY	TPY	TPY	TPY
CO2e	2,011,109.4	1,546,497.0	464,612.4	75,000

Actual emissions based on 2021 reported fuel use of 12,930.22 mmscf/yr Turbine 1, and 12,815.98 mmscf/yr Turbine 2 and the following equation:

CO2e = (120,017*F + 2.26*21*F + 0.226*310*F)/2000 = 60.067*F (in tons)

F = fuel use in mmscf

AES HB is an existing PSD major source for GHGs (100,000 tpy)

Detailed calculations are shown in Appendix B.

Regulation XVII
PTE to past actual

Pollutant	PSD Major Source Threshold for AES HB, tpy PTE	Facility Existing Major Source	Major Modification Threshold, tpy	Proposed Modification Major?
NOx	100	Y	40	Y
CO	100	Y	100	Y
PM10	100	Y	15	N
SOx	100	N	40	N
GHG	100,000	Y	75,000	Y

Rule 1335
PTE to past actual

Pollutant	Rule 1325 Major Source Threshold, tpy PTE	Facility Existing Major Source	Major Modification Threshold, tpy	Proposed Modification Major?
NOx	70	Y	40	Y
VOC	70	Y	40	N
PM2.5	70	N	70	N
SOx	70	N	70	N
NH3	70	Y	40	N

Appendix G

Rule 1303 Calculations

Daily Maximum PTE Comparison (Project Total, 2 Turbines)

Pollutant	Pre Modification Daily Maximum PTE(1)	Post Modification Daily Maximum PTE(1)	Change
	Lbs/day	Lbs/day	Lbs/day
NOx	914.8	914.8	0
VOC	487.8	487.8	0

(1) 457.4 lbs/day NOx per turbine, 243.9 lbs/day VOC per turbine.

Note that since the daily maximum PTE of the other equipment at the facility will not change, there is no need to include that equipment in the analysis.

Annual PTE Comparison (Project Total, 2 Turbines)

Pollutant	Pre Modification Annual PTE	Post Modification Annual PTE	Change	
	Lbs/yr	Lbs/yr	Lbs/yr	TPY
CO	393,410	408,710	15,300	7.65
PM10	112,880	129,880	17,000	8.5
SOx	19,920	22,920	3,000	1.5
HAP	23,441	26,971	3,530	1.77

Refer to Appendices A, B, and C for calculation methodology

Regulation XIII
PTE to PTE

Pollutant	Regulation XIII Major Source Threshold, tpy PTE	Facility Existing Major Source?	Major Modification Threshold	Proposed Modification Major?
NOx	10	Y	1 lb/day	N
CO	100	Y	50 tpy	N
VOC	10	Y	1 lb/day	N
PM10	100	Y	15 tpy	N
SOx	100	N	40	N
Single HAP	10	N	10 tpy	N
Combination HAPs	25	N	25 tpy	N

MAJOR MODIFICATION means any modification, as specified in subdivision (x), at an existing major polluting facility, as specified in subdivision (s), that will cause;

(1) an increase of one pound per day or more, of the **facility's** potential to emit oxides of nitrogen (NOX) or volatile organic compounds (VOCs), provided the facility is located in the South Coast Air Basin or the Riverside County portion of the Salton Sea Air Basin, or

(2) an increase of 40 tons per year or more, of the facility's potential to emit oxides of sulfur (SOX), or

(3) an increase of 15 tons per year or more, of the facility's potential to emit particulate matter with an aerodynamic diameter of less than or equal to a nominal ten microns (PM10); or,

(4) an increase of 50 tons per year or more, of the facility's potential to emit carbon monoxide (CO)

Appendix H

Past Actual Emissions and Heat Input

Past actual emissions can be used to determine the applicability of PSD (new PTE vs existing actual emissions), in the case of a PSD major source, to verify compliance with the monthly emission and monthly fuel use limits, and in this case, to develop the Plantwide Applicability Limit.

Heat Input Data(1)

Year	Month	Heat Input, mmbtu		
		Boiler 2	CCTG 1	CCTG 2
2020	January	66700.9	0	0
	February	589.4	0	0
	March	221478.9	4088.535	302.562
	April	49049.8	41858.47	71332.68
	May	132613.3	167431.4	219717.3
	June	50910.2	360156.5	346853.2
	July	190269.6	597479.4	596824.7
	August	259104.1	591931.7	662755.8
	September	183075.4	704475.8	691831
	October	197895.6	777479	732939.5
	November	353.9	447949.1	422596.7
	December	0	369608.5	298841.3
	Total	1352041.1	4062458.5	4043994.7
2021	January	313.3	1248849.1	1057958.4
	February	0	805384.5	709892.6
	March	0	1198868.9	1159749.7
	April	23060.5	1011454.3	991106.6
	May	33490.3	969387.8	954131.7
	June	226436.9	970915.2	900367.9
	July	335549	1480828.7	1462726.3
	August	226572.6	1242644.3	1237780.8
	September	163968.5	1142178.3	1148636.8
	October	707.9	1199058.9	1219894.9
	November	1081.2	1237566.2	1272526.0
	December	0	909327.7	1183056.9
	Total	1011180.2	13416464.0	13297828.7
Average Annual Heat Input Previous 24 Months		1181610.7	8739461.3	8670911.7

(1) As reported under the Acid Rain program

2020 Reported Emissions

Pollutant	Boiler 2	CCTG 1	CCTG 2	Aux Boiler	D113	D114
	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr
NOx	10725.69	47729.07	44616.60	1034.7	184.6	174.09
CO	516316.51	55902.98	53447.53	1496.73	40.15	37.86
VOC	7199.24	17818.47	17442.71	627.28	14.76	13.92
PM10/PM2.5	9948.04	21635.71	21015.49	864.66	13.19	12.44
SOx	785.37	3773.66	3660.22	95.18	2.46	2.32
Fuel Use, mmscf	1308.953	5315.012	5155.241	114.676	0.3936 Mgal	0.3712 Mgal

All data as reported under AER

2021 Reported Emissions

Pollutant	Boiler 2	CCTG 1	CCTG 2	Aux Boiler	D113	D114
	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr	Lbs/yr
NOx	8470.68	79739.01	78324.91	178.75	177.09	177.84
CO	384636.48	15137.03	14591.0	786.0	38.52	36.68
VOC	5363.17	34394.0	34090.51	499.87	14.16	14.22
PM10/PM2.5	7410.92	50945.08	50494.97	689.04	12.65	12.70
SOx	585.07	14591.0	9099.35	75.85	38.52	38.68
Fuel Use, mmscf	975.12	12930.22	12815.98	91.384	0.3776 Mgal	0.3792 Mgal

All data as reported under AER

2 Year Average

Pollutant	2020 Lbs/yr	2021 Lbs/yr	Average Lbs/yr
NOx	104464.8	167068.3	135766.5
CO	627241.8	415225.7	521233.7
VOC	43116.4	74375.9	58746.2
PM10/PM2.5	53489.5	109565.4	81527.5
SOx	8319.2	24428.5	16373.8

	PM2.5 Emissions				
Unit	2020	Reporting Factor	2021	Reporting factor	Average
Boiler 2	9948.04	7.60 lbs/mmcf	7410.92	7.60 lbs/mmcf	8679.48
CCTG 1	21635.71	4.071 lbs/mmscf	50945.08	3.94 lbs/mmscf	36290.4
CCTG 2	21015.49	4.077 lbs/mmscf	50494.97	3.94 lbs/mmscf	35755.23
Aux Boiler	864.66	7.54 lbs/mmscf	689.04	7.54 lbs/mmscf	776.85
D113	13.19	33.50 lbs/Mgal	12.65	33.50 lbs/Mgal	12.92
D114	12.44	33.50 lbs/Mgal	12.70	33.50 lbs/Mgal	12.57
				TOTAL	81527.45

Reported GHGs

Year	Reported GHGs, MTPY			
	CO2	CH4	N2O	CO2e
2019	N/A	N/A	N/A	254,435
2020	645,020	12	1	645652

As reported to CARB. Reporting by GHG species not initiated until 2021

Appendix I

Modeling

Modeling was performed for annual impacts from operation of the 2 turbines and the auxiliary boiler using American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) Version 21112, with the Lakes Environmental Software implementation/user interface, AERMOD View™ Version 10.0.13.

Stack Locations and Dimensions

Equipment	Easting (m)	Northing (m)	Base Elevation (m)	Stack Ht (m)	Stack Dia (m)
CCTG 1	409449	3723148	3.66	45.7	6.10
CCTG 2	409474	3723182	3.66	45.7	6.10
AB	409438	3723236	3.66	24.4	0.91

Stack Parameters

Equipment	Load	Exhaust Temp, K	Exit Velocity, m/s
CCTG 1	44%	350	11.8
CCTG 2	44%	350	11.8
AB	100%	432	21.2

Emission Rates

Equipment	Annual NOx		Annual PM10/PM2.5	
	Lbs/yr	g/s	Lbs/yr	g/s
CCTG 1	96,509	1.39	64,940	9.3489E-01
CCTG 2	96,509	1.39	64,940	9.3489E-01
AB	1,313	1.8902E-02	1,392	2.0035E-02

CCTG NO2 emissions includes baseline of 73,409 lbs/year + 6,300 lb/yr (increase in non-cold SU, reference A/N 618931) + 16,800 lbs/year (16.8 lb/hr x 1,000 hr/yr increase). Baseline NO2 emissions calculated as 8.38 lb/hr x 8,760 hrs/yr. Reference Exhaust Scenario CC07 (Appendix C, Table 2, Page 104 of 125. TN 210807, Huntington Beach Energy Project's Revised Air Permit Application Document, Docketed March 22,2016). This is the scenario used for modeling under the initial permit evaluation.

Results

Met data is from John Wayne Airport NWS station for 2018-2020. NO2 background concentrations are from Station 17 - North Central Orange County and I-5 Near Road. PM10/PM2.5 background concentrations are from Station 19 – Saddleback Valley.

For conversion of NOx to NO2, the Tier 2 Ambient Ratio Method 2 (ARM2) was used, with default ratios.

All results reflect emissions from the 3 stacks combined.

Project + Background

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3)	Total Concentration (ug/m3)	AAQS ug/m3
NO2	Annual	0.91	39.13	40.0	57
PM10	Annual	0.698	19	19.7	20
PM2.5	Annual	0.698	8.81	9.5	12

The NAAQS for annual NO2 is 100 ug/m3

Project vs Class II SIL

Pollutant	Averaging Time	Maximum Modeled Concentration (ug/m3)	Significant Impact Level (ug/m3)	PSD Class II Increment Standard (ug/m3)
NO2	Annual	0.91	1	25
PM10	Annual	0.7	1	30

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.

Project vs Class I SIL (impacts at 50 km)

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	0.0093	0.1	2.5
PM10	Annual	0.0048	0.2	1.0

Note: NO2 emissions for this model were input as 142,600 lbs/yr, or 2.0529 g/s.

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.

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 221 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 3.2.

Notes
Modeling was done for the project when it was initially permitted in 2016. The modeling at that time used met data from the John Wayne Airport NWS station, and background concentrations from Costa Mesa for NO2 and Mission Viejo for PM10/PM2.5. The Costa Mesa location was closed in 2017.

Also, at that time, a visibility analysis for 5 nearby state parks, wilderness and recreational areas (all Class II) was conducted. That same visibility analysis was not conducted for the current proposed modification.

Health Risk Assessment

The health risk calculations were performed using HARP2's Air Dispersion Modeling and Risk Tool (ADMRT, version 21081).

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

Gas Turbine TAC Emission Rates

Pollutant	Emission Factor	Emissions per CCTG	Pre Modification Annual Emissions	Post Modification Annual Emissions	Project Increase
	lbs/mmscf	lbs/hr	Lbs/yr	Lbs/yr	Lbs/yr
Ammonia	5 ppm	15.5	102920	118420	15500
1,3 Butadiene	4.39E-04	9.48E-04	6.30	7.24	0.94
Acetaldehyde	1.80E-01	3.89E-01	2581.56	2970.36	388.8
Acrolein	3.69E-03	7.97E-03	52.92	60.89	7.97
Benzene	3.33E-03	7.19E-03	47.76	54.95	7.19
Ethyl Benzene	3.26E-02	7.04E-02	467.55	537.97	70.42
Formaldehyde	3.67E-01	7.93E-01	5263.51	6056.23	792.72
Naphthalene	1.33E-03	2.87E-03	19.07	21.95	2.88
PAH	9.18E-04	1.98E-03	13.17	15.15	1.98
Propylene Oxide	2.96E-02	6.39E-02	424.52	488.46	63.94
Toluene	1.33E-01	2.87E-01	1907.49	2194.77	287.28
Xylene	6.53E-02	1.41E-01	936.53	1077.58	141.05

Hourly emission rates based on 2.16 mmscf/hr (maximum fuel use at low temp). Pre modification annual emissions based on 6,640 hrs/yr operation and post modification emissions based on 7,640 hrs/yr. Note that the emissions for the project increase used in the model are slightly different from the values in this table Refer to page 5 of the applicants revised Appendix C document dated August 2022.

Model Results – HRA (2 turbines combined, project increase only)

Receptor	Cancer Risk Per Million	Chronic Hazard Index
MEIR	0.86	0.000968
MEIW	0.02	0.000860
Sensitive receptor	0.59	0.000860

Appendix J

HUNTINGTON BEACH ENERGY PROJECT (HBEP)

RULE 1304.1 – ELECTRICAL GENERATING FACILITY FEE FOR USE OF OFFSET EXEMPTION – FEES CALCULATION

The project will utilize the offset exemption of Rule 1304(a)(2) for PM10 and VOC. The formula for calculating the single payment fee is as follows:

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

Where:

Fi	=	Offset fee for pollutant (i)
LiA1	=	Single Payment Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually for the first 100 MW (Table A1 of the rule)
LiA2	=	Single Payment Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually for capacity > 100 MW (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.

CPI Adjustment

Rule 1304.1 was adopted on 9/6/13, and the offset fee rates in the rule are effective for the fiscal year ending 6/30/14. For each successive fiscal year, the offset fee rates are adjusted for the Consumer Price Index (CPI) and rounded off. The CPI increases are: (1) 1.6% effective 7/1/14, (2) 1.4% effective 7/1/15, (3) 2.4% effective 7/1/16, (4) 2.5%

effective 7/1/17, (5) 3.4% effective 7/1/18, (6) 3.5% effective 7/1/19, (7) 0.0% effective 7/1/20, (8) 4.5% effective 7/1/21, and (9) 6.5% effective 7/1/22. Note the CPI increase for fiscal year 2021 includes a 2.8% increase for fiscal year 2020, which was deferred, and a 1.7% increase for fiscal year 2021.

LiA1

Pollutant	Starting Rate, $/lb	7/1/14 Adjustment, 1.6%	7/1/15 Adjustment, 1.4%	7/1/16 Adjustment, 2.4%	7/1/17 Adjustment, 2.5%	7/1/18 Adjustment, 3.4%	7/1/19 Adjustment, 3.5%	7/1/20 Adjustment, 2.8%	7/1/21 Adjustment, 1.7%	7/1/22 Adjustment 6.5%
PM10	24911	25310	25664	26280	26937	27853	28828	29635	30138	**32098**
VOC	1159	1178	1194	1223	1253	1296	1341	1379	1402	**1493**

LiA2

Pollutant	Starting Rate, $/lb	7/1/14 Adjustment, 1.6%	7/1/15 Adjustment, 1.4%	7/1/16 Adjustment, 2.4%	7/1/17 Adjustment, 2.5%	7/1/18 Adjustment, 3.4%	7/1/19 Adjustment, 3.5%	7/1/20 Adjustment, 2.8%	7/1/21 Adjustment, 1.7%	7/1/22 Adjustment 6.5%
PM10	99643	101237	102655	105118	107746	111410	115309	118538	120553	**128389**
VOC	4635	4709	4775	4890	5012	5182	5364	5514	5608	**5972**

AES provided generation data for the period of April 2015 through March 2017 (see email dated 4/3/17).

Unit	Rating	April 2015- March 2016	April 2016-March 2017	2 Year Average
	MW	MWh gross	MWh gross	
HB1	215	325,634	261,106	293,370
RB7	480	210,768	181,013	195,891
			Total	489,261

The 693.8 MW-gross total of the replacement units will be offset by 215 MW provided by the retirement of HB Unit 1 and 480 MW from the retirement of RB Unit 7.

C2yravgexisting = (293,370 MW- gross, Unit 1) + (195,891 MW-gross, RB Unit 7)
= **489,261 MW-gross**

//

PRE MODIFICATION (6640 HRS/YR)

//

The following values are used in the equation:

Factor	PM10	VOC
PTErep	422 lbs/day	507 lbs/day
LiA1	$32,098/lb/day	$1,493/lb/day
LiA2	$128,389/lb/day	$5,972/lb/day
OFi	1.0	1.2
MW	693.8 MW	693.8 MW
Crep	4,606,832 MWh	4,606,832 MWh
C2yr	489,261 MW	489,261 MW

Notes:
PTErep is calculated as follows:
PM10 – 210.8 lbs/day*2 (CCTG = **422 lbs/day**,
VOC – 253.7 lbs/day*2 (CCTG) = **507 lbs/day**

Crep is calculated as follows:
Combined Cycle Units (693.8 MWs) 693.8 MW * 6640 hrs = **4,606,832 MWh** (starts and shutdowns included)

PM10

F_{PM10} = $[(32098\times100/693.8) + 128389 \times (693.8-100)/693.8] \times 1.0 \times 422 \times [(4606832 - 489261)/4606832]$

F_{PM10} = $[(4626.405) + (109883.811)] \times (1.0) \times (422) \times (0.894)$

F_{PM10} = \$43,201,040.17/yr

VOC

F_{VOC} = $[(1493\times100/693.8) + 5972 \times (693.8-100)/693.8] \times 1.2 \times 507 \times [(4606832 - 489261)/4606832]$

F_{VOC} = $[(215.192) + (5111.233)] \times (1.2) \times (507) \times (0.894)$

F_{VOC} = \$2,897,093.69/yr

PM10 = \$ 43,201,040.17
VOC = \$ 2,897,093.69

PRE MODIFCATION TOTAL SINGLE PAYMENT FEE = \$46,098,133.86

//

POST MODIFICATION (7640 HRS/YR)

//

The following values are used in the equation:

Factor	PM10	VOC
PTErep	422 lbs/day	507 lbs/day
LiA1	\$32,098/lb/day	\$1,493/lb/day
LiA2	\$128,389/lb/day	\$5,972/lb/day
OFi	1.0	1.2
MW	693.8 MW	693.8 MW
Crep	5,300,632 MWh	5,300,632 MWh
C2yr	489,261 MW	489,261 MW

Notes:
PTErep is calculated as follows:
PM10 – 210.8 lbs/day*2 (CCTG = **422 lbs/day**,
VOC – 253.7 lbs/day*2 (CCTG) = **507 lbs/day**

Crep is calculated as follows:
Combined Cycle Units (693.8 MWs) 693.8 MW * 7640 hrs = **5,300,632 MWh** (starts and shutdowns included)

PM10

F_{PM10} = $[(32098\times100/693.8) + 128389 \times (693.8-100)/693.8] \times 1.0 \times 422$

		$\times [(5300632 - 489261)/5300632]$
F_{PM10}	=	$[(4626.405) + (109883.811)] \times (1.0) \times (422) \times (0.908)$
F_{PM10}	=	\$43,877,566.60/yr

VOC

F_{VOC}	=	$[(1493\times100/693.8) + 5972 \times (693.8-100)/693.8] \times 1.2 \times 507$
		$\times [(5300632 - 489261)/5300632]$
F_{VOC}	=	$[(215.192) + (5111.233)] \times (1.2) \times (507) \times (0.908)$
F_{VOC}	=	\$2,942,462.05/yr

PM10 = $ 43,877,566.60
VOC = $ 2,942,462.05

POST MODIFCATION TOTAL SINGLE PAYMENT FEE = $46,820,028.65

TOTAL AMOUNT DUE = $46,820,029-$46,098,134 = <u>$721,895</u>
(Post Mod – Pre Mod)

///

The facility paid the initial fee at the time the permits to construct were issued in April 2017. The next fee due date was upon the start of construction. This was in October 2020 when construction started on the combined cycle units. In 2021, the facility notified South Coast AQMD that it would switch to the single payment option. The facility provided the single payment of $39,053,168 on 9/30/21 payment by wire transmittal.

Calculated Fee	Amount Paid	Date	Notes
$2,479.174	$2,479,174	Apr 2017	This is the initial fee paid upon issuance of the permits to construct

$2,107,655	0	Oct 2019	The amount paid is the calculated fee minus the initial fee paid. The balance of $371,519 remains as a credit.
$2,107.655	$1,736,156	Oct 2020	The amount paid is the calculated fee minus the $371,519 initial fee remaining credit
$43,268,498	$39,053,168	Sep 2021	Facility switches to single payment. Amount paid is the calculated fee minus the amount paid to date.

TOTAL PAID = 43,268,498

Total Due = 721,895

Appendix K

Public Notice

SCAQMD will provide the notice and related documents to the following recipients:

To	Contact
AES Huntington Beach[1]	Weikko Wirta
CEC[1]	Joe Douglas
USEPA[1]	Gerardo Rios
CARB	Courtney Graham
Forest Service Region 5	Andrea Nick
US Forest Service	Jennifer Eberlin
City of Huntington Beach	Sean Joyce
County of Orange	Frank Kim
SCAG	IGR@scag.ca.gov
National Park Service	Don Shepherd
National Park Service, Pacific West	Tonnie Cummings
San Diego APCD	Paula Forbis
Antelope Valley AQMD	Bret Banks
Mojave Desert AQMD	Brad Poiriez
Ventura County APCD	Ali Ghasemi
Imperial County APCD	Matt Dessert
San Joaquin Valley APCD	Samir Sheikh
Pala Band of Mission Indians	Robert Smith
Pechanga Band of Luiseno Mission Indians	Marc Macarro
CBE	Bahram Fazeli
CBE	Julia May
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	E. Joaquin Esquivel
California Regional Water Quality Control Board, Region 4	Renee Purdy
California Regional Water Quality Control Board, Region 8	Jayne Joy
Cal OSHA	Jeff Killip
Department of Water Resources	Karla Nemeth
California Coastal Commission	John Ainsworth
Morongo Band of Mission Indians	Pamela Atcity
Agua Caliente Band of Cahuilla Indians	Reid D. Milanovich
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	Rachel Peterson

All contacts receive the public notice
1- These contacts also receive the Statement of Basis and the Draft Permit

Additionally, SCAQMD will send 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.

AES will mail the notice to all addresses with ¼ mile of the facility.

Appendix L

Modeling Review Memo

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
ENGINEERING & PERMITTING
MEMORANDUM

TO: Chris Perri

FROM: Brandon Hebert

DATE: 12/28/2022

FACILITY NAME: AES Huntington Beach, LLC

FACILITY ID: 115389

APPLICATION NUMBER(S): 633199, 633201

SUBJECT: Review of Air Quality Impact Analysis and Health Risk Assessment for a Modification to 2 Combined Cycle Gas Turbines and an Auxiliary Boiler

South Coast AQMD Engineering & Permitting (E&P) modeling staff completed the review of the air quality impact dispersion modeling analysis conducted for the proposed modification to 2 Combined Cycle Gas Turbines (CCGT) located at 21730 Newland St, Huntington Beach, CA 92646.

AES Huntington Beach, LLC operating under FID 115389 submitted ANs 633199 and 633201 to increase the permitted annual operating hours of two combined cycle gas turbines at the facility from 6,640 hrs/yr to 7,640 hrs/yr. The auxiliary boiler provides steam to assist the turbines during start-up. The primary function of the facility is to produce electrical power for the California grid.

The facility submitted an Air Quality Impact Analysis and Tier 4 Health Risk Assessment to show that the permit units will still comply with Rule 1303, Rule 1401, Rule 1703, and Rule 2005. The proposed modification will not increase short-term emissions since the maximum hourly fuel consumption will remain the same. Therefore, no analysis is required for the 1-hour NO_2 standard, 24-hour PM standards, or acute hazard index.

Staff's detailed review is included in Attachment A. In summary, no issues were found with the air dispersion modeling.

HRA Review
AES Huntington Beach, LLC
A/N 633199, 633201

December 28, 2022

Table 1 - Annual Ambient Air Quality Standard Results for Rules 1303 and 2005

Pollutant (attainment)	Background	Project Impact[a]	Total	Standard	Exceed Standard?
NO_2 (μg/m3)	39.10	0.88	39.98	57 (CA); 100 (N)	No
Pollutant (non-attainment)	**Project[a]**		**Significant Change Threshold**		**Exceed Threshold?**
PM_{10} (μg/m3)	0.68		1.0		No
$PM_{2.5}$ (μg/m3)	0.68		1.0		No

[a]Project impact includes emissions from 2 CCGTs and 1 auxiliary boiler

Table 2 - Impacts on Class I Areas for Rule 1703

Pollutant	Project Impact	Significant Impact Limit (SIL)	Exceed Class I SIL?
NO_2 (μg/m3)	0.0092	0.10	No
PM_{10} (μg/m3)	0.043	0.27	No

Table 3 - Impacts on Class II Areas for Rule 1703

Pollutant	Project Impact	Significant Impact Limit (SIL)	Exceed Class II SIL?
NO_2 (μg/m3)	0.88	1.0	No
PM_{10} (μg/m3)	0.68	1.0	No

Table 4 - HRA Results for Rule 1401

Unit	Receptor Type	Cancer Risk (in one million)	Chronic Hazard Index	Cancer Risk Threshold (in one million)	Chronic Hazard Index Threshold
CCGT1	Sensitive	0.383	4.65×10^{-4}	10	1.0
	Worker	0.009	4.02×10^{-4}	10	1.0
CCGT2	Sensitive	0.433	5.27×10^{-4}	10	1.0
	Worker	0.010	4.66×10^{-4}	10	1.0

Staff spent a total of 42 hours conducting this review. If you have any questions, please contact Brandon Hebert at ext. 2380.

JW:BH

cc:

Attachment A
Modeling Review Checklist

Project Information					
Application #	633199, 633201		**Facility Name**	AES Huntington Beach, LLC	
Facility ID	115389		**Application Type**	Permit to Construct	
Date	12/28/2022		**Reviewer**	Brandon Hebert	
Modeling Review – Summary of Rule Compliance					
	Not applicable	**Yes**	**Yes with additional conditions**	**No**	**Requirement in Rules and Regulations**
1.	☐	☒	☐	☐	Rule 1303 NSR
2.	☐	☒	☐	☐	Rule 1401 NSR for TAC
3.	☐	☒	☐	☐	Rule 1703 PSD Analysis
4.	☐	☒	☐	☐	Rule 2005 NSR for RECLAIM
5.	☒	☐	☐	☐	Other:

Applicant's Modeling Analysis Review – Checklist	
6.	**Was the appropriate air quality model used to perform the analysis?** ☒**Yes** ☐ **No**
	AERSCREEN, version Insert version number AERMET, version 16216 AERMOD[1], version 22112 BPIP-Prime, version Click or tap here to enter text. AERMAP, version 18081 HARP-ADMRT, Click or tap here to enter text. HARP-RAST, version Click or tap here to enter text. Other Models: Click or tap here to enter text., version Click or tap here to enter text. Comments: Staff used AERMET version 16216, AERMOD version 22112, and AERMAP version 18081 during the review process.
7.	**Was the most representative background AQ monitoring data used in the analysis?** ☒ **Yes** ☐ **No** ☐ **Not applicable**
	Monitoring station: Central Orange County and I-5 Near Road Distance and direction to project: 12.5 miles NE Years Used: 2018-2020

[1] South Coast AQMD Modeling Guidance for AERMOD is on the website at: http://www.aqmd.gov/home/air-quality/air-quality-data-studies/meteorological-data/modeling-guidance

	Comments: Central Orange County and I-5 Near Road are the nearest monitoring stations with similar land uses.
8.	**Is project located in an identified Class I Area?** ☐ **Yes** ☒ **No** ☐ **Not applicable**
	Class I area: Cucamonga Wilderness & San Gabriel Wilderness Distance and direction to project: 69 km W to project Comments: For Class I areas, receptors were placed using a polar grid with a 50-km radius. Although the nearest Class I Area is more than 50 km from the site, AERMOD is only recommend for distances of 50 km or less. It was assumed that if the project impact at 50 km is less than the Class I SILs, the impacts at the Class I areas will be below the Class I SILs. The maximum impact at 50 km was found to be less than the Class I SILs. The impact at the point of maximum impact was found to be less than the Class II SILs.
9.	**Was the project modeled appropriately?** (Including but not limited to: surrounding topographic features, terrain options and terrain processing, project site boundary, locations of sources, structures, and buildings, building downwash, domain area, coordinates, etc.) ☒ **Yes** ☐ **No**
	Comments: Staff reviewed aerial maps and confirmed that the facility site boundary was modeled accurately. The nineteen buildings closest to the emission sources were included in the model and the building downwash effect was calculated. Elevation for sources, receptors, and buildings was gathered from the 1 arc-second National Elevation Dataset from the United States Geological Survey.
10.	**Were the appropriate model options used?** (Including but not limited to: regulatory and model options, pollutants, averaging time, NAAQS and CAAQS selections, rural/urban, deposition/depletion, NOx to NO2 conversion options, and etc.) ☒ **Yes** ☐ **No**
	Comments: The model was run using the regulatory default options, including the use of urban option, and the annual averaging periods. Short term averaging periods (1-hour NO_2, 24-hour PM, and acute health risk) were not analyzed since this modification is only for an increase in annual operating hours with no changes to maximum hourly emissions. The model was run using the Tier 2 Ambient Ratio Method 2 (ARM2) with U.S. EPA default minimum and maximum NO_2/NO_x in-stack ratios (0.5 and 0.9, respectively).
11.	**Was the most representative meteorological data[2] used?** ☒ **Yes** ☐ **No**
	Meteorological station: John Wayne Airport Distance and direction to project: 6.57 miles SW from station to project. Years: 2012-2016 Comments: John Wayne Airport met station is the most representative and the closest met station.

[2] It is required that the applicant use the most recent version of meteorological data that is either processed by or approved by South Coast AQMD and from the most appropriate meteorological station for the proposed project.

12.	**Was the source data modeled accurate?** (Including but not limited to: source type selections, source parameters (emission rate, temperature, exit velocity, release height and stack diameter, release type, operation scenarios, source group, variable emissions, in-stack ratios), and etc.) ☒ **Yes** ☐ **No**
	Comments: The CCGTs and auxiliary boiler were modeled as a point sources. The source parameters and emission rates were verified and deemed appropriate for the equipment. The stack locations and dimensions are detailed in Table 5. The stack parameters are detailed in Table 6. The NO_2 and PM emission rates are detailed in Table 7.
13.	**Was the receptor placement appropriate?** (Including but not limited to: dense enough receptor grid(s) with corresponding coordinates), receptor spacing, fenceline receptors, sensitive receptor and etc.) ☒ **Yes** ☐ **No**
	Nearest school, distance, and direction to project: Edison High School, 0.6 miles SW to project Other sensitive receptors: Residential receptors 300-400 feet northeast of the project Comments: The receptors modeled captured the maximum impact to ambient air. The multi-tier receptor grid consists of (1) 50-meter spacing within 1,000 meters and (2) 100-meter spacing between 1,000 meters and 2,000 meters. Fenceline receptors were placed with 10-meter spacing. For analysis of the Class I Areas, the receptors were placed using a polar grid with a 50-km radius. Although the nearest Class I Area is more than 50 km from the site, AERMOD is only recommend for distances of 50 km or less. It was assumed that if the project impact at 50 km is less than the Class I SILs, the impacts at the Class I areas are expected to be below the Class I SILs.
14.	**Did the project follow South Coast AQMD's health risk assessment procedure and have correct parameters? (**Including but not limited to: all the procedure, assumptions, and default parameters listed in South Coast AQMD HRA guidance. The South Coast AQMD's HRA procedures[3] require Hot Spots Analysis and Reporting Program (HARP) to be used in Tier 4 risk assessments for this Project for Rule 1401 compliance.**)** ☒ **Yes** ☐ **No** ☐ **Not applicable**
	Comments:
15.	**Are all data in the permit application package consistent with what was modeled?** (Including but not limited to: proposed conditions in permit application, reports, vendor guarantee data, manufacture data, emission estimation sources, calculations and spreadsheets, actual modeling I/O files, and etc.) ☒**Yes** ☐ **No**
	Comments:
16.	**Were all the model output files provided by the applicant?** (Including but not limited to: output settings, model processing completeness, post processing, I/O files verified, and etc.) ☒**Yes** ☐ **No**
	Comments:

[3] South Coast AQMD Risk Assessment Procedure for Rule 1401, 1401.1 and 212, Version 8.1, September 1, 2017, http://www.aqmd.gov/docs/default-source/permitting/rule-1401-risk-assessment/riskassessproc-v8-1.pdf

Detailed modeling review comments and notes:

The stack parameters and emission rates are provided below for reference.

Table 5 – Stack Locations and Dimensions

Equipment	Easting (m)	Northing (m)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)
CCGT 1	409449	3723148	3.66	45.7	6.10
CCGT 2	409474	3723182	3.66	45.7	6.10
AB	409438	3723236	3.66	24.4	0.91

Table 6 – Stack Parameters

Equipment	Load	Exhaust Temp (K)	Exit Velocity (m/s)
CCGT 1	44%	350	11.8
CCGT 2	44%	350	11.8
Auxiliary Boiler	100%	432	21.2

Table 7 – Emission Rates

Equipment	Annual NO_x		Annual $PM_{10}/PM_{2.5}$	
	Lbs/yr	g/s	Lbs/yr	g/s
CCGT 1 & CCGT 2 (Class I)	142,600[a]	2.0529	64,940	9.3489×10^{-1}
CCGT 1 & CCGT 2 (Class II and AAQS)	96,509[b]	1.39	64,940	9.3489×10^{-1}
Auxiliary Boiler[c]	1,313	1.8902×10^{-2}	1,392	2.0035×10^{-2}

[a] CCGT NO_2 emissions for Class I analysis is based on the maximum potential to emit.
[b] CCGT NO_2 emissions for Class II and AAQS analysis includes pre-project emissions of 73,409 lbs/year + 6,300 lb/yr (increase in non-cold start-up) + 16,800 lbs/year (16.8 lb/hr x 1,000 hr/yr increase). Baseline NO_2 emissions calculated as 8.38 lb/hr x 8,760 hrs/yr.
[c] Since the auxiliary boiler has no operating restrictions, it was assumed to operate for 8,760 hrs/yr.

In summary, the air dispersion modeling was conducted in accordance with District guidance and recommendations. Staff was able to replicate the applicant's results and found that the combined impact from the CCGTs and AB are not expected to cause an exceedance of the annual NAAQS or CAAQS for NO_2, PM_{10}, and $PM_{2.5}$. Therefore, any individual permit unit is not expected to cause a violation nor make significantly worse an existing violation of the NAAQS or CAAQS. Compliance with the modeling requirements in Rules 1303 and 2005 have been demonstrated.

The NO_2 and PM_{10} concentrations at Class I and Class II areas are expected to stay below the applicable SILs; therefore compliance with Rule 1703 has been demonstrated.

The HRA was conducted in accordance with South Coast AQMD's HRA guidance and recommendations. Staff was able to replicate the applicant's results and all health risks are below the applicable thresholds; therefore, compliance with Rule 1401 has been demonstrated.

Appendix M

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)

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.

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.

Appendix N

GHG BACT Analysis

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 ratio 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.

Carbon Capture Technology

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.

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 was developed for the combined 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 CO_2/net MWh.

Each combined cycle turbine will be subject to an emission limit of 873,035 tons CO_2 per year. Compliance will be based on a 12-month rolling average as determined by using emission factors and fuel usage.