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South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

June 13, 2014

Ms. Patricia Kelly, Project Manager
California Energy Commission
1516 Ninth Street, MS-2000
Sacramento, CA 95814

SUBJECT: Redondo Beach Energy Project (RBEP)
Facility Location: 1100 N. Harbor Dr., Redondo Beach, CA 90277

Dear Ms. Kelly:

The South Coast Air Quality Management District (SCAQMD) has received permit applications for the subject project. The applicant is proposing to replace four existing electric utility boiler generator Units 5, 6, 7, and 8 that are older, less efficient units and which have been in operation since the 1950's (Units 5 and 6) and 1960's (Units 7 and 8) with a new, more efficient gas turbine generating system. The new generating system will consist of three natural gas-fired Mitsubishi 501DA combined cycle gas turbine generators configured as a 3-on-1 power block with a steam turbine generator. The combined generating capacity of the RBEP will be 546.4 MW. This capacity replaces the generating capacity of the existing Unit 7 (480 MW) and Units 6 and 8 (66.4 MW of 655 MW total). AES Southland has proposed to use the surplus 588.6 MW from the shutdown of Units 6 and 8 to offset the repowering projects at AES Huntington Beach and AES Alamitos. The new RBEP will be equipped with air pollution control equipment, which consists of catalysts (selective catalytic reduction and oxidation catalysts). Additional new proposed equipment will include a 12,000 gallon aqueous ammonia storage tank and an oil water separator.

The SCAQMD has evaluated the permit applications and made a preliminary determination that the equipment will comply with all of the applicable requirements of air quality rules and regulations. Attached for your review and comment are the Preliminary Determination of Compliance (PDOC) and proposed Title V permit revision that include the SCAQMD's engineering analysis. Based on the emission potential, this project is subject to the public notice requirements specified in SCAQMD Rules 212 – Standards for Approving Permits and Issuing Public Notice, 1710 – Prevention of Significant Deterioration Analysis, Notice and Reporting, 1714 – Prevention of Significant Deterioration for Greenhouse Gases, and 3006 – Title V Public Participation.

We intend to issue the Final Determination of Compliance (FDOC) 1) upon completion of the 30-day public comment and review period and after all pertinent comments have been considered, and 2) after EPA's review of the Title V permit significant revision.

Please find enclosed a public notice for the subject project issued in accordance with SCAQMD Rules 212, 1710, 1714, and 3006. The public notice is also being published in a newspaper of general circulation in the vicinity of the project, and it is also being forwarded to other interested parties.

If you wish to provide comments or have any questions regarding this project, please contact Mr. Andrew Lee at (909) 396-2643 /alee@aqmd.gov.

Sincerely,

Mohsen Nazemi, P.E.
Deputy Executive Officer
Engineering and Compliance

MN:AYL:CDT:JTY:VL

Enclosures: Public Notice
Draft Facility Permit
PDOC

cc: Stephen O'Kane, w/o attachment

South Coast
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NOTICE OF INTENT TO ISSUE PERMITS
PURSUANT TO SCAQMD RULES 212, 1710, 1714, AND 3006

This notice is to inform you that the South Coast Air Quality Management District (SCAQMD) has received permit applications from AES Redondo Beach, LLC for the Redondo Beach Energy Project (RBEP) which will consist of the replacement of four existing older and less efficient large electric generating utility boilers with three new, more efficient electric generating gas turbines at Redondo Beach Generating Station in Redondo Beach. After a careful review and a detailed evaluation of the RBEP, SCAQMD has determined that the proposed project complies with all applicable federal, state and local air quality rules and regulations. Therefore, SCAQMD intends to issue Permits to Construct for the RBEP and to revise the Title V permit for this facility upon California Energy Commission's (CEC's) completion of the application for certification process and approval of the license for the RBEP. In addition, prior to issuance of the final Title V permit, SCAQMD is providing an opportunity for public comments on the SCAQMD's proposed decision.

The SCAQMD is the air pollution control agency for the four-county region including all of Orange County and non-desert parts of Los Angeles, Riverside and San Bernardino Counties. Anyone wishing to install or modify equipment that could control or be a source of air pollution within this region must first obtain a permit from the SCAQMD. Under certain circumstances, before a permit is granted, a public notice, such as this, is prepared by the SCAQMD. For this project, public notification is required in accordance with SCAQMD Rule 212(c)(2), Rule 212(g) and Rule 1710(b) because the emissions from the new gas turbines exceed the public notice thresholds for these rules. Public notification is also required by SCAQMD Rule 3006(a) and Rule 1714(e) because there will be a significant revision to the facility's existing Title V air permit and the RBEP is subject to a Prevention of Significant Deterioration (PSD) Permit due to its greenhouse gas emissions.

The SCAQMD has evaluated the permit applications listed below for the following facility and determined that the RBEP meets or will meet all applicable federal, state and SCAQMD air quality rules and regulations as described below:

FACILITY: AES Redondo Beach LLC
Facility ID No. 115536
1100 N. Harbor Dr.
Redondo Beach, CA 90277

CONTACT: Stephen O'Kane
Manager Sustainability and Regulatory Compliance
AES Southland
690 N. Studebaker Rd.
Long Beach, CA 90803

SCAQMD APPLICATION NUMBERS

Application Number	Equipment Description
545068	Mitsubishi 501DA Combined Cycle Gas Turbine Generator, Unit 03-A
545069	Mitsubishi 501DA Combined Cycle Gas Turbine Generator, Unit 03-B
545070	Mitsubishi 501DA Combined Cycle Gas Turbine Generator, Unit 03-C

545066	Air Pollution Control Equipment, SCR and CO Catalyst for Unit 03-A
545067	Air Pollution Control Equipment, SCR and CO Catalyst for Unit 03-B
545071	Air Pollution Control Equipment, SCR and CO Catalyst for Unit 03-C
545072	Aqueous Ammonia Storage Tank
549120	Oil Water Separator
545065	Title V/RECLAIM Significant Permit Revision

PROJECT DESCRIPTION

The proposed RBEP will replace the four existing electric utility boiler generator Units 5, 6, 7, and 8 that are older, less efficient units and which have been in operation since the 1950's (Units 5 and 6) and 1960's (Units 7 and 8) with a new, more efficient gas turbine generating system. The new generating system will consist of three natural gas-fired Mitsubishi 501DA combined cycle gas turbine generators configured as a 3-on-1 power block with a steam turbine generator. The combined generating capacity of the RBEP will be 546.4 MW. This capacity replaces the generating capacity of the existing Unit 7 (480 MW) and Units 6 and 8 (66.4 MW of 655 MW total). The surplus 588.6 MW from the shutdown of Units 6 and 8 will be used to offset the repowering projects at AES Huntington Beach and AES Alamitos. The new RBEP will be equipped with air pollution control equipment, which consists of catalysts (selective catalytic reduction and oxidation catalysts). Additional new proposed equipment will include a 12,000 gallon aqueous ammonia storage tank and an oil water separator.

EMISSIONS

During normal operation, the total potential maximum daily, monthly, and annual emissions of criteria pollutants from the operation of the new RBEP are estimated not to exceed the emission levels listed in the table below. In addition, the new RBEP will generate emissions of greenhouse gases (GHGs). The total quantity of GHGs is calculated using the global warming potential for each compound and expressed in an amount equivalent to Carbon Dioxide (CO_2) emissions (CO_2 equivalent). The emissions listed below are strictly from the new equipment and do not include any emission reductions associated with the removal from service of the existing electric utility boiler generator Units 5, 6, 7 and 8.

Pollutant	Max Potential Emissions (Tons)		
	Daily	Monthly	Annual
Nitrogen Oxides (NOx)	0.50	15.27	121.5
Carbon Monoxide (CO)	0.74	18.87	138.7
Volatile Organic Compounds (VOC)	0.37	11.10	82.3
Particulate Matter (diameter less than 10 microns, PM_{10} or diameter less than 2.5 microns, $PM_{2.5}$)	0.21	6.42	49.65
Sulfur Oxides (SOx)	0.08	2.37	6.45
Ammonia (NH3)	0.36	10.73	128.77
Carbon Dioxide equivalent ($CO_{2equivalent}$)	4774.85	143,245.38	1,718,944.60

The proposed RBEP will not result in an increase in the electrical generating capacity since the total electrical generating capacity of the new RBEP is offset by the generating capacity it replaces. SCAQMD Rule 1304(a)(2) provides an offset exemption for an electric utility boiler replacement project such as this project. Therefore, the applicant is not required to provide emission offsets for VOC, PM_{10}, and SOx. Also, the South Coast Air Basin meets and is in attainment with ambient air quality standards for CO, so no CO offsets are required. All of the NOx emissions from this facility have to be offset with emission credits that AES Redondo Beach, LLC either holds or purchases through the Regional Clean Air Incentive's Market (RECLAIM) in the form of RECLAIM Trading Credits (RTCs). Finally, the total facility's potential emissions (the proposed new RBEP) of $PM_{2.5}$ will be limited to less than 100 tons per year, therefore the new RBEP will not trigger the threshold for $PM_{2.5}$ offset requirements as per SCAQMD Rule 1325. The NOx RTCs are required to be provided by AES Redondo Beach, LLC prior to the RBEP commencing its operation in accordance with SCAQMD RECLAIM Rule 2005.

As a result of burning natural gas in the gas turbines, emissions from the proposed project also contain small quantities of pollutants that are considered air toxics under SCAQMD Rule 1401-New Source Review of Toxic Air Contaminants. Therefore, a health risk assessment (HRA) has been performed for the RBEP. The health risk assessment uses health protective assumptions in estimating maximum risk to an individual person. Even assuming this health protective condition, the evaluation shows that the maximum individual cancer risk (MICR) increase from each gas turbine, even without considering the emission reductions from old equipment being replaced, is less than one-in-one million and in compliance with SCAQMD's risk thresholds listed in Rule 1401. Also, acute and chronic indices, which measure non-cancer health impacts, are less than one. According to the state health experts, a hazard index of one or less means that the surrounding community including the most sensitive individuals such as very young children and the elderly will not experience any adverse health impacts due to exposure to these emissions. These levels of estimated risk are below the threshold limits of SCAQMD Rule 1401 (d) established for new or modified sources. The HRA results are shown in the table below:

Health Risks

	MICR (in a million)		Non-Cancer Hazard Index	
Equipment	Resident	Worker	Chronic	Acute
Gas Turbine No. 03-A	0.69	0.13	0.00218	0.0206
Gas Turbine No. 03-B	0.66	0.12	0.00206	0.0144
Gas Turbine No. 03-C	0.65	0.11	0.00205	0.0116
Rule 1401 Limit	1.0		1.0	

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) FOR CRITERIA POLLUTANTS

The South Coast Air Basin is in attainment with the national ambient air quality standards for Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), Carbon Monoxide (CO) and Particulate Matter with aerodynamic diameter less than 10 microns (PM10); therefore, the NO_2, SO_2, CO, and PM10 emissions from the project are subject to the SCAQMD's Prevention of Significant Deterioration (PSD) regulation (Regulation XVII).

The Redondo Beach Generating Station is classified as a major stationary source, and the estimated maximum project emissions of NO_2 of 31.91 micro grams per cubic meter ($\mu g/m^3$) exceed the PSD significance impact level (SIL) of 7.5 $\mu g/m^3$. Therefore, an incremental modeling analysis is required to demonstrate that the proposed RBEP does not cause, or make significantly worse an existing, 1-hour NO_2 violation of the national ambient air quality standard (NAAQS). The results of the incremental modeling analysis show that the peak contribution from the proposed RBEP is 142.62 $\mu g/m^3$ and therefore does not result in a violation of the existing 1-hour NO_2 NAAQS of 188 $\mu g/m^3$.

Also based on the result of a screening analysis of the potential impacts to Class I wilderness areas, the RBEP will not impact visibility on the nearest Class I area (i.e., San Gabriel Wilderness). Based on all of these analysis and evaluations, the SCAQMD has determined that the proposed RBEP is expected to comply with all PSD requirements for criteria pollutants.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) FOR GREENHOUSE GASES

Based on the proposed RBEP maximum potential greenhouse gas (GHG) emissions, the proposed project is subject to preconstruction review for GHGs. SCAQMD staff has evaluated the GHG emissions from the RBEP for compliance determination with applicable federal, state, and local air quality requirements. The RBEP is found to comply with Rule 1714 BACT requirements for GHG emissions through the use of energy efficient gas turbines.

Based on the result of our detailed analysis and evaluation, the SCAQMD has determined that the RBEP complies with all applicable federal, state and SCAQMD air quality Rules and Regulations and, therefore, SCAQMD intends to issue the Permits to Construct for the equipment described above. In addition, prior to issuance of a final permit, SCAQMD is providing an opportunity for a 30-day public comment period and an EPA review period. SCAQMD will consider issuance of the final permit only after all pertinent public and EPA comments, if any, have been received and considered, and upon CEC's completion of the Application for Certification process and approval of the license for the RBEP.

This facility is classified as a federal Title IV (Acid Rain) and Title V facility. **Pursuant to SCAQMD Rule 3006 – Public Participation, any person may request a proposed permit hearing on an application for an initial, renewal, or significant revision to a Title V permit by filing with the Executive Officer a complete Hearing Request Form (Form 500G) for a proposed hearing no later than July 2, 2014.** This form is available on the SCAQMD website at http://www.aqmd.gov/docs/default-source/grants/500-g-form.pdf?sfvrsn , or alternatively, the form can be made available by contacting Ms. Vicky Lee at the e-mail and telephone number listed below. In order for a request for a public hearing to be valid, the request must comply with the requirements of SCAQMD Rule 3006 (a)(1)(F). On or before the date the request is filed, the person requesting a proposed permit hearing must also send by first class mail a copy of the request to the facility address and contact person listed above.

The proposed permits and other information are available for public review at the SCAQMD's headquarters in Diamond Bar, and at the Redondo Beach Public Library, 303 N. Pacific Coast Highway, Redondo Beach, CA 90277. Additional information including the facility owner's compliance history submitted to the SCAQMD pursuant to California Health and Safety Code Section 42336, or otherwise known to the SCAQMD, based on credible information, is available at the SCAQMD for public review by contacting Ms. Vicky Lee (vlee1@aqmd.gov), Engineering and Compliance, South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, CA 91865-4182, (909) 396-2284. A copy of the draft Permits to Construct can also be viewed at http://www3.aqmd.gov/webappl/PublicNotices2/. Anyone wishing to comment on the air quality elements of the permits must submit comments in writing to the SCAQMD at the above address, attention Mr. Andrew Lee. **Comments must be received no later than July 17, 2014.** If you are concerned primarily about zoning decisions and the process by which the facility has been sited in this location, contact the local city or county planning department for the city or unincorporated county in which the facility is located. For your general information, anyone experiencing air quality problems such as dust or odor can telephone in a complaint to the SCAQMD 24 hours a day by calling toll free 1-800-CUT-SMOG (1-800-288-7664).

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 5: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, AQUEOUS AMMONIA 19 PERCENT, 12000 GALS; DIAMETER: 12 FT ; LENGTH: 15 FT A/N:	D87				C157.1, E144.1, E193.3
Process 10: INTERNAL COMBUSTION - POWER GENERATION					

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

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Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
GAS TURBINE, NO. 03-A, COMBINED CYCLE, NATURAL GAS, MITSUBISHI POWER SYSTEMS AMERICAS, MODEL 501DA, 1492 MMBTU/HR HHV AT 33 F, WITH DRY LOW-NOX COMBUSTOR WITH A/N:	D88	C93	NOX: MAJOR SOURCE**	**CO**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **CO**: 2000 PPMV (5) **[RULE 407, 4-2-1982]**; **NOX**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**; **NOX**: 8.88 LBS/MMSCF NATURAL GAS (1A) **[RULE 2012, 5-6-2005]**; **NOX**: 13.08 LBS/MMSCF NATURAL GAS (1) **[RULE 2012, 5-6-2005]**; **NOX**: 25 PPMV NATURAL GAS (8) **[40CFR 60 Subpart KKKK, 7-6-2006]**; **PM10**: 0.01 GRAINS/SCF (5A) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF (5) **[RULE 409, 8-7-1981]**; **PM10**: 4.5 LBS/HR NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002;* **RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **PM10**: 11 LBS/HR (5B) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) **[40CFR 72 - Acid Rain Provisions, 11-24-1997]**; **SO2**: 0.06 LBS/MMBTU NATURAL GAS (8) **[40CFR 60 Subpart**	A63.1, A99.1, A99.2, A195.5, A195.6, A195.7, A327.1, B61.4, C1.5, C1.6, D29.1, D29.2, D82.1, D82.2, E193.3, E193.4, E193.5, E193.6, E193.7, E193.8, E193.9, I297.1, K40.2, K67.6

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

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The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
GENERATOR, CTG NO. 03-A, 131.9 MW GROSS AT 33 F HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG) NO. 03-A GENERATOR, STEAM TURBINE GENERATOR (STG), NO. 03-ST1, 150.7 MW GROSS AT 33 F, COMMON WITH HRSG NOS. 03-B AND 03-C				**KKKK, 7-6-2006**]; VOC: 2 PPMV NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1) -BACT, 12-6-2002*]	

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(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
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Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
BURNER, DUCT, NATURAL GAS, COEN/JOHN ZINK, MODEL LDRW, OR EQUIVALENT, SERVING HRSG NO. 03-A, 507 MMBTU/HR A/N:	D92	C93	NOX: MAJOR SOURCE**	CO: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **CO**: 2000 PPMV (5) **[RULE 407, 4-2-1982]**; **NOX**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**; **NOX**: 8.88 LBS/MMSCF NATURAL GAS (1A) **[RULE 2012, 5-6-2005]**; **NOX**: 13.08 LBS/MMSCF NATURAL GAS (1) **[RULE 2012, 5-6-2005]**; **NOX**: 25 PPMV NATURAL GAS (8) **[40CFR 60 Subpart KKKK, 7-6-2006]**; **PM10**: 0.01 GRAINS/SCF (5A) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF (5) **[RULE 409, 8-7-1981]**; **PM10**: 5 LBS/HR NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002;* **RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **PM10**: 11 LBS/HR (5B) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) **[40CFR 72 - Acid Rain Provisions, 11-24-1997]**; **SO2**: 0.06 LBS/MMBTU NATURAL GAS (8) **[40CFR 60 Subpart**	I297.2

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(3) Denotes RECLAIM concentration limit; (4) Denotes BACT emission limit
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Process 10: INTERNAL COMBUSTION - POWER GENERATION					
				KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	
CO OXIDATION CATALYST, NO. 03-A, JOHNSON MATTHEY, MODEL SC42, OR EQUIVALENT, CATALYST VOLUME: 203 CUBIC FEET A/N:	C93	D88 D92 C94			
SELECTIVE CATALYTIC REDUCTION, NO. 03-A, HALDOR TOPSOE, MODEL DNX GT-201, OR EQUIVALENT, 2804 CU.FT. WITH A/N: AMMONIA INJECTION, AQUEOUS AMMONIA	C94	C93 S96		NH3: 5 PPMV (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1)-BACT, 12-6-2002*]	A195.8, D12.8, D12.9, D12.10, D29.3, E179.3, E179.4, E193.3
STACK, TURBINE NO. 03-A, HEIGHT: 140 FT ; DIAMETER: 18 FT A/N:	S96	C94			

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(3)	Denotes RECLAIM concentration limit	(4)	Denotes BACT emission limit
(5) (5A) (5B)	Denotes command and control emission limit	(6)	Denotes air toxic control rule limit
(7)	Denotes NSR applicability limit	(8) (8A) (8B)	Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9)	See App B for Emission Limits	(10)	See section J for NESHAP/MACT requirements

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Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
GAS TURBINE, NO. 03-B, COMBINED CYCLE, NATURAL GAS, MITSUBISHI POWER SYSTEMS AMERICAS, MODEL 501DA, 1492 MMBTU/HR HHV AT 33 F, WITH DRY LOW-NOX COMBUSTOR WITH A/N:	D98	C103	NOX: MAJOR SOURCE**	**CO**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **CO**: 2000 PPMV (5) **[RULE 407, 4-2-1982]**; **NOX**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**; **NOX**: 8.88 LBS/MMSCF NATURAL GAS (1A) **[RULE 2012, 5-6-2005]**; **NOX**: 13.08 LBS/MMSCF NATURAL GAS (1) **[RULE 2012, 5-6-2005]**; **NOX**: 25 PPMV NATURAL GAS (8) **[40CFR 60 Subpart KKKK, 7-6-2006]**; **PM10**: 0.01 GRAINS/SCF (5A) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF (5) **[RULE 409, 8-7-1981]**; **PM10**: 4.5 LBS/HR NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002;* **RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **PM10**: 11 LBS/HR (5B) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) **[40CFR 72 - Acid Rain Provisions, 11-24-1997]**; **SO2**: 0.06 LBS/MMBTU NATURAL GAS (8) **[40CFR 60 Subpart**	A63.1, A99.1, A99.2, A195.5, A195.6, A195.7, A327.1, B61.4, C1.5, C1.6, D29.1, D29.2, D82.1, D82.2, E193.3, E193.4, E193.5, E193.6, E193.7, E193.8, E193.9, I297.3, K40.2, K67.6

* (1) (1A) (1B) Denotes RECLAIM emission factor — (2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit — (4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit — (6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit — (8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits — (10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
GENERATOR, CTG NO. 03-B, 131.9 MW GROSS AT 33 F HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG) NO. 03-B GENERATOR, STEAM TURBINE GENERATOR (STG), NO. 03-ST1, 150.7 MW GROSS AT 33 F, COMMON WITH HRSG NOS. 03-A AND 03-C				**KKKK, 7-6-2006]**; **VOC**: 2 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	

* (1) (1A) (1B)	Denotes RECLAIM emission factor	(2) (2A) (2B)	Denotes RECLAIM emission rate
(3)	Denotes RECLAIM concentration limit	(4)	Denotes BACT emission limit
(5) (5A) (5B)	Denotes command and control emission limit	(6)	Denotes air toxic control rule limit
(7)	Denotes NSR applicability limit	(8) (8A) (8B)	Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9)	See App B for Emission Limits	(10)	See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
BURNER, DUCT, NATURAL GAS, COEN/JOHN ZINK, MODEL LDRW, OR EQUIVALENT, SERVING HRSG NO. 03-B, 507 MMBTU/HR A/N:	D102	C103	NOX: MAJOR SOURCE**	**CO**: 2 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **CO**: 2000 PPMV (5) [**RULE 407, 4-2-1982**]; **NOX**: 2 PPMV NATURAL GAS (4) [**RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011**]; **NOX**: 8.88 LBS/MMSCF NATURAL GAS (1A) [**RULE 2012, 5-6-2005**]; **NOX**: 13.08 LBS/MMSCF NATURAL GAS (1) [**RULE 2012, 5-6-2005**]; **NOX**: 25 PPMV NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **PM10**: 0.01 GRAINS/SCF (5A) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF (5) [**RULE 409, 8-7-1981**]; **PM10**: 5 LBS/HR NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002;* **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; **PM10**: 11 LBS/HR (5B) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) [**40CFR 72 - Acid Rain Provisions, 11-24-1997**]; **SO2**: 0.06 LBS/MMBTU NATURAL GAS (8) [**40CFR 60 Subpart**	I297.4

* (1) (1A) (1B) Denotes RECLAIM emission factor — (2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit — (4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit — (6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit — (8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits — (10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
				KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	
CO OXIDATION CATALYST, NO. 03-B, JOHNSON MATTHEY, MODEL SC42, OR EQUIVALENT, CATALYST VOLUME: 203 CUBIC FEET A/N:	C103	D98 D102 C104			
SELECTIVE CATALYTIC REDUCTION, NO. 03-B, HALDOR TOPSOE, MODEL DNX GT-201, OR EQUIVALENT, 2804 CU.FT. WITH A/N: AMMONIA INJECTION, AQUEOUS AMMONIA	C104	C103 S106		**NH3**: 5 PPMV (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1)-BACT, 12-6-2002*]	A195.8, D12.8, D12.9, D12.10, D29.3, E179.3, E179.4, E193.3
STACK, TURBINE NO. 03-B, HEIGHT: 140 FT ; DIAMETER: 18 FT A/N:	S106	C104			

* (1) (1A) (1B) Denotes RECLAIM emission factor
(3) Denotes RECLAIM concentration limit
(5) (5A) (5B) Denotes command and control emission limit
(7) Denotes NSR applicability limit
(9) See App B for Emission Limits
(2) (2A) (2B) Denotes RECLAIM emission rate
(4) Denotes BACT emission limit
(6) Denotes air toxic control rule limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
GAS TURBINE, NO. 03-C, COMBINED CYCLE, NATURAL GAS, MITSUBISHI POWER SYSTEMS AMERICAS, MODEL 501DA, 1492 MMBTU/HR HHV AT 33 F, WITH DRY LOW- NOX COMBUSTOR WITH A/N:	D107	C112	NOX: MAJOR SOURCE**	**CO**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **CO**: 2000 PPMV (5) **[RULE 407, 4-2-1982]**; **NOX**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**; **NOX**: 8.88 LBS/MMSCF NATURAL GAS (1A) **[RULE 2012, 5-6-2005]**; **NOX**: 13.08 LBS/MMSCF NATURAL GAS (1) **[RULE 2012, 5-6-2005]**; **NOX**: 25 PPMV NATURAL GAS (8) **[40CFR 60 Subpart KKKK, 7-6-2006]**; **PM10**: 0.01 GRAINS/SCF (5A) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF (5) **[RULE 409, 8-7-1981]**; **PM10**: 4.5 LBS/HR NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002;* **RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **PM10**: 11 LBS/HR (5B) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) **[40CFR 72 - Acid Rain Provisions, 11-24-1997]**; **SO2**: 0.06 LBS/MMBTU NATURAL GAS (8) **[40CFR 60 Subpart**	A63.1, A99.1, A99.2, A195.5, A195.6, A195.7, A327.1, B61.4, C1.5, C1.6, D29.1, D29.2, D82.1, D82.2, E193.3, E193.4, E193.5, E193.6, E193.7, E193.8, E193.9, I297.5, K40.2, K67.6

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
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(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
GENERATOR, CTG NO. 03-C, 131.9 MW GROSS AT 33 F HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG) NO. 03-C GENERATOR, STEAM TURBINE GENERATOR (STG), NO. 03-ST1, 150.7 MW GROSS AT 33 F, COMMON WITH HRSG NOS. 03-A AND 03-B				**KKKK, 7-6-2006**]; VOC: 2 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	

* (1) (1A) (1B) Denotes RECLAIM emission factor
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(5) (5A) (5B) Denotes command and control emission limit
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(9) See App B for Emission Limits
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FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

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The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
BURNER, DUCT, NATURAL GAS, COEN/JOHN ZINK, MODEL LDRW, OR EQUIVALENT, SERVING HRSG NO. 03-C, 507 MMBTU/HR A/N:	D111	C112	NOX: MAJOR SOURCE**	**CO**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **CO**: 2000 PPMV (5) **[RULE 407, 4-2-1982]**; **NOX**: 2 PPMV NATURAL GAS (4) **[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**; **NOX**: 8.88 LBS/MMSCF NATURAL GAS (1A) **[RULE 2012, 5-6-2005]**; **NOX**: 13.08 LBS/MMSCF NATURAL GAS (1) **[RULE 2012, 5-6-2005]**; **NOX**: 25 PPMV NATURAL GAS (8) **[40CFR 60 Subpart KKKK, 7-6-2006]**; **PM10**: 0.01 GRAINS/SCF (5A) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF (5) **[RULE 409, 8-7-1981]**; **PM10**: 5 LBS/HR NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002;* **RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**; **PM10**: 11 LBS/HR (5B) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) **[40CFR 72 - Acid Rain Provisions, 11-24-1997]**; **SO2**: 0.06 LBS/MMBTU NATURAL GAS (8) **[40CFR 60 Subpart**	I297.6

* (1) (1A) (1B) Denotes RECLAIM emission factor (2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit (4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit (6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit (8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits (10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 10: INTERNAL COMBUSTION - POWER GENERATION					
				KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	
CO OXIDATION CATALYST, NO. 03-C, JOHNSON MATTHEY, MODEL SC42, OR EQUIVALENT, CATALYST VOLUME: 203 CUBIC FEET A/N:	C112	D107 D111 C113			
SELECTIVE CATALYTIC REDUCTION, NO. 03-C, HALDOR TOPSOE, MODEL DNX GT-201, OR EQUIVALENT, 2804 CU.FT. WITH A/N: AMMONIA INJECTION, AQUEOUS AMMONIA	C113	C112 S115		**NH3**: 5 PPMV (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1)-BACT, 12-6-2002*]	A195.8, D12.8, D12.9, D12.10, D29.3, E179.3, E179.4, E193.3
STACK, TURBINE NO. 03-C, HEIGHT: 140 FT ; DIAMETER: 18 FT A/N:	S115	C113			
Process 11: OIL/WATER SEPARATION					
OIL WATER SEPARATOR, NO. OWS01, ABOVEGROUND, 3000 GALS, WIDTH: 5 FT ; HEIGHT: 5 FT ; LENGTH: 18 FT A/N:	D116				E193.3

* (1) (1A) (1B) Denotes RECLAIM emission factor
(2) (2A) (2B) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emission limit
(5) (5A) (5B) Denotes command and control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See section J for NESHAP/MACT requirements

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: DEVICE ID INDEX

The following sub-section provides an index to the devices that make up the facility description sorted by device ID.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: DEVICE ID INDEX

Device Index For Section H			
Device ID	**Section H Page No.**	**Process**	**System**
D87	1	5	0
D88	3	10	0
D92	5	10	0
C93	5	10	0
C94	5	10	0
S96	5	10	0
D98	7	10	0
D102	9	10	0
C103	9	10	0
C104	9	10	0
S106	9	10	0
D107	11	10	0
D111	13	10	0
C112	13	10	0
C113	13	10	0
S115	13	10	0
D116	13	11	0

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

FACILITY CONDITIONS

F9.1 Except for open abrasive blasting operations, the operator shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated No.1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

(b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

[**RULE 401, 3-2-1984;** RULE 401, 11-9-2001]

F14.1 The operator shall not use fuel oil containing sulfur compounds in excess of 0.05 percent by weight.

[**RULE 431.2, 5-4-1990;** RULE 431.2, 9-15-2000]

F14.2 The operator shall not purchase diesel fuel containing sulfur compounds in excess of 15 ppm by weight as supplied by the supplier.

This condition shall become effective on or after June 1, 2004.

[RULE 431.2, 9-15-2000]

F18.1 Acid Rain SO2 Allowance Allocation for affected units are as follows:

Device ID	Boiler ID	Contaminant	Tons in any year
20	Boiler No. 5	SO2	126
23	Boiler No. 6	SO2	103
6	Boiler No. 7	SO2	483
8	Boiler No. 8	SO2	496

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

72	Boiler No. 17	SO2	6

a). The allowance allocation(s) shall apply to calendar years 2010 and beyond.

b). The number of allowances allocated to Phase II affected units by U.S. EPA may change in a 1998 revision to 40CFR73 Tables 2,3, and 4. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO2 allowance allocations identified in this permit (see 40 CFR 72.84)

[40CFR 73 Subpart B, 1-11-1993]

F21.1 Acid Rain SO2 Allowance Allocation for retired units are as follows:

Boiler ID	Contaminant	Tons in year
Boiler No. 11	SO2	4
Boiler No. 12	SO2	2
Boiler No. 13	SO2	4
Boiler No. 14	SO2	4
Boiler No. 15	SO2	3
Boiler No. 16	SO2	5

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

a). The allowance allocation(s) shall apply to calendar years 2010 and beyond.

b). The number of allowances allocated to Phase II affected units by U.S. EPA may change in a 1998 revision to 40CFR73 Tables 2,3, and 4. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO2 allowance allocations identified in this permit (see 40 CFR 72.84).

c). A unit exempted under 40CFR72.8 shall not emit any sulfur dioxide starting on the date it is exempted.

d). The owners and operators of a unit exempted under 40CFR72.8 shall comply with monitoring requirements in accordance with part 75 and will be allocated allowances in accordance with 40CFR73.

e). A unit exempted under 40CFR73 shall not resume operation unless the designated representative of the source that includes the unit submits an Acid Rain permit application for the unit not less than 24 months prior to the later of January 1, 2000, or the date the unit is to resume operation. On the earlier of the date the written exemption expires or the date an Acid Rain permit application is submitted or is required to be submitted under this paragraph, the unit shall no longer be exempted and shall be subject to all requirements of 40CFR72.

[40CFR 73 Subpart B, 1-11-1993]

F24.1 Accidental release prevention requirements of Section 112(r)(7):

a). The operator shall comply with the accidental release prevention requirements pursuant to 40 CFR Part 68 and shall submit to the Executive Officer, as a part of an annual compliance certification, a statement that certifies compliance with all of the requirements of 40 CFR Part 68, including the registration and submission of a risk management plan (RMP).

b). The operator shall submit any additional relevant information requested by the Executive Officer or designated agency.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

[40CFR 68 - Accidental Release Prevention, 5-24-1996]

F52.1 This facility is subject to the applicable requirements of the following rules or regulation(s):

The facility shall submit a detailed retirement plan for the permanent shutdown of Boilers No. 6 (Device D23), No. 7 (Device D6), and No. 8 (Device D8) describing in detail the steps and schedule that will be taken to render Boilers Nos. 6, 7, and 8 permanently inoperable. The retirement plan shall be submitted to SCAQMD within 60 days after Permits to Construct for Gas Turbines No. 03-A (Device D88), 03-B (Device D98), and 03-C (Device D107) are issued.

The retirement plan must be approved in writing by SCAQMD. AES shall not commence any construction of the Redondo Beach Energy Project including Gas Turbines Nos. 03-A, 03-B, 03-C, Steam Turbine No. 03-ST1, and SCR/CO catalysts for Gas Turbine Nos. 03-A, 03-B, 03-C, before the retirement plan is approved in writing by SCAQMD. If SCAQMD notifies AES that the plan is not approvable, AES shall submit a revised plan addressing SCAQMD's concerns within 30 days.

Within 30 calendar days of actual shutdown but no later than December 31, 2018, AES shall provide SCAQMD with a notarized statement that Boilers No. 6, 7, and 8 are permanently shut down and that any re-start or operation of the boilers shall require new Permits to Construct and be subject to all requirements of nonattainment new source review and the prevention of significant deterioration program.

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers No. 6, 7, and 8, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 31, 2018.

AES shall cease operation of Boilers No. 6 (Device D23), No. 7 (Device D6), and No. 8 (D8) within 90 calendar days of the first fire of Gas Turbines No. 03-A (Device D88), No. 03-B (Device D98), or No. 03-C (Device D107).

[RULE 1304(a)-Modeling and Offset Exemption, 6-14-1996; RULE 1313(d), 12-7-1995]

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

F52.2 This facility is subject to the applicable requirements of the following rules or regulation(s):

For all circuit breakers at the facility utilizing SF6, including the circuit breakers serving Gas Turbines No. 03-A, 03-B, and 03-C, Steam Turbine Generator No. 03-ST1, and the electrical connection line, the operator shall install, operate, and maintain enclosed-pressure SF6 circuit breakers with a maximum annual leakage rate of 0.5 percent by weight. The circuit breakers shall be equipped with a 10 percent by weight leak detection system.

The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations shall be maintained on site.

The total CO2e emissions from all circuit breakers shall not exceed 17.8 tons per calendar year.

[RULE 1714, 12-10-2012]

DEVICE CONDITIONS

A. Emission Limits

A63.1 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
VOC	Less than or equal to 14121 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 4278 LBS IN ANY CALENDAR MONTH
SOX	Less than or equal to 1583 LBS IN ANY CALENDAR MONTH

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The operator shall comply with the terms and conditions set forth below:

For the purposes of this condition, the above emission limits shall be based on the emissions from a single turbine.

The turbine shall not commence with normal operation until the commissioning process has been completed. Normal operation commences when the turbine is able to supply electrical energy to the power grid as required under contract with the relevant entities. The SCAQMD shall be notified in writing once the commissioning process for each turbine is completed.

Normal operation may commence in the same calendar month as the completion of the commissioning process provided the turbine is in compliance with the above emission limits.

The operator shall calculate the monthly emissions for VOC, PM10, and SOx using the equation below.

Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)

For commissioning, the emission factors shall be as follows: VOC, 22.29 lb/mmcf; PM10, 4.63 lb/mmcf; and SOx, 1.68 lb/mmcf.

For normal operation, the emission factors shall be as follows: VOC, 6.45 lb/mmcf; PM10, 3.73 lb/mmcf; and SOx, 1.38 lb/mmcf.

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

Each turbine shall not be operated more than 6835 hours (including 470 hours with duct firing) in any calendar year, including startups and shutdowns, but not commissioning.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

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The operator shall comply with the terms and conditions set forth below:

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1304.1, 9-6-2013; **RULE 1703 - PSD Analysis, 10-7-1988**]

[Devices subject to this condition : D88, D98, D107]

A99.1 The 13.08 LBS/MMSCF NOX emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[RULE 2012, 5-6-2005]

[Devices subject to this condition : D88, D98, D107]

A99.2 The 8.88 LBS/MMCF NOX emission limit(s) shall only apply during the interim period after commissioning to report RECLAIM emissions.

[RULE 2012, 5-6-2005]

[Devices subject to this condition : D88, D98, D107]

A195.5 The 2.0 PPMV NOX emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, cold startups, warm startups, hot startups, and shutdown periods.

[RULE 1703 - PSD Analysis, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition : D88, D98, D107]

A195.6 The 2.0 PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, cold startups, warm startups, hot startups, and shutdown periods.

[RULE 1703 - PSD Analysis, 10-7-1988]

[Devices subject to this condition : D88, D98, D107]

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The operator shall comply with the terms and conditions set forth below:

A195.7 The 2.0 PPMV VOC emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, cold startups, warm startups, hot startups, and shutdown periods.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : D88, D98, D107]

A195.8 The 5.0 PPMV NH3 emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen.

The operator shall calculate and continuously record the NH3 slip concentration using the following equation:

NH3 (ppmvd) = [a-b*(c*1.2)/1,000,000]*1,000,000/b, where:

a = NH3 injection rate (lb/hr)/17(lb/lb-mol)

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

c = change in measured NOx across the SCR (ppmvd at 15% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to within plus or minus 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedure shall be in effect no later than 90 days after initial startup of the turbine.

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : C94, C104, C113]

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The operator shall comply with the terms and conditions set forth below:

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

[**RULE 475, 10-8-1976;** RULE 475, 8-7-1978]

[Devices subject to this condition : D88, D98, D107]

B. Material/Fuel Type Limits

B61.4 The operator shall not use natural gas containing the following specified compounds:

Compound	range	grain per 100 scf
H2S	greater than	0.25

This concentration limit is an annual average based on monthly samples 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 1304.1, 9-6-2013]

[Devices subject to this condition : D88, D98, D107]

C. Throughput or Operating Parameter Limits

C1.5 The operator shall limit the number of start-ups to no more than 90 in any one calendar month.

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The operator shall comply with the terms and conditions set forth below:

The number of cold startups shall not exceed 5 in any calendar month, the number of warm startups shall not exceed 25 in any calendar month, and the number of hot starts shall not exceed 60 in any calendar month, with no more than 3 startups in any one day.

The number of cold startups shall not exceed 24 in any calendar year, the number of warm startups shall not exceed 150 in any calendar year, and the number of hot startups shall not exceed 450 in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the steam turbine has been shut down for more than 49 hours. A cold startup shall not exceed 90 minutes. The NOx emissions from a cold startup shall not exceed 28.7 lbs. The CO emissions from a cold startup shall not exceed 115.9 lbs. The VOC emissions from a cold startup shall not exceed 27.9 lbs.

For the purposes of this condition, a warm startup is defined as a startup which occurs after the steam turbine has been shut down between 9 and 49 hours, inclusive. A warm startup shall not exceed 32.5 minutes. The NOx emissions from a warm startup shall not exceed 16.6 lbs. The CO emissions from a warm startup shall not exceed 46.0 lbs. The VOC emissions from a warm startup shall not exceed 21.0 lbs.

For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 9 hours. A hot startup shall not exceed 32.5 minutes. The NOx emissions from a hot startup shall not exceed 16.6 lbs. The CO emissions from a hot startup shall not exceed 33.6 lbs. The VOC emissions from a hot startup shall not exceed 20.4 lbs.

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

The operator shall maintain records in a manner approved by the District, to demonstrate compliance with this condition.

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The operator shall comply with the terms and conditions set forth below:

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2012, 5-6-2005**]

[Devices subject to this condition : D88, D98, D107]

C1.6 The operator shall limit the number of shut-downs to no more than 90 in any one calendar month.

The number of shutdowns shall not exceed 624 in any calendar year.

Each shutdown shall not exceed 10 minutes. The NOx emissions from a shutdown event shall not exceed 9.0 lbs. The CO emissions from a shutdown event shall not exceed 45.3 lbs. The VOC emissions from a shutdown event shall not exceed 31.0 lbs.

The operator shall maintain records in a manner approved by the District, to demonstrate compliance with this condition.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2012, 5-6-2005**]

[Devices subject to this condition : D88, D98, D107]

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

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : D87]

D. Monitoring/Testing Requirements

D12.8 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).

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The operator shall comply with the terms and conditions set forth below:

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The operator shall maintain the ammonia injection rate between 11.8 and 33 gallons per hour.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**

[Devices subject to this condition : C94, C104, C113]

D12.9 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 400 degrees F and 700 degrees F, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**

[Devices subject to this condition : C94, C104, C113]

D12.10 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

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The operator shall comply with the terms and conditions set forth below:

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure differential shall be between 1.5 and 3.5 inches water column.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**

[Devices subject to this condition : C94, C104, C113]

D29.1 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District method 100.1	1 hour	Outlet of the SCR serving this equipment
SOX emissions	Approved District method	District-approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	Approved District method	District-approved averaging time	Outlet of the SCR serving this equipment
PM2.5	EPA Method 201A and 202	4 hours	Outlet of the SCR serving this equipment
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

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The operator shall comply with the terms and conditions set forth below:

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

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

The test shall be conducted with a District approved source test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

For gas turbines only the VOC test shall use the following method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to having less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the canisters temperature when extracting samples for analysis is not to be below 70 deg F.

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results must be reported with two significant digits.

The sampling time for the PM2.5 tests shall be 4 hours or longer as necessary to obtain a measureable amount of sample.

The test shall be conducted when this equipment is operating at loads of 70 and 100 percent of maximum load without duct burner firing, and 100 percent of maximum load with duct burner firing.

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The operator shall comply with the terms and conditions set forth below:

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**

[Devices subject to this condition : D88, D98, D107]

D29.2 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	Approved District method	District-approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	Approved District method	District-approved averaging time	Outlet of the SCR serving this equipment

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The operator shall comply with the terms and conditions set forth below:

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

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 when this equipment is operating at 100 percent of maximum load without duct burner firing, and 100 percent of maximum load with duct burner firing.

For gas turbines only the VOC test shall use the following method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to having less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the canisters temperature when extracting samples for analysis is not to be below 70 deg F.

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results must be reported with two significant digits.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**

[Devices subject to this condition : D88, D98, D107]

D29.3 The operator shall conduct source test(s) for the pollutant(s) identified below.

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

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The operator shall comply with the terms and conditions set forth below:

NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

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

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : C94, C104, C113]

D82.1 The operator shall install and maintain a CEMS to measure the following parameters:

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The operator shall comply with the terms and conditions set forth below:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

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

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) 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)/10E+06], where:

1. K = 7.267 *10E-08 (lb/scf)/ppm
2. Cco = Average of four consecutive 15 min. average CO concentrations, ppm
3. Fd = 8710 dscf/MMBTU natural gas
4. %O2 d = Hourly average % by volume O2 dry, corresponding to Cco
5. Qg = Fuel gas usage during the hour, scf/hr
6. HHV = Gross high heating value of fuel gas, BTU/scf

[RULE 1703 - PSD Analysis, 10-7-1988]

[Devices subject to this condition : D88, D98, D107]

D82.2 The operator shall install and maintain a CEMS to measure the following parameters:

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The operator shall comply with the terms and conditions set forth below:

NOX concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

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

[RULE 1703 - PSD Analysis, 10-7-1988; RULE 2005, 6-3-2011; RULE 2012, 5-6-2005]

[Devices subject to this condition : D88, D98, D107]

E. Equipment Operation/Construction Requirements

E144.1 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : D87]

E179.3 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D 12- 8

Condition Number D 12- 9

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**

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The operator shall comply with the terms and conditions set forth below:

[Devices subject to this condition : C94, C104, C113]

E179.4 For the purpose of the following condition number(s), continuously record shall be defined as as recording at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number D 12-10

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**

[Devices subject to this condition : C94, C104, C113]

E193.3 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-03 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition : D87, D88, C94, D98, C104, D107, C113, D116]

E193.4 The operator shall operate and maintain this equipment according to the following requirements:

The commissioning period shall not exceed 491 hours of operation for each turbine from the date of initial turbine start-up. Three turbines may be commissioned at the same time.

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

The operator shall provide the SCAQMD with written notification of the initial startup date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from SCAQMD.

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The operator shall comply with the terms and conditions set forth below:

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**

[Devices subject to this condition : D88, D98, D107]

E193.5 The operator shall operate and maintain this equipment according to the following requirements:

Each turbine may start up as a simple cycle gas turbine. For the purposes of this condition, the beginning of a turbine startup occurs at initial fire in the combustor and the end of a turbine startup occurs when the turbine has reached 70 percent or higher load. A turbine startup shall not exceed 10 minutes.

A turbine startup is the initial step of a combined cycle startup (cold startup, warm startup, hot startup) as defined in condition C1.5.

A turbine shall operate as a combined cycle gas turbine except during turbine startup not to exceed 10 minutes.

[RULE 1304(a)-Modeling and Offset Exemption, 6-14-1996]

[Devices subject to this condition : D88, D98, D107]

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

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The operator shall comply with the terms and conditions set forth below:

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:

GHG = 61.37 * FF

Where GHG is the greenhouse gas emissions in tons of CO_2 and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per net megawatt-hours based on a 12-month rolling average. The GHG emissions from this equipment shall not exceed 572,378 tons per turbine per year on a 12-month rolling average basis. The calendar annual average GHG emissions shall not exceed 1063.3 lbs per net megawatt-hours (1148.4 lbs per net megawatt-hours inclusive of equipment degradation).

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, 12-10-2012]

[Devices subject to this condition : D88, D98, D107]

E193.7 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

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SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

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

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

GHG = 61.37 * FF

Where GHG is the greenhouse gas emissions in tons of CO_2 and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per gross megawatt-hours on a 12-month rolling average. The calendar annual average GHG emissions shall not exceed 1000 lbs per gross megawatt-hours, or the applicable limit that is published in the final EPA regulation, if RBEP meets the applicability criteria for the final EPA regulation.

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.

[40CFR 63 Subpart KKKK, 4-20-2006]

[Devices subject to this condition : D88, D98, D107]

E193.8 The operator shall construct this equipment according to the following requirements:

The Permit to Construct shall become invalid if construction is not commenced within 18 months after the issuance date, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The EPA Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified.

[40CFR 52.21 - PSD, 6-19-1978]

[Devices subject to this condition : D88, D98, D107]

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The operator shall comply with the terms and conditions set forth below:

I297.6 This equipment shall not be operated unless the facility holds 22645 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, 6-3-2011]

[Devices subject to this condition : D111]

K. Record Keeping/Reporting

K40.2 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.1, D29.2, and D29.3 are conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

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, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

FACILITY PERMIT TO OPERATE
AES REDONDO BEACH, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

[RULE 1303, 5-10-1996; RULE 1303, 12-6-2002; **RULE 1703 - PSD Analysis, 10-7-1988; RULE 2005, 6-3-2011]**

[Devices subject to this condition : D88, D98, D107]

K67.6 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use during the commissioning period

[RULE 2012, 5-6-2005]

[Devices subject to this condition : D88, D98, D107]

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 176	PAGE 1
ENGINEERING AND COMPLIANCE	APPL. NO. 545065-545072, 549120	DATE 6/11/14
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY

AES REDONDO BEACH, LLC
P.O. BOX 210307
DALLAS, TX 75211

FACILITY ID: 115536

EQUIPMENT LOCATION: 1100 N. Harbor Dr
Redondo Beach, CA 90277

Contact: Stephen O'Kane, Environmental Management and Regulatory Compliance Manager

PERMITS TO CONSTRUCT FOR REDONDO BEACH ENERGY PROJECT (RBEP)

EQUIPMENT DESCRIPTION

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

Note: *In Section H, all equipment are for the new RBEP project.*

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
PROCESS 5: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, AQUEOUS AMMONIA 19 PERCENT, 12,000 GALS; DIAMETER: 12 FT; LENGTH: 15 FT A/N: 545072	D87				C157.1, E144.1, E193.3
PROCESS 10: INTERNAL COMBUSTION - POWER GENERATION					
GAS TURBINE, NO. 03-A, COMBINED CYCLE, NATURAL GAS, MITSUBISHI POWER SYSTEMS AMERICAS, MODEL 501DA, 1492 MMBTU/HR HHV AT 33 F, WITH DRY LOW-NOX COMBUSTOR WITH A/N: 545068	D88	C93	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2**: 1063.3 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1148.4 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter	A63.1, A99.1, A99.2, A195.5, A195.6, A195.7, A327.1, B61.4, C1.5, C1.6, D29.1, D29.2, D82.1, D82.2, E193.3, E193.4, E193.5, E193.6, E193.7, E193.8, E193.9, I297.1, K40.2, K67.6
GENERATOR, CTG NO. 03-A, 131.9 MW GROSS AT 33 F	[B89]				
HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG) NO. 03-A	[B90]				

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
GENERATOR, STEAM TURBINE GENERATOR (STG), NO. 03-ST1, 150.7 MW GROSS AT 33 F, COMMON WITH HRSG NOS. 03-B AND 03-C	[B91]			11]; CO2: 1000 lbs/gross MWh [40 CFR 63 Subpart KKKK, 4-20-2006] *Note: CO_2 emissions will be added to the facility permit when the FP system programming is updated.* **NOx**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]; NOx: 8.88 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 25 PPMV NATURAL GAS (8) [40CFR60 SUBPART KKKK, 7-6-2006]; NOx: 13.08 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **PM10:** 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 4.5 LB/HR NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-	

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 SUBPART KKKK, 7-6-2006]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
DUCT BURNER, NATURAL GAS, COEN/JOHN ZINK, MODEL LDRW, OR EQUIVALENT, SERVING HRSG NO. 03-A, 507 MMBTU/HR A/N: 545068	D92	C93	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2:** 1063.3 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1148.4 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1000 lbs/gross MWh [40 CFR 63 Subpart KKKK, 4-20-2006] **NOx**: 2.0 PPMV	I297.2

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]; NOx: 8.88 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 25 PPMV NATURAL GAS (8) [40CFR60 SUBPART KKKK, 7-6-2006]; NOx: 13.08 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **PM10:** 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 5.0 LB/HR NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU	

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				NATURAL GAS (8) [40CFR 60 SUBPART KKKK, 7-6-2006]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. 03-A, JOHNSON MATTHEY, MODEL SC42, OR EQUIVALENT, CATALYST VOLUME: 203 CUBIC FEET A/N: 545066	C93	D88, D92, C94			
SELECTIVE CATALYTIC REDUCTION, NO. 03-A, HALDOR TOPSOE, MODEL DNX GT-201, OR EQUIVALENT, 2804 CU.FT., WITH A/N: 545066 AMMONIA INJECTION, AQUEOUS AMMONIA	C94 [B95]	C93, S96		NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.8, D12.8, D12.9, D12.10, 29.3, E179.3, E179.4, E193.3
STACK, TURBINE NO. 03-A, HEIGHT: 140 FT; DIAMETER: 18 FT A/N: 545068	S96	C94			
GAS TURBINE, NO. 03-B, COMBINED CYCLE, NATURAL GAS, MITSUBISHI POWER SYSTEMS AMERICAS, MODEL 501DA, 1492 MMBTU/HR HHV AT 33 F, WITH DRY LOW-NOX COMBUSTOR WITH A/N: 545069 GENERATOR, CTG NO. 03-B, 131.9 MW GROSS AT 33 F HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG) NO. 03-B	D98 [B99] [B100]	C103	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2:** 1063.3 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1148.4 lbs/netMWh [RULE 1714, 12-10-2012;	A63.1, A99.1, A99.2, A195.5, A195.6, A195.7, A327.1, B61.4, C1.5, C1.6, D29.1, D29.2, D82.1, D82.2, E193.3, E193.4, E193.5, E193.6, E193.7, E193.8, E193.9, I297.3, K40.2, K67.6

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
GENERATOR, STEAM TURBINE GENERATOR (STG), NO. 03-ST1, 150.7 MW GROSS AT 33 F, COMMON WITH HRSG NOS. 03-A AND NO. 03-C	[B101]			CCR Title 20 Chapter 11]; CO2: 1000 lbs/gross MWh [40 CFR 63 Subpart KKKK, 4-20-2006] **NOx**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]; NOx: 8.88 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 25 PPMV NATURAL GAS (8) [40CFR 60 SUBPART KKKK, 7-6-2006]; NOx: 13.08 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **PM10:** 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 4.5 LB/HR NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; PM10: 11 LBS/HR (5B) [RULE	

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				475, 10-8-1976; RULE 475, 8-7-1978]; **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 SUBPART KKKK, 7-6-2006]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
DUCT BURNER, NATURAL GAS, COEN/JOHN ZINK, MODEL LDRW, OR EQUIVALENT, SERVING HRSG NO. 03-B, 507 MMBTU/HR A/N: 545069	D102	C103		**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2**: 1063.3 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1148.4 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1000 lbs/gross MWh [40 CFR 63 Subpart KKKK, 4-20-2006] **NOx**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]; NOx: 8.88	I297.4

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 25 PPMV NATURAL GAS (8) [40CFR60 SUBPART KKKK, 7-6-2006]; NOx: 13.08 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **PM10:** 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 5.0 LB/HR NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 SUBPART KKKK, 7-6-2006]; **VOC**: 2 PPMV	

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. 03-B, JOHNSON MATTHEY, MODEL SC42, OR EQUIVALENT, CATALYST VOLUME: 203 CUBIC FEET A/N: 545067	C103	D98, D102, C104			
SELECTIVE CATALYTIC REDUCTION, NO. 03-B, HALDOR TOPSOE, MODEL DNX GT-201, OR EQUIVALENT 2804 CU.FT., WITH A/N: 545067 AMMONIA INJECTION, AQUEOUS AMMONIA	C104 [B105]	C103, S106		NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.8, D12.8, D12.9, D12.10, D29.3, E179.3, E179.4, E193.3
STACK, TURBINE NO. 03-B, HEIGHT: 140 FT; DIAMETER: 18 FT A/N: 545069	S106	C104			
GAS TURBINE, NO. 03-C, COMBINED CYCLE, NATURAL GAS, MITSUBISHI POWER SYSTEMS AMERICAS, MODEL 501DA, 1492 MMBTU/HR HHV AT 33 F, WITH DRY LOW-NOX COMBUSTOR WITH A/N: 545070 GENERATOR, CTG NO. 03-C, 131.9 MW GROSS AT 33 F HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG) NO. 03-C GENERATOR, STEAM TURBINE GENERATOR (STG), NO. 03-ST1, 150.7 MW GROSS AT 33 F, COMMON WITH HRSG NOS. 03-A AND 03-B	D107 [B108] [B109] [B110]	C112	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2:** 1063.3 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1148.4 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1000 lbs/gross MWh [40 CFR 63 Subpart KKKK, 4-20-2006]	A63.1, A99.1, A99.2, A195.5, A195.6, A195.7, A327.1, B61.4, C1.5, C1.6, D29.1, D29.2, D82.1, D82.2, E193.3, E193.4, E193.5, E193.6, E193.7, E193.8, E193.9, I297.5, K40.2, K67.6

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				NOx: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]; NOx: 8.88 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 25 PPMV NATURAL GAS (8) [40CFR 60 SUBPART KKKK, 7-6-2006]; NOx: 13.08 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **PM10:** 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 4.5 LB/HR NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **SO2**: (9) [40CFR 72 – Acid Rain Provisions,	

Preliminary Determination of Compliance

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 SUBPART KKKK, 7-6-2006]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
DUCT BURNER, NATURAL GAS, COEN/JOHN ZINK, MODEL LDRW, OR EQUIVALENT, SERVING HRSG NO. 03-C, 507 MMBTU/HR A/N: 545070	D111	C112	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2:** 1063.3 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1148.4 lbs/netMWh [RULE 1714, 12-10-2012; CCR Title 20 Chapter 11]; CO2: 1000 lbs/gross MWh [40 CFR 63 Subpart KKKK, 4-20-2006] **NOx**: 2.0 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]; NOx: 8.88 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 25 PPMV NATURAL	I297.6

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				GAS (8) [40CFR60 SUBPART KKKK, 7-6-2006]; NOx: 13.08 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **PM10:** 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 5.0 LB/HR NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 SUBPART KKKK, 7-6-2006]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
CO OXIDATION CATALYST, NO. 03-C, JOHNSON MATTHEY, MODEL SC42, OR EQUIVALENT, CATALYST VOLUME: 203 CUBIC FEET A/N: 545071	C112	D107, D111, C113			
SELECTIVE CATALYTIC REDUCTION, NO. 03-C, HALDOR TOPSOE, MODEL DNX GT-201, OR EQUIVALENT, 2804 CU.FT. WITH A/N: 545071 AMMONIA INJECTION, AQUEOUS AMMONIA	C113 [B114]	C112, S115		NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.8, D12.8, D12.9, D12.10, D29.3, E179.3, E179.4, E193.3
STACK, TURBINE NO. 03-C, HEIGHT: 140 FT; DIAMETER: 18 FT A/N: 545070	S115	C113			
PROCESS 11: OIL/WATER SEPARATION					
OIL WATER SEPARATOR, NO. OWS01, ABOVE GROUND, 3000 GALS; HEIGHT: 5 FT; WIDTH: 5 FT; LENGTH: 18 FT A/N: 549120	D116				E193.3

(1)	Denotes RECLAIM emission factor	(2)	Denotes RECLAIM emission rate
(3)	Denotes RECLAIM concentration limit	(4)	Denotes BACT emissions limit
(5)(5A)(5B)	Denotes command & control emission limit	(6)	Denotes air toxic control rule limit
(7)	Denotes NSR applicability limit	(8)(8A)(8B)	Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc)
(9)	See App B for Emission Limits	(10)	See Section J for NESHAP/MACT requirements

** Refer to Section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY CONDITIONS

Note: Conditions F9.1, F18.1, F21.1, and F24.1 are existing facility conditions, which appear in both Sections D and H. The other conditions are new.

F9.1 Except for open abrasive blasting operations, the operator shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated No. 1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

(b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

[RULE 401, 3-2-1984; RULE 401, 11-9-2001]

F18.1 *This condition sets forth the Acid Rain SO_2 Allowance Allocation for affected units, Boilers No. 5, 6, 7, 8, and 17, applicable to calendar years 2010 and beyond.*

[40CFR 73 Subpart B, 1-11-1993]

F21.1 *This condition sets forth the Acid Rain SO_2 Allowance Allocation for retired units, Boilers No. 11, 12, 13, 14, 15, 16, applicable to calendar years 2010 and beyond.*

[40CFR 73 Subpart B, 1-11-1993]

F24.1 Accidental release prevention requirements of Section 112(r)(7):

a). The operator shall comply with the accidental release prevention requirements pursuant to 40 CFR Part 68 and shall submit to the Executive Officer, as a part of an annual compliance certification, a statement that certifies compliance with all of the requirements of 40 CFR Part 68, including the registration and submission of a risk management plan (RMP).

b). The operator shall submit any additional relevant information requested by the Executive Officer or designated agency.

[RULE 40 CFR68 – Accidental Release Prevention, 5-24-1996]

Note: Facility condition F24.1 is applicable to the two existing ammonia tanks in Section D, Devices D18 and D83, because they are permitted to use 29% aqueous ammonia. This condition is not applicable to the new ammonia tank (Device D87) installed with the RBEP project because it is permitted to contain 19% ammonia, not anhydrous ammonia or ammonia with a 20% or greater concentration. Condition F24.1 will be removed from the facility permit after D18 and D83 are removed from the facility.

F52.1 The facility is subject to the applicable requirements of the following rules or regulations(s):

The facility shall submit a detailed retirement plan for the permanent shutdown of Boilers No. 6 (Device D23), No. 7 (Device D6), and No. 8 (Device D8) describing in detail the steps and schedule that will be taken to render Boilers Nos. 6, 7, and 8 permanently inoperable. The retirement plan shall be submitted to SCAQMD within 60 days after Permits to Construct for Gas Turbines No. 03-A (Device D88), 03-B (Device D98), and 03-C (Device D107) are issued.

The retirement plan must be approved in writing by SCAQMD. AES shall not commence any construction of the Redondo Beach Energy Project including Gas Turbines Nos. 03-A, 03-B, 03-C, Steam Turbine No. 03-ST1, and SCR/CO catalysts for Gas Turbine Nos. 03-A, 03-B, 03-C, before the retirement plan is approved in writing by SCAQMD. If SCAQMD notifies AES that the plan is not approvable, AES shall submit a revised plan addressing SCAQMD's concerns within 30 days.

Within 30 calendar days of actual shutdown but no later than December 31, 2018, AES shall provide SCAQMD with a notarized statement that Boilers No. 6, 7, and 8 are permanently shut down and that any re-start or operation of the boilers shall require new Permits to Construct and be subject to all requirements of nonattainment new source review and the prevention of significant deterioration program.

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers No. 6, 7, and 8, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 31, 2018.

AES shall cease operation of Boilers No. 6 (Device D23), No. 7 (Device D6), and No. 8 (D8) within 90 calendar days of the first fire of Gas Turbines No. 03-A (Device D88), No. 03-B (Device D98), or No. 03-C (Device D107).

[Rule 1304(a)—Modeling and Offset Exemption, 6-14-1996; Rule 1313(d), 12-7-1995]

F52.2 The facility is subject to the applicable requirements of the following rules or regulations(s):

For all circuit breakers at the facility utilizing SF6, including the circuit breakers serving Gas Turbines No. 03-A, 03-B, and 03-C, Steam Turbine Generator No. 03-ST1, and the electrical connection line, the operator shall install, operate, and maintain enclosed-pressure SF6 circuit breakers with a maximum annual leakage rate of 0.5 percent by weight. The circuit breakers shall be equipped with a 10 percent by weight leak detection system.

The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations shall be maintained on site.

The total CO2e emissions from all circuit breakers shall not exceed 17.8 tons per calendar year.

[Rule 1714, 12-10-2012]

DEVICE CONDITIONS

GAS TURBINES

A63.1 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
VOC	Less than or equal to 14121 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 4278 LBS IN ANY CALENDAR MONTH
SOx	Less than or equal to 1583 LBS IN ANY CALENDAR MONTH

For the purposes of this condition, the above emission limits shall be based on the emissions from a single turbine.

The turbine shall not commence with normal operation until the commissioning process has been completed. Normal operation commences when the turbine is able to supply electrical energy to the power grid as required under contract with the relevant entities. The SCAQMD shall be notified in writing once the commissioning process for each turbine is completed.

Normal operation may commence in the same calendar month as the completion of the commissioning process provided the turbine is in compliance with the above emission limits.

The operator shall calculate the monthly emissions for VOC, PM10, and SOx using the equation below.

Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)

For commissioning, the emission factors shall be as follows: VOC, 22.29 lb/mmcf; PM10, 4.63 lb/mmcf; and SOx, 1.68 lb/mmcf.

For normal operation, the emission factors shall be as follows: VOC, 6.45 lb/mmcf; PM10, 3.73 lb/mmcf; and SOx, 1.38 lb/mmcf.

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

Each turbine shall not be operated more than 6835 hours (including 470 hours with duct firing) in any calendar year, including startups and shutdowns, but not commissioning.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1304.1, 9-6-2013; RULE 1703-PSD Analysis, 10-7-1988]

[Devices subject to this condition: D88, D98, D107]

A99.1 The 13.08 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D88, D98, D107]

A99.2 The 8.88 lbs/mmscf NOx emission limit(s) shall only apply during the interim period after commissioning to report RECLAIM emissions.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D88, D98, D107]

A195.5 The 2.0 PPMV NOx emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, cold startups, warm startups, hot startups, and shutdown periods.

[RULE 1703 – PSD Analysis, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: D88, D98, D107]

A195.6 The 2.0 PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, cold startups, warm startups, hot startups, and shutdown periods.

[RULE 1703 – PSD Analysis, 10-7-1988]

[Devices subject to this condition: D88, D98, D107]

A195.7 The 2.0 PPMV VOC emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, cold startups, warm startups, hot startups, and shutdown periods.

[RULE 1303(a)(1)-BACT; 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D88, D98, D107]

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

[RULE 475, 10-8-1976; RULE 475, 8-7-1978]

[Devices subject to this condition: D88, D98, D107]

B61.4 The operator shall not use natural gas containing the following specified compounds:

Compound	Range	Grain per 100 scf
H2S	Greater than	0.25

This concentration limit is an annual average based on monthly samples 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 1304.1, 9-6-2013]

[Devices subject to this condition: D88, D98, D107]

C1.5 The operator shall limit the number of start-ups to no more than 90 in any one calendar month.

The number of cold startups shall not exceed 5 in any calendar month, the number of warm startups shall not exceed 25 in any calendar month, and the number of hot starts shall not exceed 60 in any calendar month, with no more than 3 startups in any one day.

The number of cold startups shall not exceed 24 in any calendar year, the number of warm startups shall not exceed 150 in any calendar year, and the number of hot startups shall not exceed 450 in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the steam turbine has been shut down for more than 49 hours. A cold startup shall not exceed 90 minutes. The NOx emissions from a cold startup shall not exceed 28.7 lbs. The CO emissions from a cold startup shall not exceed 115.9 lbs. The VOC emissions from a cold startup shall not exceed 27.9 lbs.

For the purposes of this condition, a warm startup is defined as a startup which occurs after the steam turbine has been shut down between 9 and 49 hours, inclusive. A warm startup shall not exceed 32.5 minutes. The NOx emissions from a warm startup shall not exceed 16.6 lbs. The CO emissions from a warm startup shall not exceed 46.0 lbs. The VOC emissions from a warm startup shall not exceed 21.0 lbs.

For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 9 hours. A hot startup shall not exceed 32.5 minutes. The NOx emissions from a hot startup shall not exceed 16.6 lbs. The CO emissions from a hot startup shall not exceed 33.6 lbs. The VOC emissions from a hot startup shall not exceed 20.4 lbs.

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

The operator shall maintain records in a manner approved by the District, to demonstrate compliance with this condition.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2012, 5-6-2005]

[Devices subject to this condition: D88, D98, D107]

C1.6 The operator shall limit the number of shutdowns to less than 90 in any one calendar month.

The number of shutdowns shall not exceed 624 in any calendar year.

Each shutdown shall not exceed 10 minutes. The NOx emissions from a shutdown event shall not exceed 9.0 lbs. The CO emissions from a shutdown event shall not exceed 45.3 lbs. The VOC emissions from a shutdown event shall not exceed 31.0 lbs.

The operator shall maintain records in a manner approved by the District, to demonstrate compliance with this condition.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2012, 5-6-2005]

[Devices subject to this condition: D88, D98, D107]

D29.1 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOx emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	Approved District Method	District-approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	Approved District Method	District-approved averaging time	Outlet of the SCR serving this equipment
PM 2.5	EPA Method 201A and 202	4 hours	Outlet of the SCR serving this equipment
NH3 emissions	District Method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

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

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

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

For gas turbines only the VOC test shall use the following method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to having less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the canisters temperature when extracting samples for analysis is not to be below 70 deg F.

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results must be reported with two significant digits.

The sampling time for the PM2.5 tests shall be 4 hours or longer as necessary to obtain a measureable amount of sample.

The test shall be conducted when this equipment is operating at loads of 70 and 100 percent of maximum load without duct burner firing, and 100 percent of maximum load with duct burner firing.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: D88, D98, D107]

D29.2 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
SOx emissions	Approved District Method	District-approved averaging time	Fuel Sample

VOC emissions	Approved District method	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	Approved District Method	District-approved averaging time	Outlet of the SCR serving this equipment

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

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 when this equipment is operating at 100 percent of maximum load without duct burner firing, and 100 percent of maximum load with duct burner firing.

For gas turbines only the VOC test shall use the following method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to having less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the canisters temperature when extracting samples for analysis is not to be below 70 deg F.

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results must be reported with two significant digits.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002, RULE 1703(a)(2)-PSD-BACT, 10-7-1988]

[Devices subject to this condition: D88, D98, D107]

D82.1 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 to measure CO concentrations over a 15 minute averaging time period.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

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

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9% - %O_2 d)][(Qg * HHV)/10E+06], where:

1. K = 7.267 *10E-08 (lb/scf)/ppm
2. Cco = Average of four consecutive 15 min. average CO concentrations, ppm
3. Fd = 8710 dscf/MMBTU natural gas
4. %O_2 d = Hourly average % by volume O_2 dry, corresponding to Cco
5. Qg = Fuel gas usage during the hour, scf/hr
6. HHV = Gross high heating value of fuel gas, BTU/scf

[RULE 1703 – PSD Analysis, 10-7-1988]

[Devices subject to this condition: D88, D98, D107]

D82.2 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

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

[RULE 1703 – PSD Analysis, 10-7-1988; RULE 2005, 6-3-2011; RULE 2012, 5-6-2005]

[Devices subject to this condition: D88, D98, D107]

E193.3 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-03 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D87, D88, C94, D98, C104, D107, C113, D116]

E193.4 The operator shall operate and maintain this equipment according to the following requirements:

The commissioning period shall not exceed 491 hours of operation for each turbine from the date of initial turbine start-up. Three turbines may be commissioned at the same time.

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

The operator shall provide the SCAQMD with written notification of the initial startup date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from SCAQMD.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: D88, D98, D107]

E193.5 The operator shall operate and maintain this equipment according to the following requirements:

Each turbine may start up as a simple cycle gas turbine. For the purposes of this condition, the beginning of a turbine startup occurs at initial fire in the combustor and the end of a turbine startup occurs when the turbine has reached 70 percent or higher load. A turbine startup shall not exceed 10 minutes.

A turbine startup is the initial step of a combined cycle startup (cold startup, warm startup, hot startup) as defined in condition C1.5.

A turbine shall operate as a combined cycle gas turbine except during turbine startup not to exceed 10 minutes.

[Rule 1304(a)—Modeling and Offset, 6-14-1996]

[Devices subject to this condition: D88, D98, D107]

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

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:

GHG = 61.37 * FF

Where GHG is the greenhouse gas emissions in tons of $CO2$ and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per net megawatt-hours based on a 12-month rolling average. The GHG emissions from this equipment shall not exceed 572,378 tons per turbine per year on a 12-month rolling average basis. The calendar annual average GHG emissions shall not exceed 1063.3 lbs per net megawatt-hours (1148.4 lbs per net megawatt-hours inclusive of equipment degradation).

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, 12-10-2012; CCR Title 20 Chapter 11—*This rule tag will be added to the facility permit when the FP system programming is updated.*]

[Devices subject to this condition: D88, D98, D107]

E193.7 The operator shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

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

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

GHG = 61.37 * FF

Where GHG is the greenhouse gas emissions in tons of CO_2 and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per gross megawatt-hours on a 12-month rolling average. The calendar annual average GHG emissions shall not exceed 1000 lbs per gross megawatt-hours, or the applicable limit that is published in the final EPA regulation, if RBEP meets the applicability criteria for the final EPA regulation.

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.

[40 CFR 63 Subpart KKKK, 4-20-2006]

[Devices subject to this condition: D88, D98, D107]

E193.8 The operator shall construct this equipment according to the following requirements:

The Permit to Construct shall become invalid if construction is not commenced within 18 months after the issuance date, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The EPA Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified.

[Devices subject to this condition: D88, D98, D107]

[40 CFR 52.21 – PSD, 6-19-1978]

E193.9 The operator shall construct this equipment according to the following requirements:

The Permit to Construct shall become invalid if construction is not commenced within 24 months after the issuance date, if construction is discontinued for a period of 24 months or more, or if construction is not completed within a reasonable time. The Executive Officer may extend the 24-month period upon a satisfactory showing that an extension is justified.

[Devices subject to this condition: D88, D98, D107]

[Rule 1713, 10-7-1988—*This rule tag will be added to the facility permit when the FP system programming is updated.*]

I297.1 This equipment shall not be operated unless the facility holds 66641 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, 6-3-2011]

[Devices subject to this condition: D88]

I297.2 This equipment shall not be operated unless the facility holds 22645 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, 6-3-2011]

[Devices subject to this condition: D92]

I297.3 This equipment shall not be operated unless the facility holds 66641 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, 6-3-2011]

[Devices subject to this condition: D98]

I297.4 This equipment shall not be operated unless the facility holds 22645 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, 6-3-2011]

[Devices subject to this condition: D102]

I297.5 This equipment shall not be operated unless the facility holds 66641 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, 6-3-2011]

[Devices subject to this condition: D107]

I297.6 This equipment shall not be operated unless the facility holds 22645 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, 6-3-2011]

[Devices subject to this condition: D111]

K40.2 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.1, D29.2, and D29.3 are conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

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, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[Rule 1303, 5-10-1996; RULE 1303, 12-6-2002; RULE 1703-PSD Analysis, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: D88, D98, D107]

K67.6 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use during the commissioning period

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D88, D98, D107]

SCR/CO CATALYSTS

A195.8 The 5.0 PPMV NH3 emission limit is averaged over 1 hour, dry basis at 15 percent oxygen.

The operator shall calculate and continuously record the NH3 slip concentration using the following equation:

NH_3 (ppmvd) = [a-b*(c*1.2)/1,000,000]*1,000,000/b, where:

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

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to within plus or minus 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedure shall be in effect no later than 90 days after initial startup of the turbine.

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

[Rule 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: C94, C104, C113]

D12.8 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH_3).

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The operator shall maintain the ammonia injection rate between 11.8 and 33 gallons per hour.

[Rule 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: C94, C104, C113]

D12.9 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 400 degrees F and 700 degrees F, except during startups and shutdowns.

[Rule 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: C94, C104, C113]

D12.10 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure differential shall be between 1.5 and 3.5 inches water column.

[Rule 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: C94, C104, C113]

D29.3 The operator shall conduct source test(s) for the pollutant(s) identified below.

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

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

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

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

[Rule 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: C94, C104, C113]

E179.3 For the purpose of the following condition number(s) continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D 12-8

Condition Number D 12-9

[Rule 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2) – PSD BACT, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: C94, C104, C113]

E179.4 For the purpose of the following condition number(s) continuously record shall be defined as recording at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number D 12-10

[Rule 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2) – PSD BACT, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: C94, C104, C113]

E193.3 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-03 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D87, D88, C94, D98, C104, D107, C113, D116]

AMMONIA TANK

****Note: Conditions C157.1 and E144.1 are from Section D for the two existing aqueous ammonia tanks. Condition E193.3 is new.*

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

[~~RULE 402, 5-7-1976~~, **<u>RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002</u>**]

[Devices subject to this condition: D87]

E144.1 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.

[RULE 1303(a)(1)-BACT, 5-10-1996; **<u>RULE 1303(a)(1)-BACT, 12-6-2002</u>**]

[Devices subject to this condition: D87]

E193.3 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-03 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D87, D88, C94, D98, C104, D107, C113, D116]

OIL WATER SEPARATOR

E193.3 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-03 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D87, D88, C94, D98, C104, D107, C113, D116]

BACKGROUND AND FACILITY DESCRIPTION

Existing Facility

A power plant was first built on the site in 1906–1907, and was operated for several years by the Pacific Light and Power Company. In 1917, the company and the power plant were purchased by Southern California Edison (SCE) who later built Utility Boilers No. 1 - 4, which came on line in 1948 and 1949. Utility Boilers No. 5 and 6 were added later, coming on line in 1956, and Utility Boilers No. 7 and 8 came on line in 1968. The AES Corporation purchased the power plants from SCE in 1998.

AES Redondo Beach, LLC (AES) (ID 115536), a wholly owned subsidiary of AES Southland, LLC (AES), operates the existing Redondo Beach Generating Station (RBGS), which currently has four operating utility boilers (Units 5, 6, 7, and 8), four retired utility boilers (Units 1, 2, 3, and 4), a steam boiler (No. 17), two aqueous ammonia tanks (29 wt %), and Rule 219 exempt equipment.

A summary of the operating utility boilers are summarized in the table below.

Table 1 – Existing Utility Boilers

Application No. (Permit No.)	Equipment Description (Device No.)	Rating
408714 (F99317)	Boiler, No. 5, Babcock and Wilcox, natural gas/refinery gas (D20)	1785 MMBtu/hr, 175 MW
408716 (F99321)	Boiler, No. 6, Babcock and Wilcox, natural gas/refinery gas (D23)	1785 MMBtu/hr, 175 MW
408717 (F57270)	Boiler, No. 7, Babcock and Wilcox, natural gas/refinery gas (D6)	4752.2 MMBtu/hr, 480 MW
408719 (F57271)	Boiler, No. 8, Babcock and Wilcox, natural gas/refinery gas (D8)	4752.2 MMBtu/hr, 480 MW
	Total Generating Capacity	**13,074.4 MMBtu/hr, 1310 MW**

Retired Units 1 – 4 are no longer on the facility permit. Boiler No. 17 (D72) produces steam only and has been converted to a RECLAIM non-operated major source.

The facility is a federal Title V and Acid Rain facility, as well as a RECLAIM facility (Cycle 1). The facility is currently in compliance with all federal, state, and local rules and regulations.

Proposed Facility

- *Project Description*

  AES proposes to construct, own, and operate a new electrical generating plant. The Redondo Beach Energy Project (RBEP) is a natural-gas-fired, combined-cycle, air-cooled electrical generating facility with a gross generating capacity of 546.4 megawatts (MW) and net generating capacity of 530.4 MW, which will replace the existing RBGS and be constructed entirely within the 50-acre site. The development of RBEP includes the demolition and removal of the RBGS.

The RBEP facility will occupy approximately 10.5 acres of the existing 50-acre site. The SCE high-voltage switchyard located on RBEP property occupies approximately 2.2 acres of additional land, making the total industrial footprint approximately 12.7 acres.

The RBEP site is located near sea level on the California coast and is bounded to the north by residential areas, to the east by a storage facility and office buildings, to the south by mixed use residential and commercial areas, and to the west by King Harbor marina and the Pacific Ocean. The site is located on a gently sloping coastal plain. Specifically, the site is located southeast of the intersection of North Harbor Drive and Herondo Street in Redondo Beach.

RBEP will consist of one 3-on-1 combined-cycle gas turbine power block with three natural-gas-fired combustion turbine generators (CTGs), three heat recovery steam generators (HRSGs) with natural gas duct burners, one steam turbine generator (STG), air-cooled condenser, and related ancillary equipment. Each combustion turbine generator is rated 131.9 MW gross and 128 MW net. The steam generator is rated 150.7 MW gross and 146.4 MW net. These maximum ratings occur at an ambient temperature of 33 °F. Three selective catalytic reduction (SCR) systems and CO oxidation catalysts will be utilized for control of NOx and CO/VOC emissions, respectively. One 12,000-gallon ammonia (NH_3) storage tank will store 19% aqueous ammonia which is the reducing agent in the SCRs. An oil water separator will be used to collect equipment wash water and rainfall.

The repowering will bring the RBGS into compliance with the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy) by the current compliance date of December 31, 2020. On May 4, 2010 the State Water Board adopted the Policy, which became effective on October 1, 2010. The Policy applies to existing power plants that currently have the ability to withdraw cooling water from the State's coastal and estuarine waters using a single-pass system, also known as once-through cooling (OTC). The new generating units will employ an air-cooled condenser and will eliminate the use of ocean water for once-through cooling at the site.

The RBEP will connect to the existing onsite high-voltage electric transmission, water pipelines, natural gas pipeline systems, sanitary sewer and wastewater discharge systems, and other infrastructure as needed, thereby avoiding the need to construct any new offsite facilities. A new 230-kv transmission interconnection will connect the RBEP block to the existing on-site SCE 230-kv switchyard.

The facility will continue as a federal Title V and Acid Rain facility, as well as a RECLAIM facility (Cycle 1).

Modeling and Offset Exemption
SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects. The exemption applies to: "The source is replacement of electric utility steam boiler(s)

with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basinwide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset."

The initial purpose of this exemption was to facilitate the replacement of older, less efficient utility boilers and steam turbines with newer lower NOx-emitting gas turbines for electric power generating systems to comply with Rule 1135—Emissions of Oxides of Nitrogen from Electric Power Generating Systems. As the RECLAIM program subsequently superseded Rule 1135, the exemption was expanded to included modifications to comply with RECLAIM requirements.

AES proposes to replace existing Utility Boiler No. 6 (175 MW), No. 7 (480 MW) and No. 8 (480 MW) with RBEP, which consists of a 3-on-1 combined-cycle gas turbine power block, rated at 546.4 MW gross. To offset the 546.4 MW for the RBEP, 480 MW is coming from the shutdown of Boiler No. 7 (480 MW) and 66.4 MW is coming from the shutdown of Boilers Nos. 6 and 8 (655 MW combined). The surplus 588.6 MW from the shutdown of Boilers Nos. 6 and 8 will be used to offset the repowering projects at AES Huntington Beach and AES Alamitos. Utility Boiler No. 5 will be shut down, but AES has not specified a use for the offsets resulting from the shutdown of this unit.

The general Rule 1304(a)(2) offset plan proposed by AES for the three repowering projects with offsets coming from the shutdowns of utility boilers (retirement of units) at the three existing power plants is summarized in the table below. At AES Huntington Beach, the existing plant is the Huntington Beach Generating Station (HBGS) and the repowering project is the Huntington Beach Energy Project (HBEP). At AES Alamitos, the existing plant is the Alamitos Generating Station (AGS) and the repowering project is the Alamitos Energy Center (AEC).

Table 1A – AES Rule 1304(a)(2) Offset Plan

Project	Phase	First Fire or Shutdown Date	MW (gross)[a]	MW (net)[b]
HBEP	Block 1	9/1/2018	545.5	527.8
	RBGS Unit 6 retired	9/1/2018	175	175
	RBGS Unit 8 retired	9/1/2018	480	480
	Block 2	3/1/2020	545.5	411.2
	HBGS Unit 1 retired	5/29/2020	215	215
	HBGS Unit 2 retired	5/29/2020	215	215
	MW Installed[c]		972	939
	MW Retired		1,085	1,085

Project	Phase	First Fire or Shutdown Date	MW (gross)[(a)]	MW (net)[(b)]
	Surplus MW		113	146
RBEP	Block 1	9/2019	546.3	530.4
	RBGS Unit 5 retired	1/31/2019	175	175
	RBGS Unit 7 retired	1/31/2019	480	480
	MW Installed		546.3	530.4
	MW Retired		655	655
	Surplus MW (HBEP & RBEP)		221.7	270.6
AEC	Blocks 1&2	2/1/2019	1,077.9	1,047
	AGS Unit 5 retired	10/1/2018	480	480
	AGS Unit 6 retired	10/1/2018	480	480
	Block 3	5/1/2022	538.95	523.5
	AGS Unit 3 retired	1/1/2022	320	320
	AGS Unit 4 retired	1/1/2022	320	320
	Block 4	8/1/2025	538.95	523.5
	AGS Unit 1 retired	8/1/2025	175	175
	AGS Unit 2 retired	8/1/2025	175	175
	MW Installed		**2,156**	**2,094**
	MW retired (including HBEP & RBEP Surpluses)		**2,171.7**	**2,220.6**

(a), (b) The MWs are based on ambient temperatures of 32°F (HBEP), 33°F (RBEP), and 28°F (AEC).

(c) The total MW installed would be 1091 MW(gross) for blocks 1 & 2; however, the HBEP site has a transmission constraint of 939 MW(net) and a permit condition of 972 MW(gross).

Proposed Schedule

Construction and demolition activities at the project site are anticipated to last 60 months, from January 2016 until December 2020. The first activities to occur onsite will be the dismantling and partial removal of existing Units 1- 4. The major generating equipment including steam turbines, generators, boilers, and duct work will be removed, leaving the administration building and western portion of the building that houses Units 1- 4 intact. These buildings will be left standing temporarily to provide screening between the construction site of the new power block and Harbor Drive. Construction of the new power block will begin in the first quarter of 2017 and continue through to the end of the second quarter 2019, when it will be ready for commercial operation. Although the new power block will be operational, construction will continue through 2019 including construction of the new control building. The existing Units 5 - 8 and auxiliary boiler no. 17 will remain in service until the second quarter of 2018. Units 5 - 8 and auxiliary boiler no.

17 will be demolished starting the first quarter of 2019 through the fourth quarter of 2020. Finally, the remaining buildings and structures left standing will be demolished and removed by the end of 2020.

Major project milestones are listed in the following table.

Table 2 - RBEP Schedule Major Milestones

Activity	Date
Begin dismantling and removal of retired Units 1 – 4	First quarter 2016
Removal of equipment from retired Units 1 - 4 complete	Fourth quarter 2016
Begin construction of new power block	First quarter 2017
Retire existing Units 5 - 8 and auxiliary boiler no. 17	Second quarter 2018
Begin demolition of existing Units 5 - 8 and auxiliary boiler no. 17	First quarter 2019
Startup and test new power block	First and second quarter 2019
Complete construction/start commercial operations	Third quarter 2019
Complete demolition	Fourth quarter 2020

California Energy Commission

The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger, including any related facilities such as transmission lines, fuel supply lines, and water pipelines. The CEC's 12-month permitting process is a certified regulatory program under the California Environmental Quality Act (CEQA) and includes various opportunities for public and inter-agency participation. The CEC's certification process subsumes all requirements of local, regional, state, and federal agencies required for the construction of a new plant. The CEC coordinates its review of the proposed facility with the agencies that will be issuing permits to ensure that its certification incorporates the conditions that are required by these various agencies. As the RBEP will be rated at greater than 50 megawatts, it is subject to the CEC's 12-month certification process. As part of this process, AES submitted an application for certification ("AFC") (12-AFC-03) to the CEC on November 20, 2012 seeking certification for RBEP.

SCAQMD Applications Submitted

In addition to the CEC certification process, AES submitted the following applications to the District seeking Permits to Construct for the RBEP project. The environmental consultant is CH_2M Hill.

Table 3 - Applications for Permits to Construct Submitted to AQMD

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
545065	11/27/12	7/9/13	Title V/RECLAIM Significant Revision	$1789.12
545066	11/27/12	7/9/13	SCR/CO Catalyst No. 03-A	$3440.06

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
545067	11/27/12	7/9/13	SCR/CO Catalyst No. 03-B	$1720.02 (50%--identical)
545068	11/27/12	7/9/13	Mitsubishi Gas Turbine No. 03-A	$16,191.24
545069	11/27/12	7/9/13	Mitsubishi Gas Turbine No. 03-B	$8095.62 (50%--identical)
545070	11/27/12	7/9/13	Mitsubishi Gas Turbine No. 03-C	$8095.62 (50%--identical)
545071	11/27/12	7/9/13	SCR/CO Catalyst No. 03-C	$1720.02 (50%--identical)
545072	11/27/12	7/9/13	Aqueous Ammonia Storage Tank	$1364.63
549120	3/28/13	7/9/13	Oil/Water Separator	$3440.06
			Total Fee Submitted	$45,856.41

The oil/water wastewater separator is not exempt under Rule 219(p)(16), because this exemption does not include treatment processes where VOC and/or toxic materials are emitted.

Note: A/N 545066 is the master file.

<u>Applications Deem Completion Chronology</u>

The applications were submitted on 11/27/12. The SCAQMD issued four additional information ("AI") letters before the application package was deemed complete on 7/9/13. The following table sets forth a summary of the completion process.

Table 4 – Deemed Completion Chronology

Date of Letter	Letters and Issues
12/21/12	AI Letter No. 1 requested: (1) guarantee for $PM_{10}/PM_{2.5}$ emissions rates; (2) SCR and CO catalyst manufacturers and model nos., guarantees for emissions rates for NOx, CO, VOC, ammonia, and catalyst life; (3) effect of trip on start-up emissions; (4) technical discussion of "fast start technology"; (5) plans for 175 MW from retirement of unit 5; (6) revised health risk assessment using AP-42 emission factors, including for formaldehyde, instead of the CATEF emission factors used in AFC; (7) supporting calculations for the 1,082 lbs CO_2/MWh gross energy output for GHG BACT; (8) basis for maximum emissions for dispersion modeling.
1/11/13	Response Letter No. 1, dated 1/11/13, received from AES.
2/8/13	AI Letter No. 2 requested: (1) effect of trip on start-up emissions because trip will be included as part of the start-up; (2) discussion on "fast start technology" to include step-by-step process description for cold start-up, and discussion of key design changes from a conventional combined cycle system; (3) revised health risk assessment using AP-42 emission factors, including for formaldehyde; (4) revised dispersion modeling to address deficiencies identified by SCAQMD

Date of Letter	Letters and Issues
	Planning staff for the dispersion modeling performed for Huntington Beach Energy Project; (5) clarification of thermal efficiency calculations previously provided based on expected operating profile, additional calculations to be provided for permitted profile, and thermal efficiency values to be provided for MWh_{net} not MWh_{gross}; (6) identification of other turbine models or other potential facility configurations that may result in higher thermal efficiencies and lower GHG emissions, explanation as how the proposed turbine has been modified to use the "fast start technology," and discussion regarding how the determination was made that the proposed turbine is more thermally efficient than the newer turbines available today; (7) detailed analysis to support the conclusion that carbon capture and storage is infeasible for GHG BACT; (8) application for oil/water separator unless exempt under Rule 219(p)(16).
3/15/13	Response Letter No. 2, dated 3/15/13, received from AES.
4/12/13	AI Letter No. 3 requested: (1) addendum to air dispersion modeling protocol to address cumulative NO_2 impact, and upon approval of protocol, the modeling analysis; remodel NO_2 impacts with ambient ratio of 0.9 instead of 0.8 used for AFC; revise dispersion modeling for fugitive dust to be based on ground level source per Tom Chico's comments on the modeling protocol set forth in e-mail dated 7/19/12, instead of the 1-meter release height used for AFC; (2) quantitative visibility analysis for Class II areas; (3) conversion of thermal efficiency from lbs CO_2/MWh_{gross} to lbs CO_2/MWh_{net}, and proposal to meet 1100 lb CO_2/MWh_{net} GHG standard; (4) completion of Form 400-E-18 and emissions calculations for oil/water separator.
5/10/13	Response Letter No. 3, dated 5/9/13, received from AES.
6/7/13	AI Letter No. 4 requested visibility analysis for Class II areas and a cumulative impact analysis for the Federal NO_2 standard.
6/25/13	Response Letter, dated 6/26/13, received from AES.
7/9/13	Application package deemed complete by SCAQMD.

PROCESS DESCRIPTION

1. A/N 545068, 545069, 545070—Combustion Turbine Generators Nos. 03-A, 03-B, 03-C

The 3-on-1 combined-cycle gas turbine power block will consist of the following equipment:

- Three Mitsubishi Power Systems America (MPSA) Model 501DA combustion turbine generators. Each CTG is rated 131.9 MW gross and 128 MW net at 33 °F ambient temperature. The CTGs will be equipped with evaporative coolers on the inlet air system and dry low-NOx combustors. The use of the evaporative coolers is not intended as power augmentation but will be employed to mitigate CTG degradation (ambient and mechanical) to maintain the facility at or near the nominal generating capacity. The dry low-NOx combustors become functional when turbine loads reach approximately 68 percent, reducing the NOx concentrations to 9 ppm. Vogt Power International indicates the NOx is 9 ppmvd and CO is 10 ppmvd, without duct firing, both corrected to 15% O_2, at the turbine outlet.

- One single-cylinder, single-flow, impulse, axial exhaust condensing steam turbine generator rated at 150.7 MW gross and 146.4 MW net.

- Three heat recovery steam generators of the horizontal gas flow, single-pressure, natural-circulation type. Each HRSG has a natural-gas fired duct burner, Coen/John Zink, Model LDRW (or equivalent), rated at 507 MMBtu/hr, for supplemental firing in the HRSG inlet ductwork and an emission reduction system consisting of a CO catalyst and SCR in the outlet ductwork.

- One air-cooled condenser and one closed-loop cooling fin fan cooler.

CTG combustion air will flow through the inlet air filters, evaporative inlet air coolers, and associated air inlet ductwork before being compressed in the CTG compressor section and then entering the CTG combustion sections. Natural gas will be mixed with the compressed air prior to being introduced to the combustion sections and ignited. The hot combustion gases will expand through the power turbine section of the CTGs, causing them to rotate and drive the electric generators and CTG compressors. The hot combustion gases will exit the turbine sections and enter the HRSGs. The HRSGs will heat water (feed water), converting it to superheated high-pressure steam. High-pressure steam will be delivered to the high-pressure inlet section of the steam turbine. The high pressure steam is expanded as it passes through the STG and exits as low-pressure steam. The low-pressure steam enters the air-cooled condenser, which removes heat from the low-pressure steam (causing the steam to condense to water) and releases the heat to the ambient air. The condensed water, or condensate, will be returned to the HRSG feed water system for reuse.

The technology for RBEP will be configured and deployed as a multi-stage generating (MSG) asset designed to generate power across a wide range of capacity and maximum operating flexibility. The project will include multiple generators, often termed "embedded generating units," whereby combinations of embedded generating units comprise the full operational capability for each power block, from minimum to maximum generating capacity. The RBEP is designed to provide nearly continuous electrical generation from the minimum plant output of one turbine (approximately 128 MW reflecting no steam turbine output immediately following a startup) to its rated capacity of 530 MW (all three turbines at full load with no duct burners) while maintaining a relatively consistent heat rate. Because each individual CTG can only be operated through a 70 to 100 percent load range, the minimum and maximum output of each MSG state does not fully overlap, which results in a nominal dead band of generating capacity across the operating range of the power block (i.e., the power output of the 1-on-1 state at 100 percent load is lower than the 2-on-1 state at 70 percent load). Supplemental firing through the use of duct burners will be employed to minimize the dead band between states. One 507 MMBtu/hr higher heating value (HHV) natural-gas fired duct burner will be installed in the inlet ductwork of each HRSG and will be used to increase the flue gas temperature entering the HRSG from 1100 °F to a maximum of 1500 °F. This increase in exhaust gas temperature will increase the high-pressure steam flow to the STG to provide additional generating capacity, effectively increasing output until another gas turbine can come on line, thus minimizing the dead band.

The HRSGs are designed to function with the maximum heat input of three combustion turbines (CTs) operating at 100% percent load, with no duct burners operating, in new and clean condition. As the turbines age, an unrecoverable loss of efficiency of up to 5 percent will occur over time. This loss of efficiency and subsequent loss of heat input into the steam cycle can be recovered with supplemental firing. Limited supplemental firing could be employed when three CTGs are operating at 100 percent output to make up for the lost generating capacity. Due to the steam cycle size, supplemental firing of the HRSGs at the full rated capacity of the duct burners could only be deployed when there are no more than two CTGs operating. The steam cycle design will not allow for more than 105 MMBtu/hr of combined duct burner firing while all three CTGs are operating.

Table 5 - Combustion Turbine Generation Specifications

Parameters	Specifications
Manufacturer	Mitsubishi Power Systems Americas
Model	Model 501DA
Fuel Type	Public Utility Commission (PUC) Quality Natural Gas
Natural Gas Heating Value	1,050 BTU/scf

Table 6 - Combustion Turbine Generator Rating

	ISO 59 F-60% RH (Evaporative Cooling Off)	106 F-9.6% RH (Evaporative Cooling On, Case 12)	33 F – 93.8% RH (Evaporative Cooling Off, Case 2)	63.3 F – 75.2% RH (Evaporative Cooling On, Case 7)
Gas Turbine Heat Input, mmbtu/hr HHV[1]	1,388	1,353	1,492	1,398
Total Heat Input, mmbtu/hr HHV (w/duct fire)[2]	1,895	1,860	1,999	1,905
Gas Turbine Gross Output, kW[3]	121,435	115,496	131,896	121,445
Steam Turbine Gross Output, kW[3]	51,865	45,335	50,386 (150.7 MWgross rating provided by AES)	50,919
Total Gross Power Output, kW[3]	173,300	160,830	182,282	172,364
Net Power Output, Kw[3]	167,583	155,831	176,987	167,242
Net Plant Heat Rate, btu/kWh, LHV	7,354	7,706	7,481	7,417
Net Plant Heat Rate, btu/kWh, HHV	8,285	8,681	8,428	8,356

1 Cases for 106 °F, 33 °F and 63 °F heat input taken directly from M501DA Gas Turbine Expected Performance and Emissions Provided by MPSA and included in the AFC, Table 5.1B.2-MPSA 501DA Performance Data in Appendix 5.1B—Operational and Commissioning Emission Calculations. (Table 5.1B.2 is summarized in Table 12, below.) Other Case Heat inputs are taken from GT PRO model.

2 Total Heat Input per gas turbine with duct firing can only be achieved while operating in a 1-on-1 or 2-on-1 mode. The steam cycle is sized such that the maximum heat input into the steam cycle is reached in a 3-on-1 mode without duct firing.

3 All output is provided on a per turbine basis assuming a 3-on-1 operating mode. To calculate total output for the entire power block these values must be multiplied by 3.

AES is developing RBEP to provide local capacity and to assist in the integration of renewable energy in support of California's Renewable Portfolio Standard (RPS) objectives. The RBEP's design accomplishes the project objectives by being able to start up quickly, increase/decrease project electrical output quickly, efficiently generate electricity over a large range of output (128 to 530 megawatts), and capable of numerous start up and shutdowns. The project will have the ability to change its power output quickly, as much as 30 percent of its capacity per minute, which will allow it to rapidly respond and balance the fluctuations in generation and demand in the western Los Angeles Basin. The existing RBGS support grid reliability and stability. In order to do so, RBGS requires a significant start up period (over 18 hours and up to 36 hours) and as a result, is required to operate overnight at minimum loads in order to be available for operation the following day, which precludes the use of renewable energy when available. The RBEP avoids this situation by being capable of starting the combustion turbines and achieving approximately 70 percent of the rated electrical output (approximately 360 megawatts) within 10 minutes (combustion turbine only) of initiating a start up. Furthermore, with multiple combustion turbines, RBEP supports electrical grid reliability by being able to operate fewer, smaller units over a wider electrical output rate at a higher thermal efficiency than larger combined-cycle or simple-cycle peaking projects.

The strategy of the design that facilitates meeting RBEP's project objective includes selection of combustion turbines with specific characteristics, heat recovery steam generator (HRSG) design/material composition, and steam turbine design. AES is not proposing to modify the turbine to achieve fast starts. The fast start capability of the gas turbine alone is inherent in almost all gas turbine designs. Almost all gas turbines (industrial and aero-derivative) are capable of achieving nominal output in 10 minutes when operated in a simple cycle configuration. The inclusion of the steam generation system (HRSG, STG, and condenser) requires an extended startup period to allow for the gradual heating of the HRSG and steam turbine components. See discussion on hot, warm, and cold starts of the combined cycle system startup under the <u>*Emissions Calculations, Criteria Pollutants, Four Operational Modes*</u> section, below.

As it is the back-end steam cycle that limits the start and ramp speed, AES has focused on the exhaust energy conditions of the candidate turbines to determine those that do not exceed the operating limits of materials suited to the rapid cycling of a heat recovery system. By focusing on a simpler steam cycle and steam turbine (single pressure – single admission), different and more malleable materials could be employed. The end result is the "un-coupling" of the steam cycle components. No one design feature enables RBEP to achieve fast starts.

The combustion turbine start up is initiated by mechanically turning the compressor/turbine rotor to a starting speed. Once rotor starting speed is achieved, fuel combustion is initiated and after a short stabilization period the rotor speed is accelerated to rated speed (3600 revolutions per minute). This is referred to as a full speed – no load (FSNL) condition. After FSNL is achieved, the CTG is synchronized to the phase of electrical grid and the turbine load is increased. At approximately 70 percent turbine load, the dry low NOx combustors revert from the starting mode to the pre-mix mode where they are capable of achieving a 9 ppm NOx and 10 ppm CO emissions. The heat recovery steam generators are specifically designed with materials and operating conditions that do not constrain the fast start and ramp of the combustion turbine, yet provide sufficient steam production for enhanced overall efficiency. A steam bypass system provides an easy matching of the steam conditions to the steam turbine requirements and a de-coupling of the HRSG from the steam turbine, further enabling the short and simplified start-up and operation of the unit. After the combustion turbine is started, the HRSGs start producing steam. When the steam is of sufficient quantity and quality, steam is gradually introduced to the steam turbine. Each HRSG is fitted with a non-return valve and steam sparge line that provides a small amount of steam to the off-service HRSG(s) within the power block. This minimizes the amount of time needed to warm the other HRSG(s) within the power block, allowing the selective catalytic reduction and carbon monoxide catalysts to reach nominal operating temperature quickly. It is expected that during staged operation (meaning at least one combustion turbine is operating) that these components will be maintained at nominal temperature reducing the time required for a start up and minimizing start up emissions. Shutdown of the power island is fully automatic. Once a shutdown is initiated, the operating combustion turbine is unloaded; the generator breakers open automatically and the combustion turbine initiates a cool-down and coast down cycle. Simultaneously as the combustion turbine load is reduced, HRSG steam production is reduced and eventually the steam pressure is reduced. To achieve the fast start times, a steam turbine shutdown is desired from the highest possible pressure to ensure the HRSG remains hot or warm. After the combustion turbine and steam turbine are electrically disconnected from the grid, the turbine control systems will automatically engage a turning gear after the turbine rotors have coasted to a stop and the power block will be ready to re-start.

To qualify for the Rule 1304(a)(2) exemption from modeling and offsets, the RBEP equipment is required to operate as combined cycle gas turbines. Condition E193.5 requires the turbines to operate as combined cycle turbines, except the turbines may operate as simple cycle turbines during a fast start not to exceed 10 minutes.

2. <u>A/N 545066, 545067, 545071—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 03-A, 03-B, 03-C</u>
Each HRSG will be equipped with an oxidation catalyst and a selective catalytic reduction system located in the HRSG evaporator region.

- *CO Oxidation Catalyst*
  The CO oxidation catalyst, located between the HRSG and the SCR, will be used to control CO and VOC emissions. The catalyst will reduce CO emissions from 13.48 ppm (maximum with duct burner) and 10 ppm (without duct burner) to 2 ppmv, all 1-hr averages, dry basis at 15% O_2. The catalyst will reduce the VOC from 2.78 ppm (with duct burner) to 2 ppmv, all 1-hour averages, dry basis at 15% O_2. The VOC is already 2 ppm (without duct burner) at the catalyst inlet.

  The following table lists the technical specifications for the CO oxidation catalyst.

Table 7 - CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	Johnson Matthey (or equivalent)
Model	SC42 (or equivalent)
Catalyst Type	Palladium (ceramic honeycomb)
Catalyst Guaranteed Life	Vogt Power International—24,000 hrs of operation or three years after initial exhaust flow into the catalyst, whichever occurs first.
Space Velocity	552465 hr-1
Catalyst Volume	203.43 ft^3
CO removal efficiency	80% or greater
CO at stack outlet	2.0 ppmvd at 15% O_2
VOC at stack outlet	2.0 ppmvd at 15% O_2
Minimum Operating Temperature	400 °F

- *Selective Catalytic Reduction*
  The SCR catalyst will use ammonia injection in the presence of the catalyst to further reduce the NOx concentration in the exhaust gases. Diluted 19% aqueous ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst. The resulting reaction will reduce NOx to elemental nitrogen and water, resulting in NOx concentrations in the exhaust gas from 12.60 ppm (maximum with duct burner) and 9 ppm (without duct burner) to 2.0 ppmv, all 1-hour averages, dry basis at 15% O_2. The ammonia slip will be limited to 5 ppmvd at 15% O_2. Each SCR will be vented through a dedicated stack, which is 18 ft diameter and 140 ft high.

  The exhaust temperature is required to be between 400 and 700 deg F, as specified in condition no. D12.9. The minimum temperature is required to protect the catalyst face from ammonia salt formation and deposition on a cold catalyst. The maximum temperature is required to maintain catalyst effectiveness. The pressure drop across the catalyst shall be between 1.5 and 3.5 inches water column, as required by condition no. D12.10. The ammonia flow rate shall be between 11.8 and 33 gallons per hour, as required by condition no. D12.8.

The following table lists the technical specifications for the SCR.

Table 8 - Selective Catalytic Reduction Specifications

Catalyst Properties	Specifications
Manufacturer	Haldor Topsoe (or equivalent)
Catalyst Description	Titanium/Vanadium/Tungsten, ceramic honeycomb
Catalyst Model No.	DNX GT-201 (or equivalent)
Catalyst Volume	2803.54 ft^3
Reactor Dimensions	46.75 ft long x 2.1 ft wide x 28.75 ft high
Catalyst Guaranteed Life	Vogt Power International—24,000 hrs of operation or three years after initial exhaust flow into the catalyst, whichever occurs first.
Space Velocity	40,450 hr-1
Area Velocity	85,113
Ammonia Injection Rate	11.8 -33 gal/hr
Ammonia Slip	5 ppm at 15% O_2
NOx removal efficiency	> 77%
NOx at stack outlet	2.0 ppmv at 15% O_2
Exhaust Temperature	400 – 700 °F
Pressure Drop	1.5 – 3.5 inches water column

- *Performance and Catalyst Life Warranties*
  - *Performance Warranty*

    Vogt Power International provided guarantees for NOx, CO, and VOC in a letter dated 11/13/12. Mitsubishi Power Systems America provided a guarantee for particulate matter emissions $PM_{10}/PM_{2.5}$. The warranted emissions levels are summarized in the table below.

Table 9 - Warranted Emissions for Control Systems

Pollutants	Warranted Emissions
NOx	2 ppmvd at 15% O_2
CO	2 ppmvd at 15% O_2
VOC	1 ppmvd at 15% O_2
$PM_{10}/PM_{2.5}$	Turbine--4 lb/hr not including fuel-bound sulfur. Duct burner—0.01 lbs/MMBtu (HHV).
NH_3	5 ppmvd at 15% O2 (no guarantee)

For a detailed discussion of the BACT/LAER versus warranty levels, see the BACT/LAER analysis under *Regulation XIII—New Source Review (NSR)* below.

- *Catalyst Life Warranties*
  The Vogt Power International letter indicates the CO and SCR catalysts are guaranteed to meet the guaranteed emissions limits for CO, VOC, and NOx for 24,000 hours of operation or three years after initial exhaust flow into the catalysts, whichever occurs first.

3. A/N 545072--Ammonia Storage Tank

The 12,000-gallon ammonia tank will provide ammonia to the three SCRs. Aqueous ammonia, 19% by weight, will be delivered by tanker truck. The maximum number of deliveries is estimated to be five per month, with each shipment varying between 6000 and 8000 gallons. The filling will take approximately 90 minutes, assuming a 3-inch filling connection between the tanker truck and the RBEP ammonia filling system. To control the filling losses, the tanker truck will connect a filling line and a vapor return line to the RBEP aqueous ammonia unloading system. The vapor return line allows vapors accumulated in the headspace of the aqueous ammonia tank to be returned to the ammonia tanker truck during filling operations.

The tank will be a pressure vessel with a pressure relief valve set at 50 psig. Breathing losses are not expected under normal operating conditions, because the total vapor pressure of 19% aqueous ammonia at 80 deg F is 5.85 psia.

The SCR systems will include an ammonia vaporization/injection skid where the ammonia will be vaporized prior to being injected upstream of the SCR catalyst system. Once the ammonia in injected, it will mix with the exhaust gases upstream of the SCR catalyst.

4. A/N 549120—Oil/Water Separator

The RBEP oil/water separator will treat stormwater from process areas that could potentially include oil or other lubricants for removal of accumulated oil that may result from equipment leakage or small spills and large particulate matter that may be present from equipment washdowns. The residual oil-containing sludge will be collected via vacuum truck and disposed of as hazardous waste.

The oil/water separator will be a single-wall aboveground 3,000-gallon, rectangular, horizontal carbon steel tank, measuring 18 feet long with a width and height of 5 feet, rated at 300 gallons per minute. The removable covers and ports will include gaskets to reduce fugitive emissions. The tank will operate at ambient temperatures and pressure.

The expected annual average precipitation in the project area is 12.02 inches. Based on the areas at RBEP which drain to the oil/water separator, the expected throughput is approximately 82,000 gallons per year.

EMISSIONS CALCULATIONS

Redondo Beach Generating Station—Existing Equipment

- **Potential to Emit Calculations**

  The Boilers No. 5, 6, 7, 8 and 17 emissions in the NSR database were reviewed to determine whether the emissions are representative of the potentials to emit for RBGS. This review indicated that, because of different permitting requirements in the past, the old NSR records are not sufficient to determine whether RBGS is a major source for the purpose of evaluating compliance with regulations, as discussed in the *Rule Evaluation* section below. Consequently, potential to emit emissions calculations are set forth below for Units 5, 6, 7, 8, and Boiler No. 17.

1. Boiler No. 5, 1785 MMBtu/hr
2. Boiler No. 6, 1785 MMBtu/hr

   Operating schedule: 52 wk/yr, 7 days/wk, 24 hr/day = 8760 hr/yr

CO:	500 ppm CO per Rule 1303(b)(2) (permit limit)
NOx:	7 ppmv NOx per Rule 2009 (permit limit)
ROG:	5.5 lb/mmscf per annual emissions reporting (AER) default emission factors for natural gas fired boiler
SOx:	0.6 lb/mmscf per AER default emission factors for natural gas fired boiler
PM/PM_{10}:	7.6 lb PM/mmscf per AER default emission factor for natural gas fired boiler
$PM_{2.5}$:	0.0011 lb/MMBTU—The source test reports for this emission factor are pending final review and approval by the SCAQMD Source Testing Dept.

CO = (1,785,000,000 Btu/hr) (8710 dscf/10^6 Btu)(500 ppm CO/10^6) (20.9/(20.9-3.0)) (28 lbs CO/385 scf for RECLAIM)(8760 hr/yr)(ton/2000 lb) = 2891.3 tpy

NOx = (1,785,000,000 Btu/hr) (8710 dscf/10^6 Btu) (7 ppm/10^6)(20.9/(20.9-3.0)) (46 lbs NOx/385 scf) (8760 hr/yr)(ton/2000 lb) = 66.5 tpy

For combustion emissions, the standard assumption is PM_{10} = PM.

PM_{10} = (1,785,000,000 Btu/hr) (cf/1050 Btu) (7.6 lb PM_{10}/10^6 cf) (8760 hr/yr) (ton/2000 lb) = 56.6 tpy

$PM_{2.5}$ = (1,785 MMBtu/hr) (0.0011 lb $PM_{2.5}$/MMBtu) (8760 hr/yr) (ton/2000 lb) = 8.6 tpy

ROG = (1,785,000,000 Btu/hr) (cf/1050 Btu) (5.5 lb ROG AER/10^6 cf) (8760 hr/yr)(ton/2000 lb) = 41.0 tpy

SOx = (1,785,000,000 Btu/hr) (cf/1050 Btu) (0.6 lb SOx AER/10^6 cf) (8760 hr/yr) (ton/2000 lb) = 4.5 tpy

Combustion of natural gas in the turbines will result in greenhouse gas emissions of CO_2, CH_4, and N_2O. Emission factors for CO_2, CH_4, and N_2O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised November 7, 2011.

CO_2: 53.02 kg CO_2/MMBtu
CH_4 : 1 g CH_4/MMBtu
N_2O: 0.10 g N_2O/MMBtu

CO_2 = (1785 MMBtu/hr)(8760 hr/yr)(53.02 kg/MMBtu)(2.2046 lb/kg)(ton/2000 lb)
= 913,864.6 tpy

CH_4 = (1785 MMBtu/yr)(8760 hr/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g) (ton/2000 lb)
= 17.24 tpy

N_2O = (1785 MMBtu/hr)(8760 hr/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)(ton/2000 lb)
= 1.7 tpy

CO_2e emissions are equal to the sum of the mass emission of each individual GHG adjusted for its global warming potential. Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 78 FR 71948, 11/29/13: *(1)* CH_4 is equivalent to 25 times the global warming potential of CO_2, and *(2)* N_2O is equivalent to 298 times of CO_2.

CO_2e = (913,864.6 tpy CO_2)(1 lb CO_2e/lb CO_2) + (17.24 tpy CH_4)
(25 lb CO_2e/lb CH_4) + (1.7 tpy N_2O)(298 lb CO_2e/lb N_2O) = 914,802.2 tpy

3. Boiler No. 7, 4752.2 MMBtu/hr
4. Boiler No. 8, 4752.2 MMBtu/hr
Operating schedule: 52 wk/yr, 7 days/wk, 24 hr/day = 8760 hr/yr

CO: 2000 ppm CO per Rule 407 (permit limit)
NOx: 5 ppmv NOx per Rule 2009 (permit limit)
ROG: 5.5 lb/mmscf per AER default emission factors for natural gas fired boiler
SOx: 0.6 lb/mmscf per AER default emission factors for natural gas fired boiler
PM/PM_{10}: 7.6 lb PM/mmscf per AER default emission factor for natural gas fired boiler
$PM_{2.5}$: 0.0011 lb/MMBTU—The source test reports for this emission factor are pending final review and approval by the SCAQMD Source Testing Dept.

CO = (4,752,200,000 Btu/hr) (8710 dscf/10^6 Btu)(2000 ppm CO/10^6)
(20.9/(20.9-3.0)) (28 lbs CO/385 scf for RECLAIM)(8760 hr/yr)(ton/2000 lb)
= 30,789.8 tpy

NOx = (4,752,200,000 Btu/hr) (8710 dscf/10^6 Btu) (5 ppm/10^6)(20.9/(20.9-3.0)) (46 lbs NOx/385 scf) (8760 hr/yr)(ton/2000 lb) = 126.5 tpy

For combustion emissions, the standard assumption is PM_{10} = PM.
PM_{10} = (4,752,200,000 Btu/hr) (cf/1050 Btu) (7.6 lb $PM_{10}/10^6$ cf) (8760 hr/yr) (ton/2000 lb) = 150.7 tpy

$PM_{2.5}$ = (4,752.2 MMBtu/hr) (0.0011 lb $PM_{2.5}$/MMBtu) (8760 hr/yr) (ton/2000 lb) = 22.9 tpy

ROG = (4,752,200,000 Btu/hr) (cf/1050 Btu) (5.5 lb ROG AER/10^6 cf) (8760 hr/yr)(ton/2000 lb) = 109.0 tpy

SOx = (4,752,200,000 Btu/hr) (cf/1050 Btu) (0.6 lb SOx AER/10^6 cf) (8760 hr/yr) (ton/2000 lb) = 11.9 tpy

CO_2 = (4,752.2 MMBtu/hr)(8760 hr/yr)(53.02 kg/MMBtu)(2.2046 lb/kg) (ton/2000 lb) = 2,432,978.9 tpy

CH_4 = (4,752.2 MMBtu/yr)(8760 hr/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g) (ton/2000 lb) = 45.9 tpy

N_2O = (4,752.2 MMBtu/hr)(8760 hr/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g) (ton/2000 lb) = 4.59 tpy

CO_2e = (2,432,978.9 tpy CO_2)(1 lb CO_2e/lb CO_2) + (45.9 tpy CH_4) (25 lb CO_2e/lb CH_4) + (4.59 tpy N_2O)(298 lb CO_2e/lb N_2O) = 2,435,494.2 tpy

5. <u>Boiler No. 17, 514.14 MMBtu/hr</u>

CO:	2000 ppm CO per Rule 407 (permit limit)
NOx:	90 ppmv NOx per Rule 2009 (permit limit)
ROG:	5.5 lb/mmscf per AER default emission factors for natural gas fired boiler
SOx:	0.6 lb/mmscf per AER default emission factors for natural gas fired boiler
PM/PM_{10}:	7.6 lb/mmscf per AER default emission factors for natural gas fired boiler
$PM_{2.5}$:	0.0011 lb/MMBTU—The source test reports for this emission factor are pending final review and approval by the SCAQMD Source Testing Dept.

CO = (514,140,000 Btu/hr) (8710 dscf/10^6 Btu)(2000 ppm CO/10^6) (20.9/(20.9 - 3.0)) (28 lbs CO/385 scf for RECLAIM)(8760 hr/yr)(ton/2000 lb) = 3331.2 tpy

NOx = (514,140,000 Btu/hr) (8710 dscf/10^6 Btu) (90 ppm/10^6)(20.9/(20.9 – 3.0))
(46 lbs NOx/385 scf) (8760 hr/yr)(ton/2000 lb)
= 246.3 tpy

For combustion emissions, the standard assumption is PM_{10} = PM.
PM_{10} = (514,140,000 Btu/hr) (cf/1050 Btu) (7.6 lb PM_{10}/10^6 cf)
(8760 hr/yr) (ton/2000 lb) = 16.3 tpy

$PM_{2.5}$ = (514.14 MMBtu/hr) (0.0011 lb $PM_{2.5}$/MMBtu) (8760 hr/yr) (ton/2000 lb)
= 2.5 tpy

ROG = (514,140,000 Btu/hr) (cf/1050 Btu) (5.5 lb ROG AER/10^6 cf)
(8760 hr/yr)(ton/2000 lb) = 11.8 tpy

SOx = (514,140,000 Btu/hr) (cf/1050 Btu) (0.6 lb SOx AER/10^6 cf)
(8760 hr/yr) (ton/2000 lb) = 1.3 tpy

CO_2 = (514.14 MMBtu/hr)(8760 hr/yr)(53.02 kg/MMBtu)(2.2046 lb/kg)
(ton/2000 lb) = 263,223.7 tpy

CH_4 = (514.14 MMBtu/yr)(8760 hr/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g)
(ton/2000 lb) = 5.0 tpy

N_2O = (514.14 MMBtu/hr)(8760 hr/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)
(ton/2000 lb) = 0.5 tpy

CO_2e = (263,223.7 tpy CO_2)(1 lb CO_2e/lb CO2) + (5.0 tpy CH_4)
(25 lb CO_2e/lb CH_4) + (0.5 tpy N_2O)(298 lb CO_2e/lb N_2O)
= 263,497.7 tpy

Table 10 - Potential to Emit Emissions for Redondo Beach Generating Station

	Boiler No. 5	Boiler No. 6	Boiler No. 7	Boiler No. 8	Boiler No. 17	RBGS Total
CO (tpy)	2891.3	2891.3	30,789.8	30,789.8	3331.2	70,693.4
NO_x (tpy)	66.5	66.5	126.5	126.5	246.3	632.3
PM_{10} (tpy)	56.6	56.6	150.7	150.7	16.3	430.9
$PM_{2.5}$ (tpy)	8.6	8.6	22.9	22.9	2.5	65.5
ROG (tpy)	41.0	41.0	109.0	109.0	11.8	311.8
SO_2 (tpy)	4.5	4.5	11.9	11.9	1.3	34.1
CO_2 (tpy)	913,864.6	913,864.6	2,432,978.9	2,432,978.9	263,223.7	6,956,910.7
CH_4 (tpy)	17.24	17.24	45.9	45.9	5.0	131.3

	Boiler No. 5	Boiler No. 6	Boiler No. 7	Boiler No. 8	Boiler No. 17	RBGS Total
N_2O (tpy)	1.7	1.7	4.59	4.59	0.5	13.1
CO_2e (tpy)	914,802.2	914,802.2	2,435,494.2	2,435,494.2	263,497.7	6,964,090.5

- **Actual Emissions**

  Recent actual RBGS emissions are required to evaluate compliance with regulations, as discussed in the *Rule Evaluation* section below.

  In a letter dated 3/22/13, the applicant provided an Excel spreadsheet for RBGS past actual monthly emissions that had been updated from the AFC version to include 2012. In e-mails dated 11/5/13 and 1/9/14, the applicant provided additional information. The table below sets forth the actual emissions for 2011 and 2012, and the 2-year average. The CO_2e emissions have been updated to reflect the most recent global warming potentials, as amended 11/29/13.

Table 11 – Actual Emissions for Redondo Beach Generating Station for 2011 and 2012

		CO	NOx	PM_{10}	$PM_{2.5}$	ROG	SOx	CO_2e
	Year	**Tons/Year**						
Boiler No. 5	**2011**	3.97	3.38	1.06	0.48	1.18	0.13	50,979.52
	2012	0.56	7.14	1.91	0.80	1.97	0.21	85,461.56
2-yr Average		2.27	5.26	1.49	0.64	1.57	0.17	68,220.54
Boiler No. 6	**2011**	3.45	1.55	0.30	0.18	0.45	0.05	19,550.88
	2012	35.69	3.41	0.95	0.41	1.01	0.11	43,854.58
2-yr Average		19.57	2.48	0.62	0.30	0.73	0.08	31,702.73
Boiler No. 7	**2011**	153.11	9.76	2.10	2.17	10.51	1.15	232,094.47
	2012	1.07	16.67	2.18	2.25	10.91	1.19	240,961.88
2-yr Average		77.09	13.21	2.14	2.21	10.71	1.17	236,528.18
Boiler No. 8	**2011**	31.04	1.62	0.06	0.06	0.29	0.03	6360.80
	2012	190.59	2.46	0.39	0.36	1.77	0.19	39,053.23
2-yr Average		110.82	2.04	0.22	0.21	1.03	0.11	22,707.02
Boiler No. 17	**2011**	2.75	4.07	0.25	0.04	0.18	0.02	3969.91
	2012	0.00	0.00	0.00	0.00	0.00	0.00	0
2-yr Average		1.37	2.04	0.12	0.02	0.09	0.01	1984.96
Facility Total	**2011**	194.32	20.38	3.77	2.93	12.61	1.38	312,955.58
	2012	227.91	29.68	5.43	3.82	15.66	1.70	409,331.25
2-yr Average		**211.12**	**25.03**	**4.59**	**3.38**	**14.13**	**1.54**	**361,143.42**

NOx emissions are based on NOx Monthly Reporting Summaries for RECLAIM.

VOC, CO, SO_2 and PM_{10} emissions are based on respective emission factors used in SCAQMD Annual Emissions Reports – 2007 through 2012.

$PM_{2.5}$ emission factor of 0.0011 lb/MMBTU—The source test reports for this emission factor are pending final review and approval by the SCAQMD Source Testing Dept.

CO_2e emissions are based on actual gas usage.

EMISSIONS CALCULATIONS

Redondo Beach Energy Project--New Equipment

1. A/N 545068, 545069, 545070—Combustion Turbine Generators No. 03-A, 03-B, 03-C
   The CTGs will emit combustion emissions consisting of criteria pollutants, toxic pollutants, and greenhouse gases. The three CTGs will have identical emissions.

   A. **Criteria Pollutants**
   The emissions calculations for a power plant are complex because the emissions from the four operational modes must be considered.

   - Worst Case Operating Scenario
     To determine the worst case operating scenario that yields the highest controlled emissions, the applicant provided fifteen operating scenarios corresponding to a full range of possible turbine loads and ambient temperatures, which bound the expected normal operating range of each proposed CTG. The operating scenarios are for four load conditions (100%, 90%, 80%, and 70%) at three ambient temperatures (33 °F, 63.3 °F, and 106 °F), with or without evaporative cooling of the inlet air to the turbines, and with or without duct burner firing for the 100% load cases. The operational emissions rates are based on vendor data. The fifteen scenarios are presented in Table 5.1B.2—MPSA 501DA Performance Data in Appendix 5.1B—Operational and Commissioning Emission Calculations of the AFC.

     In an e-mail dated 10/14/13, the applicant provided VOC hourly emissions rates for the 2 ppmvd at 15% O_2 BACT/LAER level to replace the hourly emissions rate at 1 ppmvd at 15% O_2 on which Table 5.1B.2 was based. (See the BACT/LAER analysis under *Regulation XIII—New Source Review* below for discussion regarding why 2 ppmvd remains the appropriate SCAQMD BACT/LAER limit.)

     The operating scenarios data are summarized in the following table.

Table 12 - Operating Scenarios

Case No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
CTG Load Level (%)	100	100	90	80	70	100	100	90	80	70	100	100	90	80	70
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	On	On	Off	Off	Off	On	On	Off	Off	Off
HRSG Duct Firing	Yes	No	No	No	No	Yes	No	No	No	No	Yes	No	No	No	No
Ambient Conditions															
Ambient Temperature (°F)	33	33	33	33	33	63.3	63.3	63.3	63.3	63.3	106	106	106	106	106
Ambient Relative Humidity (%)	93.8	93.8	93.8	93.8	93.8	75.2	75.2	75.2	75.2	75.2	9.6	9.6	9.6	9.6	9.6
Combustion Turbine Fuel															
CTG Heat Input, MMBtu/hr (LHV)	1324	1324	1202	1078	969	1240	1240	1121	1010	912	1201	1201	997	907	824
CTG Heat Input, MMBtu/hr (HHV)	1492	1492	1354	1214	1092	1398	1398	1262	1138	1028	1353	1353	1123	1022	928
CTG Exhaust Temperature (°F)	996	996	991	996	1027	1010	1010	1007	1013	1044	1017	1017	1028	1034	1067
Duct Burner Fuel															
DB Heat Input, MMBtu/hr (LHV)	450	0	0	0	0	450	0	0	0	0	450	0	0	0	0
DB Heat Input, MMBtu/hr (HHV)	507	0	0	0	0	507	0	0	0	0	507	0	0	0	0
Total Duct Burner Fuel Flow (lb/hr)	21,794	0	0	0	0	21,794	0	0	0	0	21,794	0	0	0	0
Stack Parameters															
Stack Exit Temperature (°F)	398	402.1	393.1	383.9	374.4	395.8	399.7	389.9	381.3	372.6	415.2	405.8	388.1	380.8	374.2
Stack Diameter (ft)	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Stack Flow (10^3 acfm)	1206.5	1205.7	1080.4	957.9	835.9	1141.5	1140.2	1020.9	911.9	800.3	1136.6	1117.9	942.0	853.7	756.3
Stack Exit Velocity (ft/sec)	79.02	78.97	70.76	62.74	54.75	74.76	74.68	66.87	59.72	52.42	74.44	73.22	61.70	55.91	49.54
CTG Outlet/Catalyst Inlet concentrations															
NOx, ppmvd (dry, 15% O2)	12.35	9.0	9.0	9.0	9.0	12.51	9.0	9.0	9.0	9.0	12.6	9.0	9.0	9.0	9.0
CO, ppmvd (dry, 15% O2)	13.24	10.0	10.0	10.0	10.0	13.4	10.0	10.0	10.0	10.0	13.48	10.0	10.0	10.0	10.0
VOC, ppmvd (dry, 15% O2)	2.78	2.0	2.0	2.0	2.0	2.87	2.0	2.0	2.0	2.0	2.92	2.0	2.0	2.0	2.0
Catalyst Outlet/Stack Emissions Rates															
NOx, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	14.26	10.55	9.50	8.52	7.65	13.59	9.89	8.86	7.98	7.19	13.27	9.56	7.87	7.16	6.50
CO, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	8.68	6.42	5.78	5.19	4.65	8.27	6.02	5.39	4.86	4.38	8.08	5.82	4.79	4.36	3.96
VOC, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	4.96	3.67	3.31	2.96	2.66	4.73	3.44	3.08	2.78	2.50	4.62	3.33	2.74	2.49	2.26
$PM_{10}/PM_{2.5}$, CTG + Duct Burner, lb/hr	9.5	4.5	4.5	4.5	4.5	9.5	4.5	4.5	4.5	4.5	9.5	4.5	4.5	4.5	4.5
SO_2 short-term rate (0.75 grains/100 scf), lb/hr[1]	2.63	1.96	1.78	1.60	1.44	2.51	1.84	1.66	1.50	1.35	2.45	1.78	1.48	1.35	1.22
SO_2 long-term rate (0.25 grains/100 scf), lb/hr	0.88	0.65	0.59	0.53	0.48	0.84	0.61	0.55	0.50	0.45	0.82	0.59	0.49	0.45	0.41
SCR NH_3 slip, 5.0 ppmvd (dry, 15% O2) BACT, lb/hr	13.17	9.75	8.78	7.87	7.06	12.56	9.13	8.18	7.37	6.65	12.26	8.84	7.27	6.62	6.01

[1] Southern California Gas Company, Rule No. 30-Transportation of Customer-Owned Gas, allows up to 0.75 gr. S/100 scf total sulfur.

Case 1 (without duct firing) and Case 2 (with duct firing) at 33 °F are the worst case operating scenarios that yield the highest controlled emissions. The emissions rates for NOx, CO, VOC, $PM_{10}/PM_{2.5}$, as well as the short-term SO_2 rate, will be used to calculate the normal operation emissions component for the maximum daily emissions and maximum monthly emissions.

Case 6 (without duct firing) and Case 7 (with duct firing) at 63.3 °F are the worse case operating scenarios that yield the highest emission rates for the average annual temperature. The emissions rates for NOx, CO, VOC, $PM_{10}/PM_{2.5}$, as well as the long-term SO_2 rate, will be used to calculate the normal operation emissions component for maximum annual emissions. Condition B61.4 requires testing to confirm the long-term SO_2 rate of 0.25 grains/100 scf, which is expected to be the average content.

(The air dispersion modeling and health risk assessment analyses discussed below also refers to cases from the above table.)

- <u>Four Operational Modes</u>
  CTGs operate in four operational modes: commissioning, start-up, shutdown, and normal operation. The emissions from the four operating modes are estimated differently.

  The following provides an explanation of the four operating modes, and the proposed parameters and emissions associated with each mode. The applicant has indicated combustor tuning is not required to be evaluated separately because the periodic combustor tuning activities are not expected to result in emissions above either the startup/shutdown or normal operating mode.

  <u>Commissioning</u>
  Commissioning is a one-time event that is performed after the installation of the turbines and associated equipment, and prior to commercial operation. The facility follows a systematic approach to optimize the performance of the CTGs, HRSGs, SCR/CO catalysts, and STG.

  The NOx, CO, and VOC emission rates are expected to be higher during the commissioning period than during normal operations, because the turbines are operated without, or with partial, emission control systems in operation. The total emissions, however, will depend on the load levels, which are less than 100% for some of the commissioning activities. The $PM_{10}/PM_{2.5}$ and SO_2 emission rates are the same as during normal operation, because these pollutants are not controlled by the SCR/CO catalysts.

  The AFC provided the duration and corresponding pollutant emission rates for each commissioning activity for a single CTG in Table 5.1B.1—Summary of Commissioning Emission Estimates included in Appendix 5.1B—Operational and Commissioning

Emission Calculations. In a letter dated March 22, 2013, the applicant provided the fuel use for each commissioning activity for the Huntington Beach Energy Project, which is the same as for the RBEP. The NOx, CO, and VOC emissions during commissioning were estimated based on correspondence with the turbine vendor. The emission estimates are based on the estimated duration of each commissioning event, emission control efficiencies expected for each event, and turbine operating rates.

The following table provides a summary of the commissioning activity parameters and emissions.

Table 13
Commissioning Activity Parameters and Emissions for a Single CTG

Activity	Duration (hr)	CTG Load (%)	Fuel Use MMscf/hr)	Fuel Use (MMscf/Activity)	Total Estimated Emissions per Activity (lbs/turbine) NOx	CO	VOC	SOx[a]	$PM_{10}/PM_{2.5}$[a]
CTG Testing (Full Speed No Load, FSNL)	4	5	0.059	0.235	194.1	6836.5	1535.3	7.9	18.0
Steam Blows[b]	27	50	0.588	15.882	2961.5	85573.6	10074.5	53.0	121.5
Set Unit HRSG & Steam Safety Valves	16	100	1.375	22.008	671.2	454.0	27.4	31.4	72.0
Steam Blows – Restoration					0.0	0.0	0.0	0.0	0.0
DLN Emissions Tuning[c]	12	100	1.375	16.506	125.8	85.1	13.7	23.6	54.0
Emissions Tuning[c]	12	70	1.014	12.165	93.9	63.5	13.7	23.6	54.0
Emissions Tuning[c]	12	100	1.375	16.506	125.8	85.1	13.7	31.6	114.0
Restart CTGs and run HRSG in Bypass Mode. STG Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	40	0.471	5.647	311.7	16470.6	1936.1	23.6	54.0
Restart CTGs and run HRSG in Bypass Mode. STG Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	75	1.073	12.871	98.3	66.5	13.7	23.6	54.0
Restart CTGs and run HRSG in Bypass Mode. STG Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	100	1.375	16.506	125.8	85.1	13.7	23.6	54.0
Verify STG on Turning Gear; Establish Vacuum in ACC Ext Bypass Blowdown to ACC (combined blows) commence tuning on ACC Controls; Finalize Bypass Valve Tuning	12	75	1.073	12.871	98.3	66.5	13.7	23.6	54.0
Verify STG on Turning Gear; Establish Vacuum in ACC Ext Bypass Blowdown to ACC (combined blows) commence tuning on ACC Controls; Finalize Bypass Valve Tuning	12	100	1.375	16.506	125.8	85.1	13.7	23.6	54.0
CT Base Load Testing	12	75	1.073	12.871	98.3	66.5	13.7	23.6	54.0
Pre-STG Roll Outage and Stack Emissions Test Equipment Installation					0.0	0.0	0.0	0.0	0.0
Load Test STG / Combine Cycle (3X1)	24	100	1.375	33.012	251.7	170.2	27.5	47.1	108.0
Combine Cycle testing	24	100	1.375	33.012	396.0	408.0	27.5	47.1	108.0
STG Load Test	24	75	1.073	25.741	196.5	132.9	27.5	47.1	108.0
Commissioning Duct Burners	24	100	1.873	44.941	401.7	410.2	80.4	63.1	228.0
No Operation					0.0	0.0	0.0	0.0	0.0
Install Temporary Emissions Test Equipment					0.0	0.0	0.0	0.0	0.0
Refire Unit with Duct Burners	12	100	1.873	22.471	200.8	205.1	13.7	31.6	114.0
Source Testing & Drift Test Day 1-5 RATA / Pre-performance Testing/ Part 60/75 Certification and Source Testing	168	100	1.375	231.082	1176.0	1191.7	192.5	386.0	1176.0
Water Wash & Performance Preparation	24	100	1.375	33.012	251.7	170.2	27.5	47.1	108.0
Performance Testing	24	100	1.375	33.012	251.7	170.2	27.5	47.1	108.0
CALISO Certification	12	100	1.375	16.506	125.8	85.1	13.7	31.6	114.0
Total	**491**			**633.4**	**8282.4**	**112,881.7**	**14,120.7**	**1060.5**	**2929.5**

[a] SOx and PM emissions are based on the maximum unfired emission rates at 33 F with the exception of Emission Tuning at 100% load, Commissioning Duct Burners, Refire Unit with Duct Burners, half of the Source Testing hours, Performance Testing, and CALISO Certification. For those activities, the maximum fired emission rates at 33 F were used.

[b] Steam blows of the first CTG are expected to last 40 hours at 50% load. It is expected that Steam Blows on the remaining two CTGs will last 20 hours (each) at 50% load.

[c] After commissioning, tuning is expected to occur twice a year.

The applicant requested 491 hours for the commissioning of each CTG. The 491-hour commissioning period is reflected in the table above. The commission for all three units may take up to six months. In an e-mail, dated 10/14/13, the applicant requested the ability to commission all three turbines within the same month to provide AES with the flexibility to make up construction schedule delays by accelerating the commissioning process if necessary.

For the dispersion modeling analysis discussed below, the assumption was made that the maximum impact would occur if all three turbines were simultaneously undergoing commissioning activities with the highest unabated emissions (e.g., initial full-speed, no-load CTG testing, steam blows, HRSG, and steam safety valve settings). The modeling results indicate that all three CTGs may undergo commissioning without causing the NO_2 or CO ambient standards to be exceeded.

Startup of CTGs

A startup event occurs each time a CTG is started up. A startup begins with the initiation of combustion, and concludes when BACT is achieved or the startup is aborted by a trip. During start-up operations, the turbine operates at elevated average concentration rates for NOx, CO, and VOC due to the phased-in effectiveness of the SCR and CO oxidation catalysts.

The MPSA 501DA is equipped with fast start technology and has the ability to reach full power within 10 minutes of initiating a startup. However, the inclusion of the steam generation system (HRSG, STG, and condenser) requires an extended startup period to allow for the gradual heating of the HRSG and steam turbine components.

Three startup scenarios have been developed for RBEP.

1) For a cold start event, the combustion turbine and the steam generation system are all at ambient temperature at the time of the startup, which would typically occur if more than 49 hours elapse between a shutdown event and a system startup event. For the cold start event, the time from fuel initiation until reaching the baseload operating rate is expected to take up to 90 minutes.

2) A <u>warm start event</u> would typically be between 9 and 49 hours from a shutdown event. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 32.5 minutes.

3) A <u>hot start event</u> would typically be within 9 hours of a shutdown event. As with a warm start, the time from fuel initiation until reaching the baseload operating rate is expected to take up to 32.5 minutes.

For daily emissions (for modeling), the applicant has requested a maximum of one cold start and two warm starts per turbine.

For monthly emissions, the applicant has requested a maximum of 5 cold starts per turbine, 25 warm starts per turbine, and 60 hot starts per turbine.

For annual emissions, the applicant has requested a maximum of 24 cold starts per turbine, 150 warm starts per turbine, and 450 hot starts per turbine.

<u>Shutdown of CTGs</u>
A shutdown event occurs each time a CTG is shut down. A shutdown starts at the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. Typically, during the shutdown process, the emission rates will be less than during the start-up process but may be slightly greater than during normal operation because the ammonia injection into the SCR reactor have ceased operation, but the SCR and CO catalysts remain at elevated temperatures and continue controlling for a portion of the shutdown.

The duration of a MPSA 501DA shutdown event is approximately 10 minutes.

For daily emissions (for modeling), the applicant has requested a maximum of three shutdowns per turbine.

For monthly emissions, the applicant has requested a maximum of 90 shutdowns per turbine.

For annual emissions, the applicant has requested a maximum of 624 shutdowns per turbine.

- *<u>Startup/Shutdown Emissions</u>*
  The applicant provided maximum startup and shutdown emissions per event for NOx, CO, and VOC in Table 5.1-13—Facility Startup/Shutdown Emission Rates on pg. 5.1-14 of the AFC. These emissions are based on vendor data and engineering estimates. In an e-mail dated 10/14/13, the applicant indicated that the VOC emissions per event based on 2 ppmvd VOC at 15% O_2 BACT/LAER level is the same as in Table 5.1-13, which was based on 1 ppmvd VOC at 15% O2. The maximum startup and shutdown

emissions rates for SO_2, PM_{10}, and $PM_{2.5}$ are the same as the maximum emissions rates for normal operations presented for Case No. 2 in Table 12 - Operating Scenarios, above.

The following table summarizes the emissions for the three types of startup events and the shutdown event.

Table 14 – Start-up/Shutdown Emission Rates for a Turbine

	Duration Minutes (hr)	NOx lb/event	CO lb/event	VOC lb/event	PM_{10} lb/hr (lb/event)	$PM_{2.5}$ lb/hr (lb/event)	SO_2 lb/hr (lb/event)
Cold Start	90 (1.5)	28.7	115.9	27.9	4.5 (6.75)	4.5 (6.75)	Short-term: 1.96 (2.94) Long-term: 0.65 (0.98)
Warm Start	32.5 (0.542)	16.6	46.0	21.0	4.5 (2.43)	4.5 (2.43)	Short-term: 1.96 (1.06) Long-term: 0.65 (0.35)
Hot Start	32.5 (0.542)	16.6	33.6	20.4	4.5 (2.43)	4.5 (2.43)	Short-term: 1.96 (1.06) Long-term: 0.65 (0.35)
Shutdown	10 (0.167)	9.0	45.3	31.0	4.5 (0.75)	4.5 (0.75)	Short-term: 1.96 (0.33) Long-term: 0.65 (0.11)

To convert $PM_{10}/PM_{2.5}$ and SO_2 hourly rates to lbs/event:

$PM_{10}/PM_{2.5}$, lb/event, cold start = (4.5 lb/hr) (1.5 hr) = 6.75 lb/event
$PM_{10}/PM_{2.5}$, lb/event, warm start & hot start = (4.5 lb/hr) (0.54 hr/warm start & hot start) = 2.43 lb/event
$PM_{10}/PM_{2.5}$, lb/event, shutdown = (4.5 lb/hr) (0.167 hr /shutdown) = 0.75 lb/event

SO_2, lb/event, cold start, short-term = (1.96 lb/hr) (1.5 hr/cold start) = 2.94 lb/event
long-term = (0.65 lb/hr) (1.5 hr/cold start) = 0.98 lb/event

SO_2, lb/event, warm start & hot start, short-term = (1.96 lb/hr)(0.54 hr/warm start & hot start) = 1.06 lb/event
long-term = (0.65 lb/hr) (0.54 hr /warm start & hot start) = 0.35 lb/event

SO_2, lb/event, shutdown, short-term = (1.96 lb/hr) (0.167 hr /shutdown) = 0.33 lb/event
long-term = (0.65 lb/hr) (0.167 hr/shutdown) = 0.11 lb/event

- *Startup/ Shut Down Conditions*
  Condition no. C1.5 provides limits for startups, and condition no. C1.6 provides limits for shutdowns. The limits are necessary because condition nos. A195.5, A195.6, and A195.7 state that BACT for NO_x, CO, and VOC shall not apply during startups and shutdowns. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of startups per day; and (5) duration of cold start, warm start, and hot start; and (6) NOx, CO, and VOC emissions per cold start, warm start, and hot start. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdown; and (3) NOx, CO, and VOC emissions per shutdown.

Normal Operation

Normal operation occurs after the CTGs, HRSGs, SCR/CO catalysts, and STG are working optimally. The emissions during normal operations are assumed to be fully controlled to BACT levels, and exclude emissions due to commissioning, startup and shutdown periods, which are not subject to BACT levels. NOx is controlled to 2.0 ppmvd, CO to 2.0 ppmvd, and VOC to 2.0 ppmvd, all at 15% O2.

For monthly emissions per turbine, the applicant has requested a maximum of: (1) 489.5 hours of operation at 100 percent load, without duct burner firing, and (2) 186 hours of operation at 100 percent, with duct burner firing. The emissions rates will be based on Cases 1 and 2 from Table 12, above. As discussed above, there will be a maximum of 5 cold starts, 25 warm starts, 60 hot starts, and 90 shutdowns.

For annual emissions per turbine, the applicant has requested a maximum of: 1) 5,900 hours of operation at 100 percent load, without duct burner firing, and (2) 470 hours of operation at 100 percent load, with duct burner firing. The emissions rates will be based on Cases 6 and 7 from Table 12, above. As discussed above, there will be a maximum of 24 cold starts, 150 warm starts, 450 hot starts per turbine, and 624 shutdowns.

- *Maximum Daily, Monthly, Annual, NSR Emissions Calculations*

  The following sections will discuss maximum daily emissions, maximum monthly emissions, and maximum annual emissions, as well as associated emission factors and permit condition limits. Finally, offset requirements and the calculation of NSR entries will be discussed.

  - *Maximum Daily Emissions per Turbine*

    Maximum daily emissions during normal operations are calculated to determine whether BACT/LAER is applicable. The BACT/LAER analysis under *Regulation XIII—New Source Review* below explains that the applicability threshold is 1 lb/day increase.

    Commissioning Month

    Maximum daily emissions for the commissioning month are not necessary to be determined because commissioning will take place once during the life of the turbines.

    Normal Operating Month

    In e-mail dated 10/14/13, the applicant provided the breakdown for realistic maximum daily emissions for a normal operating month: 6.2 hours/day for Case 1 duct burner firing and 14.72 hours/day for Case 2 no duct burner firing combined with 1 cold start, 2 warm starts, and 3 shutdowns (3.08 hrs for starts and shutdowns). The normal operation emission rates are from Table 12, and the startup and shutdown emissions per event are from Table 14. The SOx emission rates are the short-term rates.

The maximum controlled daily emissions for normal operations are shown in the table below.

Table 15 - Maximum Daily Emissions, per Turbine

Pollutants	No. of Normal Operating Hrs (Case 1)	Normal Operation Emission Rate, lb/hr (Case 1)	No. of Normal Operating Hrs (Case 2)	Normal Operation Emission Rate, lb/hr (Case 2)	No. of Cold Startups	Lb/cold Startup	No. of Warm Startups	Lb/Warm Startup	No. of Shutdowns	Lbs/ shutdown	Maximum Turbine Daily Emissions lb/day	Maximum Facility Daily Emissions Tons/day
NOx	6.2	14.26	14.72	10.55	1	28.7	2	16.6	3	9.0	**332.61**	**0.50**
CO	6.2	8.68	14.72	6.42	1	115.9	2	46.0	3	45.3	**492.12**	**0.74**
VOC	6.2	4.96	14.72	3.67	1	27.9	2	21.0	3	31.0	**247.67**	**0.37**
$PM_{10}/PM_{2.5}$	6.2	9.5	14.72	4.5	1	6.75	2	2.43	3	0.75	**139.0**	**0.21**
SOx	6.2	2.63	14.72	1.96	1	2.94	2	1.06	3	0.33	**51.21**	**0.08**

Maximum Daily Emissions, lb/day = (no. normal operating hours, Case 1) (normal emission rate, Case 1) + (no. normal operating hours, Case 2) (normal emission rate, Case 2) + (no. startups, cold) (lb/startup, cold) + (no. startups, warm) (lb/startup, warm) + (no. shutdowns) (lb/shutdown)

- *Maximum Monthly Emissions and Emission Factors per Turbine*
  Condition A63.1 specifies the monthly emissions limits for VOC, PM_{10}, and SOx. Typically such a limit is required because Rule 1313(g) requires a monthly emission limit for non-attainment pollutants to establish a basis for calculating offset requirements and to ensure compliance with BACT requirements. As the combined cycle turbines are exempt from offsets per Rule 1304(a)(2), the monthly emissions limits are included to demonstrate that the equipment will meet BACT. A monthly limit is not required for CO because it is in attainment and not a precursor to any nonattainment pollutant. A monthly limit is not required for NOx because the number of RECLAIM RTCs required are determined on an annual basis which will be reflected in conditions I297.1, I297.3, and I297.5 for the turbines, and I297.2, I297.4, and I297.6 for the associated duct burners.

  The maximum monthly emissions and 30-day averages for each pollutant are based on the higher of the commissioning month emissions versus the normal operating month emissions. Therefore the commissioning month emissions and normal operating month emissions will be evaluated below. In addition, the commissioning emission factors and normal operating emission factors will be included as appropriate in condition A63.1 for VOC, PM_{10}, and SOx. The commissioning emission factor and the post-commissioning/pre-CEMS certification emission factor will be including in conditions A99.1 and A99.2, respectively, for NOx.

  - Commissioning Month
    - Maximum Monthly Emissions, Commissioning
      In an e-mail dated 10/14/13, the applicant clarified that the first month of emissions should be based on commissioning only. There will be no normal operating days. The

total commissioning emissions, taken from Table 13 above, are shown in the table below.

Table 16 – Maximum Monthly Emissions, Commissioning, per Turbine

Pollutants	Commissioning Emissions, lb/month
NOx	8282.4
CO	112,881.7
VOC	14,120.7
$PM_{10}/PM_{2.5}$	2929.5
SOx	1060.5

- Commissioning Emission Factors
  The commissioning period emission factors are examined for inclusion in condition no. A63.1 for VOC, PM_{10}, and SOx, and in condition no. A99.1 for NOx. As explained in the Rule 2012 analysis below, condition A99.1 specifies the interim emission factor for NOx for the commissioning period during which the CTGs are assumed to be operating at uncontrolled levels. For each pollutant, the emission factor is the total emissions for the commissioning period divided by the total fuel usage for the commissioning period, both of which are from Table 13, above. The table below shows the calculation of the emissions factors.

Table 17 - Commissioning Emission Factors

Pollutant	Total Commissioning Emissions, lb	Total Commissioning Fuel Usage, mmcf	Emission Factor, lb/mmcf
NOx	8282.4	633.4	**13.08**
VOC	14,120.7	633.4	**22.29**
$PM_{10}/PM_{2.5}$	2929.5	633.4	**4.63**
SOx	1060.5	633.4	**1.68**

- Normal Operating Month
  - Maximum Normal Operating Month Emissions
    In an e-mail dated 10/14/13, the applicant clarified that the second month of emissions should be based on a normal operating month, with no commissioning carry over. The maximum controlled normal operating month emissions are shown in the table below.

    For maximum monthly emissions per turbine, the applicant has requested: (1) 186 hours of operation at 100 percent for Case 1 with duct burner firing , (2) 489.5 hours of operation at 100 percent load for Case 2 without duct burner firing, (3) 5 cold starts, (4) 25 warm starts, (5) 60 hot starts, and (7) 90 shutdowns. The normal operation emission rates for Cases 1 and 2 are from Table 12, and the startup and shutdown emissions per event are from Table 14. The SO_x emission rates are the short-term rates.

Table 18 - Maximum Monthly Emissions, Normal Operations, per Turbine

Pollutants	No. of Normal Operating Hrs (Case 1)	Normal Operation Emission Rate, lb/hr (Case 1)	No. of Normal Operating Hrs (Case 2)	Normal Operation Emission Rate, lb/hr (Case 2)	No. of Cold Startups	lb/cold startup	No. of Warm Startups	lb/warm startup	No. of Hot Startups	lb/hot startup	No. of Shut downs	lb/shutdown	Maximum Turbine Monthly Emissions lb/month	Maximum Facility Monthly Emissions Tons/month
NOx	186	14.26	489.5	10.55	5	28.7	25	16.6	60	16.6	90	9.0	**10,181.09**	**15.27**
CO	186	8.68	489.5	6.42	5	115.9	25	46.0	60	33.6	90	45.3	**12,579.57**	**18.87**
VOC	186	4.96	489.5	3.67	5	27.9	25	21.0	60	20.4	90	31.0	**7,397.53**	**11.10**
$PM_{10}/PM_{2.5}$	186	9.5	489.5	4.5	5	6.75	25	2.43	60	2.43	90	0.75	**4277.55**	**6.42**
SOx	186	2.63	489.5	1.96	5	2.94	25	1.06	60	1.06	90	0.33	**1,583.10**	**2.37**

Maximum Monthly Emissions, lb/month = (no. normal operating hours, Case 1) (normal emission rate, Case 1) + (no. normal operating hours, Case 2) (normal emission rate, Case 2) + (no. startups, cold) (lb/startup, cold) + (no. startups, warm) (lb/startup, warm) + (no. startups, hot) (lb/startup, hot) + (no. shutdowns) (lb/shutdown)

The public notice will include a table of maximum monthly emissions for the facility for normal operations. NOx, CO, VOC, $PM_{10}/PM_{2.5}$, and SOx emissions will be from the table above. For ammonia, the maximum annual emissions are 85,844 lb/yr per turbine from Table 24—Toxic Air Contaminants/Hazardous Air Pollutants per Turbine below. For the facility, the maximum annual emissions for ammonia are 128.77 tpy, the maximum monthly emissions are 10.73 tpy, and the maximum daily emissions are 0.36 tpy.

- <u>Normal Operating Month Emission Factors</u>
  The normal operating emission factors are examined for inclusion in condition no. A63.1 for VOC, PM_{10}, and SOx, and in A99.2 for NOx. As explained in the Rule 2012 analysis below, condition A99.2 specifies the interim emission factor for the normal operating period after commissioning has been completed but before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels.

  The normal operating month emission factors are shown in the table below.

Table 19 - Normal Operating Emission Factors

Pollutants	Maximum Monthly Emissions, lb/month	Emission Factors, lb/mmcf
NOx	10,181.09	8.88
CO	12,579.57	10.97
VOC	7,397.53	6.45
PM_{10}	4,277.55	3.73
SOx	1,583.10	1.38

To calculate emission factors:

Total fuel consumption in a month = (maximum monthly heat input) * (mmscf/1050 MMBtu)
= (1,204,245.56 MMBtu/month) (mmscf /1050 MMBtu) = 1146.90 mmscf/month

Where maximum monthly heat input =

{[186 hr, Case 1] * [(1492 MMBtu/hr (CTG) + 507 MMBtu/hr (duct burner)]} +

{[(489.5 hr, Case 2) + (5 cold starts)(1.5 hr /cold start) + (25 warm starts) (0.54 hr/warm start) + (60 hot starts)(0.54 hr/hot start) + (90 shutdowns)(0.167 hr/ shutdown)] x (1492 MMBtu/hr (CTG)]}

= 1,204,245.56 MMBtu/month

Emission factor = (lb/month) (month/1146.90 mmscf)

- Permit Conditions—Monthly Emissions Limits
Condition A63.1 specifies the maximum monthly emissions limits per turbine for VOC, PM_{10}, and SOx. The maximum monthly emissions and 30-day averages for each pollutant are based on the higher of the commissioning month emissions versus the normal operating month emissions. (The higher values are in bold font in the table below.) Although condition A63.1 will not include a monthly limit for CO and NOx, these pollutants are included in the table below because the determination of 30-day averages for all pollutants is required for the NSR Data Summary Sheet. In addition, the 30-day averages for the RBEP (3 turbines) are included in the table below.

Table 20 – Maximum Monthly Emissions and Thirty-Day Averages

Pollutants	Commissioning 30-Day Averages per Turbine, lb/day	Normal Operations 30-Day Averages per Turbine, lb/day	Condition A63.1 Limits per Turbine, lb/month	30-Day Averages per Turbine lb/day	RBEP 30-Day Averages, lb/day
NOx	8282.4/30 = 276.08	**10,181.09/30 = 339.37**		339.37	1018.11
CO	**112,881.7/30 = 3762.72**	12,579.57/30 = 419.32		3762.72	11,288.16
VOC	**14,120.7/30 = 470.69**	7,397.53/30 = 246.58	14,121	470.69	1412.07
PM_{10}	2929.5/30 = 97.65	**4,277.55/30 = 142.59**	4278	142.59	427.77
SOx	1060.5/30 = 35.35	**1,583.10/30 = 52.77**	1583	52.77	158.31

Condition A63.1 will limit VOC emissions to 14,121 lb/month, and PM_{10} to 4278 lb/month, SOx to 1583 lb/month. The commissioning emission factors are 22.29 lb/mmcf for VOC, 4.63 lb/mmcf for PM_{10}, and 1.68 lb/mmcf for SOx from Table 17.

The normal operating emission factors are 6.45 lb/mmcf for VOC, 3.73 lb/mmcf for PM_{10}, and 1.38 lb/mmcf for SOx from Table 19.

- *Maximum Annual Emissions per Turbine*
  The annual emissions for the commissioning year and a normal operating year are calculated below. The number of RECLAIM NOx RTCs required are determined on an annual basis which will be reflected in conditions I297.1 - I297.6, as discussed under the *Rule 2005(c)(2)* analysis below.

  - Commissioning Year
    The maximum commissioning year emissions are calculated by adding the maximum commissioning month emissions from Table 16 to emissions for eleven months of the maximum annual emissions for normal operations from Table 22, below.

Table 21 – Maximum Annual Emissions, Commissioning Year, per Turbine

Pollutants	Commissioning Year Emissions, lb/yr
NOx	8282.4 lb/commissioning month + (11/12 months) (81,003.1 lb/yr) = **82,535.2 lb/yr (41.3 tpy)**
CO	112,881.7 lb/commissioning month + (11/12 months) (92,473.7 lb/yr) = **197,649.3 lb/yr (98.8 tpy)**
VOC	14,120.7 lb/commissioning month + (11/12 months) (54,862.7 lb/yr) = **64,411.5 lb/yr (32.2 tpy)**
PM_{10}	2929.5 lb/commissioning month + (11/12 months) (33,103.0 lb/yr) = **33,273.9 lb/yr (16.6 tpy)**
SOx	1060.5 lb/commissioning month + (11/12 months) (4296 lb/yr) = 4998.5 **lb/yr (2.5 tpy)**

  - Normal Operating Year
    For maximum annual emissions per turbine, the applicant has requested: (1) 470 hours of operation at 100 percent for Case 6 with duct burner firing, (2) 5900 hours of operation at 100 percent load for Case 7 without duct burner firing, (3) 24 cold starts, (4) 150 warm starts, (5) 450 hot starts, and (7) 624 shutdowns. The normal operation emission rates for Cases 6 and 7 are from Table 12, and the startup and shutdown emissions per event are from Table 14. The SOx emission rates are the long-term rates.

    Table 22 presents the maximum annual emissions per turbine, and Table 23 presents the maximum annual emissions per facility for a normal operating year.

Table 22 - Maximum Annual Emissions, Normal Operations, per Turbine

Pollutants	No. of Normal Operating Hrs (Case 6)	Normal Operation Emission Rate, lb/hr (Case 6)	No. of Normal Operating Hrs (Case 7)	Normal Operation Emission Rate, lb/hr (Case 7)	No. of Cold Startups	lb/cold startup	No. of Warm Startups	lb/warm startup	No. of Hot Startups	lb/hot startup	No. of Shut downs	lb/shutdown	Maximum Annual Emissions lb/yr (tpy)
NOx	470	13.59	5900	9.89	24	28.7	150	16.6	450	16.6	624	9.0	**81,003.1 (40.50)**
CO	470	8.27	5900	6.02	24	115.9	150	46.0	450	33.6	624	45.3	**92,473.7 (46.24)**
VOC	470	4.73	5900	3.44	24	27.9	150	21.0	450	20.4	624	31.0	**54,862.7 (27.43)**
$PM_{10}/PM_{2.5}$	470	9.5	5900	4.5	24	6.75	150	2.43	450	2.43	624	0.75	**33,103.0 (16.55)**
SOx	470	0.84	5900	0.61	24	0.98	150	0.35	450	0.35	624	0.11	**4296.0 (2.15)**

Maximum Annual Emissions, lb/yr = (no. normal operating hours, Case 6) (normal emission rate, Case 6) + (no. normal operating hours, Case 7) (normal emission rate, Case 7) + (no. startups, cold) (lb/startup, cold) + (no. startups, warm) (lb/startup, warm) + (no. startups, hot) (lb/startup, hot) + (no. shutdowns) (lb/shutdown)

Table 23 - Maximum Annual Emissions, Normal Operations, Facility

Pollutants	Facility Maximum Annual Emissions lb/yr (tpy)
NOx	81,003.1 lb/yr-turbine * 3 turbines = **243,009.3 lb/yr** (40.50 ton/yr-turbine * 3 turbines = **121.5 tpy**)
CO	92,473.7 lb/yr-turbine * 3 turbines = **277,421.1 lb/yr** (46.24 ton/yr-turbine * 3 turbines = **138.7 tpy**)
VOC	54,862.7 lb/yr-turbine * 3 turbines = **164,588.1 lb/yr** (27.43 ton/yr-turbine * 3 turbines = **82.3 tpy**)
$PM_{10}/PM_{2.5}$	33,103.0 lb/yr-turbine *3 turbines = **99,309.0 lb/yr** (16.55 ton/yr-turbine * 3 turbines = **49.65 tpy**)
SOx	4296.0 lb/yr-turbine * 3 turbines = **12,888.0 lb/yr** (2.15 ton/yr-turbine * 3 turbines = **6.45 tpy**)

- Permit Conditions—Annual Emissions Limits

  Unless limited by permit condition, the annual emissions are the monthly emissions in condition A63.1 multiplied by twelve months. Condition A63.1 limits each turbine to 6835 hours per year, including startups and shutdowns, but not commissioning, based on the requested annual schedule of 6835 hours.

  [470 hours of operation, Case 6) + (5900 hours, Case 7) + (24 cold starts * 1.5 hr/cold start) + (150 warm starts * 0.542 hr/warm start) + (450 hot starts * 0.542 hr/hot start) + (624 shutdowns * 0.167 hr/shutdown) = 6835 hr/yr]

- *New Source Review (NSR) Database Entries*
  This section develops the NSR database entries.

  Operating Schedule: 52 wks/yr, 7 days/wk, 24 hrs/day (annualized schedule)

  The 30-day averages per turbine are from Table 20. The uncontrolled emissions (R1) and controlled emissions (R2) are back calculated from the 30-day averages and used for the purpose of input for NSR Data Summary Sheet only.

  NOx
  R2 = (339.37 lb/day)(day/24 hr) = 14.14 lb/hr

  R1 = (14.14 lb/hr)(9 ppm uncontrolled/2 ppm controlled per case 2) = 63.63 lb/hr

  30-DA = 339.37 lb/day

  CO
  R2 = (3762.72 lb/day)(day/24 hr) = 156.78 lb/hr

  R1 = (156.78 lb/hr)(10 ppm uncontrolled/2 ppm controlled per case 2) = 783.90 lb/hr

  30-DA = 3762.72 lb/day

  ROG
  R2 = R1 (0% control efficiency per case 2)

  R2 = R1 = (470.69 lb/day)(day/24 hr) = 19.61 lb/hr

  30-DA = 470.69 lb/day

  PM_{10}
  R2 = R1 = (142.59 lb/day)(day/24 hr) = 5.94 lb/hr

  30-DA = 142.59 lb/day

  SOx
  R2 = R1 = (52.77 lb/day)(day/24 hr) = 2.20 lb/hr

  30-DA = 52.77 lb/day

B. Toxic Pollutants
The applicant provided revised toxic air pollutant (TAC) and hazardous air pollutant (HAP) emissions for each turbine with duct burner in Response Letter No. 2, dated 3/15/13, item 3.b., Table 5.1B.5bR on pg. 4. The emission rates were revised to be based on US EPA AP-42

emission factors as required by the SCAQMD. The emissions rates are for use in the Rule 1401 health risk assessment below.

Table 24 - Toxic Air Contaminants/Hazardous Air Pollutants per Turbine

Compound	CAS	TAC/HAP	Emission Factor [1] (Lb/MMBtu)	Lb/hr	Lb/yr	TPY
Ammonia[2]	766417	TAC		13.2	85,844	42.92
Acetaldehyde	75070	TAC & HAP	4.0E-05	0.080	392	0.20
Acrolein	107028	HAP & TAC	6.4E-06	0.013	63	0.03
Benzene	71432	HAP & TAC	1.2E-05	0.024	117	0.06
1,3-Butadiene	106990	HAP & TAC	4.3E-07	0.00086	4.21	0.002
Ethylbenzene	100414	HAP & TAC	3.2E-05	0.064	313	0.16
Formaldehyde[3]	50000	HAP & TAC	3.6E-04	0.719	3525.7	1.76
Hexane	110543	HAP & TAC	Not available	N/A	N/A	
Naphthalene	91203	HAP & TAC	1.3E-06	0.0026	12.7	0.01
PAHS	1151	HAP & TAC	2.2E-06 – 1.3E-06 = 0.90E-06[4]	0.0018	8.8	0.004
Propylene (propene)	115071	TAC	Not available	N/A	N/A	
Propylene Oxide	75569	HAP & TAC	2.9E-05	0.058	284	0.14
Toluene	108883	HAP & TAC	1.3E-04	0.260	1273	0.64
Xylene	1330207	HAP & TAC	6.4E-05	0.128	627	0.31
Total Annual HAPS Emissions per Turbine, TPY					**6620**	**3.31**

1 Emission factors based on AP-42, Section 3.1, Final Section, Table 3.1-3 Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbine (Uncontrolled), April 2000, unless otherwise noted.

2 Ammonia and propylene are toxic air contaminants for the purpose of Rule 1401, but not federal hazardous air pollutants.

3 Formaldehyde emission factor based on AP-42, Section 3.1, Background Information, Table 3.4-1-- Summary of Emission Factors for Natural Gas-Fired Gas Turbines, for formaldehyde controlled by CO catalyst, April 2000.

4 Carcinogenic PAHs only. Naphthalene was subtracted from the total PAHs and considered separately in the HRA.

The hourly and annual emissions are calculated as follows:

<u>For compounds other than ammonia</u>
Hourly emissions, lb/hr = (Emission Factor) (maximum hourly heat input rate of 1999 MMBtu/hr)

Where maximum hourly heat input rate is the maximum hourly heat input with duct burner firing = 1492 MMBtu/hr (CTG) + 507 MMBtu/hr (duct burner) = 1999 MMBtu/hr [Case 1]

Annual emissions, lb/yr = (Emission Factor) (average annual heat input rate of 9,793,620 MMBtu/yr)

Where average annual heat input rate is based on 6,365 hrs of turbine operation without duct burner firing [5900 hr + 360 hr startup + 105 hr shutdown] with an average annual heat input of 1,398 MMBtu/hr (HHV)[Case 7] and 470 hours of turbine operation with duct burner firing with an average annual heat input of 1905 MMBtu/hr [1398 MMBtu/hr (CTG) + 507 MMBtu/hr (duct burner) (HHV)]) [Case 6] .

Average annual heat input = (6,365 hr)(1398 MMBtu/hr) + (470 hr)(1905 MMBtu/hr) = 9,793,620 MMBtu/yr

For ammonia

Maximum hourly emissions, lb/hr = (1999 MMBtu/hr, Case 1) (8710 dscf/10^6 Btu) (4.86 ppm NH_3 /10^6) (20.9/(20.9-15.0)) (17 lbs NH_3/385 scf) = 13.2 lb /hr

Note: In Table 12, the ammonia slip is 13.17 lb/hr for Case 1 which is the highest of all 15 cases.

Annual emissions, lb/yr = (Average hourly emissions, lb/hr) (Annual operating hours) = (12.56 lb/hr) (6835 hr/yr) = 85,844 lb/yr

Where the average hourly emissions, lb/hr = (1905 MMBtu/hr, Case 6) (8710 dscf/10^6 Btu) (4.86 ppm NH_3 /10^6) (20.9/(20.9-15.0)) (17 lbs NH_3 /385 scf) = 12.56 lb /hr

Annual operating hours = 5900 hr (normal operating) + 470 hr (start-ups) + 465 hr (shutdowns) = 6835 hr

Note: The above annual emissions estimate is conservative because ammonia is not injected during an entire start-up and shutdown.

C. Greenhouse Gases (GHG)

- *Combustion: CO_2, CH_4, N_2O*

  Combustion of natural gas in the turbines will result in emissions of CO_2, CH_4, and N_2O.

  As shown above for toxic compounds other than ammonia:

  Average annual heat input = (6,365 hr)(1398 MMBtu/hr) + (470 hr)(1905 MMBtu/hr) = 9,793,620 MMBtu/yr

  Emission factors for CO_2, CH_4, and N_2O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised November 7, 2011.

For <u>each</u> turbine with duct burner:

CO_2: 53.02 kg CO_2/MMBtu
CH_4 : 1 g CH_4/MMBtu
N_2O: 0.10 g N_2O/MMBtu

CO_2 = (9,793,620 MMBtu/yr)(53.02 kg/MMBtu)(2.2046 lb/kg)
= 1,144,755,597.0 lb/yr = 572,377.8 tpy

CH_4 = (9,793,620 MMBtu/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 21,594.9 lb/yr = 10.8 tpy

N_2O = (9,793,620 MMBtu/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 2159.5 lb/yr = 1.1 tpy

Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 78 FR 71948, 11/29/13: *(1)* CH_4 is equivalent to 25 times the global warming potential of CO_2, and *(2)* N_2O is equivalent to 298 times of CO_2.

CO_2e = (572,377.8 tpy CO_2)(1 lb CO_2e/lb CO2) + (10.8 tpy CH_4)
(25 lb CO2e/lb CH_4) + (1.1 tpy N_2O)(298 lb CO_2e/lb N_2O)
= 572,975.6 tpy per turbine

Table 25 – Greenhouse Gases per Turbine and Facility

	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
Turbine No. 03-A	572,377.8	10.8	1.1	572,975.6
Turbine No. 03-B	572,377.8	10.8	1.1	572,975.6
Turbine No. 03-C	572,377.8	10.8	1.1	572,975.6
Facility	1,717,133.4	32.4	3.3	1,718,926.8

- *<u>Circuit Breakers: SF6</u>*
  Condition F52.2 will include a CO_2e annual limit for SF_6 to enforce the BACT requirements for the circuit breakers.

  Gas Turbine No. 03-A—13.8-kilovolt circuit breaker, 24 lb SF_6
  Gas Turbine No. 03-B --13.8-kilovolt circuit breaker, 24 lb SF_6
  Gas Turbine No. 03-C --13.8-kilovolt circuit breaker, 24 lb SF_6
  Steam Turbine Generator No. 03-ST1-- 13.8-kilovolt circuit breaker, 24 lb SF_6

  Electrical connection line—230-kilovolt circuit breaker, 216 lb SF_6

Annual leakage = [(3 gas turbines)(24 lb SF_6/gas turbine) + (1 steam turbine) (24 lb SF_6/steam turbine) + (electrical connection line) (216 lb SF_6/line)] * [0.5/100 leakage] = 1.56 lb/yr SF_6

Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 78 FR 71948, 11/29/13, SF_6 is equivalent to 22,800 times the global warming potential of CO_2.

(1.56 lb/yr SF_6)(22,800 lb CO_2e/lb SF_6) = 37,284 lb/yr = 17.8 tpy CO_2e

- *Facility, CO_2e*
  Annual = 1,718,926.8 tpy (three turbines) + 17.8 tpy (circuit breakers) = 1,718,944.60 tpy
  Monthly = (1,718,944.60 tons/yr) (yr/12 months) = 143,245.38 tons/month
  Daily = (143,245.38 tons/month)(month/30 days) = 4774.85 ton/day

2. A/N 545066, 545067, 545071—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 03-A, 03-B, 03-C
   Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

   A. Criteria Pollutants
      NOx = CO = VOC = PM_{10} = SOx = 0 lb/hr = 0 lb/day

   B. Toxic Pollutants
      From Table 24 above, the 5 ppmvd BACT level for ammonia results in an annual emission rate of 85,844 lb/yr.

      To calculate R1 and R2 for annualized operating schedule (52 wk/yr, 7 days/wk, 24 hr/day, same as CTGs)

      NH_3, lb/day = (85,844 lb/yr) (yr/52 wk) (wk/7 days) = 235.8 lb/day
      lb/hr = (235.8 lb/day) (day/24 hr) = 9.83 lb/hr
      30-DA = (85,844 lb/yr)(yr/12 months)(month/30 days) = 238.46 lb/day

      Note: Ammonia is not a federal HAP.

3. A/N 545072—Ammonia Storage Tank
   Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

   No emissions are expected because the filling losses will be controlled by a vapor return line and the breathing losses by the 50 psig pressure valve.

   NH_3 = 0 lb/hr = 0 lb/day

4. A/N 549120—Oil/Water Separator
   Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

   The applicant provided emissions calculations as follows:

   Expected throughput is 82,000 gallons/yr.
   Controlled emission factor = 0.2 lb VOC/1000 gal waste water for covered separators per AP-42, Table 5.1-2—Fugitive Emission Factors for Petroleum Refineries.

   To determine maximum monthly emissions, assume 25% of annual rainfall occurs in one month.

   VOC = (0.25 x 82,000 gal/yr) (0.2 lb VOC/1000 gal) (month/30 days) (day/24 hr)
   = 0.006 lb/hr → 0.01 lb/hr

   VOC, lb/day = (0.01 lb/hr)(24 hr/day) = 0.24 lb/day
   30-DA = 0.24 lb/day

RULE EVALUATION
The RBEP project is expected to comply with all applicable SCAQMD rules and regulations, and federal and state regulations, as follows:

DISTRICT RULES AND REGULATIONS
Rule 205—Expiration of Permit to Construct
Rule 205—This rule provides that a permit to construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer. This requirement is set forth in condition 1.b in Section E: Administrative Conditions of the facility permit.

40 Part 52.21(r)(2) and Rule 1713(c) also provide expiration requirements for permits to construct.

- 40 Part 52.21--Rule 1714(c) incorporates by reference the provisions of 40 Part 52.21--Prevention of Significant Deterioration of Air Quality. Part 52.21(r)(2) states: "Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date."

  Accordingly, condition E193.8 provides that the Permit to Construct shall become invalid if construction is not commenced within 18 months after the issuance date, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The EPA Administrator may extend the 18-month period if a proper showing is made.

- Rule 1713, adopted 10/7/88--Rule 1713(c) states: "A permit to construct shall become invalid if construction is not commenced within 24 months after receipt of such approval, if construction is discontinued for a period of 24 months or more, or if construction is not completed within a reasonable time. The Executive Officer may extend the 24-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 24 months of the projected and approve commencement date."

  Thus Rule 1713(c) is the same as Part 52.21(r)(2), with two exceptions. Rule 1713(c) allows a period of 24 months and extension by the Executive Officer. Condition E193.9 incorporates these requirements.

Rule 212—Standards for Approving Permits
***Rule 2005(h) –Public Notice for RECLAIM** (requires compliance with Rule 212)*
Public notice **is** required for this project, as discussed below.

- ***Rule 212(c)(1)***
  Public notice is required for any new or modified equipment under Regulation XXX (Title V) that may emit air contaminants located within 1000 feet from the outer boundary of a school, unless the modification will result in a reduction of emissions of air contaminants from the facility and no increase in health risk at any receptor location.

  This subsection does **not** require public notice because the proposed equipment will **not** be located within 1000 feet of the outer boundary of a school. The nearest K-12 school—Redondo Union High School, 631 Vincent Park, Redondo Beach--is located 2300 ft away, according to SCAQMD PRA (modeling) staff based on Google Earth.

- ***Rule 212(c)(2)***
  Public notice is required for any new or modified facility which has on-site emission increases exceeding any of the daily maximums specified in subdivision (g) of this rule.

  This subsection requires public notice because the on-site emission increases from the RBEP will exceed the daily maximum thresholds set forth in subdivision (g) for VOC, NOx, PM10, SOx, and CO, as shown below.

Table 26--Rule 212(c)(2) Applicability

	VOC	NOx	PM_{10}	SOx	CO	Lead
RBEP 30-day averages, lb/day (*Table 20*)	1412.07	1018.11	427.77	158.31	11,288.16	0
Rule 212(c)(2) Daily Maximum, lbs/day	30	40	30	60	220	3
Increase Exceed Daily Maximum?	Yes	Yes	Yes	Yes	Yes	Yes

The public notice requirements for subdivision (c)(2) are found in subdivisions (d) and (g). The District will prepare the public notice that will contain sufficient information to fully describe the project. In accordance with subdivision (d), the applicant will be required to distribute the public notice to each address within ¼ mile radius of the project.

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

Pursuant to (g)(1), the District will make the following information available for public inspection at Redondo Beach Public Library located at 303 N. Pacific Coast Highway, Redondo Beach, CA 90277 during the 30-day comment period: (1) public notice, (2) project information submitted by the applicant, and the (3) District's permit to construct evaluation.

Pursuant to (g)(2), the public notice will be published in a newspaper which serves the area that will be impacted by the project (Daily Breeze).

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

The Rule 212(c)(2) public notice will be combined with the Rule 3006 Title V public notice for a single public notice, with the public notice periods running concurrently for a single 30-day public comment period. (The Title V public notice requirements are discussed below under *Regulation XXX – Title V*.)

- ***Rule 212(c)(3)***
  Public notice is required for any new or modified equipment under Regulation XX or XXX with increases in emissions of toxic contaminants for which a person may be exposed to a maximum individual cancer risk greater than, or equal to one in a million during a lifetime (70 years) for facilities with more than one permitted unit, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million using the risk assessment procedures and toxic air contaminants specified under Rule 1402.

This subsection does **not** require public notice because the increase in toxic emissions from each combustion turbine will not expose a person to a maximum individual cancer risk that is greater than or equal to one in a million, as demonstrated by the Rule 1401 risk assessment discussed below.

Rule 218 – Continuous Emission Monitoring

A CO CEMS will be required to be installed on each CTG to verify compliance with the CO emission limits. In accordance with paragraphs (c), (e), (f), the facility is required to submit an "Application for CEMS" for each CO CEMS and to adhere to retention of records requirements and reporting requirements once approval to operate the CO CEMS is granted. Compliance with this rule is expected.

Rule 401 – Visible Emissions

This rule prohibits the discharge of visible emissions for a period aggregating more than three minutes in any one hour which is as dark or darker in shade than Ringelmann No. 1. Visible emissions are not expected from the gas turbines because they will be firing exclusively on pipeline quality natural gas.

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. Nuisance problems are not expected from the CTGs and auxiliary equipment under normal operation.

Rule 407 – Liquid and Gaseous Air Contaminants

This rule limits the gas turbines to 2000 ppmv CO. The CO emissions from the turbines will be controlled by an oxidation catalyst to the BACT/LAER limit of 2 ppmvd at 15% O2. The SO_2 portion of the rule does not apply per subdivision (c)(2), because the natural gas fired in the CTGs will comply with the sulfur limit in Rule 431.1. Therefore, compliance with this rule is expected.

Rule 409 – Combustion Contaminants

This rule restricts the combustion generated PM emissions from the gas turbines to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes. Each gas turbine is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the grain loading is expected to be 0.009 gr/scf.

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

where:

A = Maximum PM_{10} emission rate during normal operation, 9.5 lb/hr
(4.5 lb/hr per turbine + 5 lb/hr per duct burner = 9.5 lb/hr)

B = Rule specified percent of CO_2 in the exhaust (12%)
C = Percent of CO_2 in the exhaust (approx. 4.29% for natural gas)
D = Stack exhaust flow rate, scf/hr

$$D = F_d * \frac{20.9}{(20.9 - \%\ O_2)} * TFD = 8710 * \frac{20.9}{17.9} * 1999 = 20.3\ E{+}06\ scf/hr$$

where:

F_d = Dry F factor for fuel type, 8710 dscf/MMBtu
O_2 = Rule specific dry oxygen content in the effluent stream, 3%
TFD = Total fired duty measured at HHV, 1999 MMBTU/hr
(1492 MMBtu/hr per turbine + 507 MMBtu/hr per duct burner)

Grain Loading = [(9.5 * 12) / (4.29) (20.3 E+06)] * 7000 = 0.009 gr/scf < 0.1 gr/scf limit

Rule 431.1 – Sulfur Content of Gaseous Fuels

The natural gas supplied to the gas turbine is expected to comply with the 16 ppmv sulfur limit (calculated as H_2S) specified in this rule, because commercial grade natural gas has an average sulfur content of 4 ppm.

Rule 474—Fuel Burning Equipment-Oxides of Nitrogen

This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

Rule 475 – Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976, and establishes a limit for combustion contaminants (particulate matter) of 11 lbs/hr or 0.01 grains/scf. Compliance is achieved if either the mass limit or the concentration limit is met.

Each CTG is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the concentration is expected to be 0.0033 gr/scf.

Combustion Particulate (gr/scf) = (PM_{10}, lb/hr / Stack Exhaust Flow, scf) * 7000 gr/lb

PM_{10} = 9.5 lb/hr (4.5 lb/hr per turbine + 5.0 lb/hr per duct burner)

Stack exhaust flow = 20.3 E+06 scf/hr (see Rule 409 analysis, above)

Combustion Particulate = (9.5 / 20.3 E+06) * 7000 = 0.0033 gr/scf < 0.01 gr/scf limit

Rule 1134 – Emissions of NOx from Stationary Gas Turbines
This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

Rule 1135 – Emissions of NOx from Electric Power Generating Systems
This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

REGULATION XIII—NEW SOURCE REVIEW (NSR)
The SCAQMD new source review rules are based on both the National Ambient Air Quality Standards (NAAQS) and the California Ambient Air Quality Standards (CAAQS). The NAAQS referenced here are the primary NAAQS, which are the levels of air quality necessary, with an adequate margin of safety, to protect the public health.

- ***Rule 1303(a)(1)—BACT/LAER (PM_{10}, SOx, VOC, CO)***
- ***Rule 2005(c)(1)(A)—BACT/LAER (NOx)***

  Rule 1303(a)(1) requires Best Available Control Technology (BACT) for a new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia, with the SCAQMD interpreting the emission increase to be 1 lb/day or greater. BACT is based on the increase of uncontrolled emissions. Table 15 shows that the emissions for NOx, CO, VOC, $PM_{10}/PM_{2.5}$, and SOx will increase by at least 1 lb/day. (In Table 15, the emissions increase shown for NOx, CO, and VOC are based on controlled emissions to maintain consistency with the rest of the emissions calculations, but the controlled emissions increase is at least equal to the uncontrolled emissions increase.) Table 24 shows the ammonia emissions will increase by at least 1 lb/day.

  The SCAQMD is not in attainment for PM_{10} (California 24-hr and annual standards) and ozone, but is in attainment for PM_{10} (national 24-hr standard), CO, NOx, and SOx. Since NOx, SOx, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well. Specifically, NOx and VOC are precursors to ozone, PM_{10}, and $PM_{2.5}$ and SOx is a precursor to PM_{10} and $PM_{2.5}$. Thus, this rule requires BACT for NOx (non-RECLAIM), PM_{10}, SOx, and VOC. Moreover, the SCAQMD has determined that BACT is required for CO. Rule 2005(c)(1)(B) requires BACT for NOx for RECLAIM facilities. Consequently, BACT for NOx, PM_{10}, SOx, VOC, and CO are applicable to all permit units in this project, except for the oil water separator for which VOC emissions are less than 1 lb/day.

  Rule 1303(a)(2) provides that BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate (LAER) as defined in the federal Clean Air Act Section 171(3). A facility is a major polluting facility (same as major stationary source) if it emits, or has the potential to emit, a criteria air pollutant at a level that equals or exceeds the following emission thresholds: (1) VOC, 10 tpy; (2) NOx, 10 tpy; (3) SOx, 100 tpy; (4) CO, 50 tpy; and (5) PM_{10}, 70 tpy. If a threshold for any one criteria pollutant is equaled or exceeded, the facility is a major polluting facility, and will be subject to LAER for all pollutants subject to NSR. The RBGS is a major polluting facility because Table 10 indicates the PTEs for VOC (311.8 tpy), NOx (632.3 tpy), CO (70,693.4 tpy), and PM_{10} (430.9 tpy) exceed the applicable threshold.

Rule 1302(h) defines BACT as "the most stringent emission limitation or control technique which:

(1) has been achieved in practice [AIP] for such category or class of source; or

(2) is contained in any state implementation plan (SIP) approved by the US EPA approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or

(3) is any other emission limitation or control technique, found by the Executive officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board."

The first two requirements in the BACT definition above are required by federal law as LAER for major sources. The third part of the definition is unique to AQMD and some other areas in California, and allows for more stringent controls than LAER. For major polluting facilities, LAER is determined on a permit-by-permit basis.

The BACT/LAER requirements are analyzed below for the (1) gas turbines, (2) SCRs/CO oxidation catalysts, and (3) ammonia storage tank.

1. <u>A/N 545068, 545069, 545070—Combustion Gas Turbines Nos. 03-A, 03-B, 03-C</u>
2. <u>A/N 545066, 545067, 545071—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 03-A, 03-B, 03-C</u>

   The following sets forth the New Source Review BACT/LAER analysis for VOC, SO_2, and NH_3 which are not PSD pollutants for the proposed facility. As required by PSD, top-down BACT analyses are performed under Rule 1703(a)(2) below for the two pollutants subject to PSD review, NOx and PM_{10}. Although not subject to PSD review, a top-down BACT analysis is included for CO under Rule 1703(a)(2) for completeness.

   - <u>BACT/LAER for VOC Emissions</u>

     VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. Effective combustor design and post-combustion control using an oxidation catalyst are two technologies for controlling VOC emissions from a combustion turbine.

Combustor design--The formation of VOCs is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Good combustor design (such as dry low NOx combustors) and best operating practices will minimize the formation of VOC while reducing the combustion temperature and NOx emissions. (Dry low NOx combustors and NOx control are discussed below in greater detail under the top-down BACT analysis for NOx.)

Oxidation catalyst—As discussed in the top-down BACT analysis for CO, an oxidation catalyst is typically a precious metal catalyst bed located in the HRSG. In addition to controlling CO by enhancing the oxidation of CO to CO_2, the catalyst enhances the oxidation of VOC to CO_2 without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

Based on combined cycle facilities recently permitted by the SCAQMD, including (1) LA City, DWP Scattergood Generating Station (2013), (2) Pasadena City, Dept. of Water & Power (2013), and (3) El Segundo Power (2011), the BACT/LAER limit for VOC is 2 ppm at 15% O2 (1-hr averaging), without or with duct burner. This limit is consistent with the most stringent level found among recent BACT determination for combined cycle natural gas fired combustion turbines.

The proposed/guaranteed levels provided by the applicant is 1 ppm (1-hr averaging) without duct burners and 1 ppm (3-hr averaging) with duct burners based on a top-down BACT analysis including non-SCAQMD and SCAQMD combined-cycle turbine projects. The 1 ppmvd at 15% O_2 BACT levels is based on non-SCAQMD projects for which the VOC test method is **not** recognized by the SCAQMD. The proposed CTGs will be unable to meet a 1 ppmvd limit using the SCAQMD-approved test method. The BACT/LAER limit for VOC remains 2 ppm at 15% O2 (1-hr averaging), without or with duct burner. AES has accepted the SCAQMD's determination.

The applicant has proposed to install dry low NOx combustors and an oxidation catalyst to meet VOC BACT of 2 ppm at 15% O2 (1-hr averaging), without or with duct burner.

- BACT/LAER for SO_2 Emissions
  Emissions of SOx are dependent on the sulfur content in the fuel rather than any combustion variables. During the combustion process, almost all of the sulfur in the fuel is oxidized to SO_2.

  Natural-gas-fired turbines in California are typically required to combust only California Public Utilities Commission (CPUC) pipeline-quality natural gas with a sulfur content of less than 1 grain of sulfur per 100 scf. The RBEP would be supplied with natural gas from the Southern California Gas pipeline, which is limited by Tariff Rule No. 30 to a maximum total fuel sulfur content of less than 0.75 grain of sulfur per 100 scf. Therefore, the use of pipeline-quality natural gas with low sulfur content is BACT for SO_2.

- BACT/LAER for Ammonia Emissions
  A very small amount of ammonia used in the SCR systems to control NOx from the turbine exhaust stream is not consumed by the reaction in the SCR systems. The applicant is proposing a BACT limit of 5 ppm at 15% O_2 (1-hr averaging).

  The CARB "Guidance for Power Plant Siting and Best Available Control Technology," dated September 1999, recommends that BACT levels for ammonia for gas turbines be set at not more than 5 ppmvd at 15% O_2. The SCAQMD BACT for non-major sources for gas turbines rated at 50 MW or higher is 5.0 ppmvd at 15% O_2, and the BACT/LAER for major sources is the same limit with the additional requirement of 1-hr averaging. Therefore, the proposed limit of 5 ppm at 15% O_2 (1-hr averaging) meets BACT/LAER.

BACT/LAER vs. Warranty Levels
Based on the above BACT/LAER analysis for VOC, SO_2, and NH_3, and the PSD top-down BACT analysis for NOx, PM_{10}, and CO performed under Rule 1703(a)(2), the SCAQMD has determined that BACT/LAER emission limits for combined cycle facilities are as set forth in the table below. The table below presents the BACT/LAER guidelines, the limits proposed in the AFC, and the guarantees for NOx, CO, and VOC provided by Paul Eberle, Vogt Power International, in a letter dated 11/13/12.

Table 27 - Combined Cycle Gas Turbine BACT/LAER Requirements, Proposed and Guaranteed Emissions Levels

	NOx	CO	VOC	PM_{10}/SOx	NH_3
Combined Cycle Gas Turbine BACT/LAER Limits	2.0 ppmvd at 15% O2, 1-hr average, without and with duct burner.	2.0 ppmvd at 15% O2, 1-hr average, without and with duct burner.	2.0 ppmvd at 15% O2, 1-hr average, without and with duct burner.	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O2, 1-hr average
Proposed Limits in AFC based on Top-Down BACT Analysis	2.0 ppmvd at 15% O2, 1-hr average	2.0 ppmvd at 15% O2, 1-hr average	Without duct burner 1.0 ppmvd at 15% O2, 1-hr average With duct burner 1.0 ppmvd at 15% O2, 3-hr average	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5 ppmvd at 15% O2
Vogt Power guarantees	2 ppmvd at 15% O2	2 ppmvd at 15% O2	1 ppmvd at 15% O2		

The proposed CTGs are expected to meet the SCAQMD BACT/LAER standards.

- NOx
  The guaranteed emission rate of 2 ppmvd is the same as the BACT/LAER limit of 2 ppmvd at 15% O_2 (1-hr averaging), without and with duct firing.

- CO
  The guaranteed emission rate of 2 ppmvd is the same as the BACT/LAER limit of 2 ppmvd at 15% O_2 (1-hr averaging), without and with duct firing.

- VOC
  The proposed/guaranteed emissions rate of 1 ppmvd is lower than the SCAQMD BACT/LAER limit of 2 ppmvd at 15% O_2 (1-hr averaging), without and with duct firing. As discussed above, the 1 ppmvd at 15% O_2 BACT levels is based on non-SCAQMD projects for which the VOC test method is **not** recognized by the SCAQMD. The proposed CTGs will be unable to meet a 1 ppmvd limit using the SCAQMD-approved test method. Thus the SCAQMD BACT/LAER limit for VOC remains 2 ppmvd at 15% O_2 (1-hr averaging), without and with duct firing. AES has accepted the SCAQMD's determination. The PDOC and Permits to Construct will be based on the 2 ppmvd.

- $PM_{10}/PM_{2.5}$
  BACT/LAER requires the use of use of PUC quality natural gas with sulfur content less than or equal to 1 grain/100 scf, but does not specify an emission limit. Mitsubishi Power Systems America provided a $PM_{10}/PM_{2.5}$ emission rate of 4 pounds per hour, including both non-condensable fractions determined using EPA Method 201 or 201A, and condensable fractions determined using EPA Method (dry). However, the guaranteed particulate matter emission rate specifically excluded any contribution from fuel-bound sulfur. Consequently, AES increased the MPSA $PM_{10}/PM_{2.5}$ guarantee by 0.5 pounds per hour to account for fuel bound sulfur based on an expected sulfur content of 0.18 grains of total sulfur per 100 cubic feet of natural gas and a 10 percent sulfur dioxide (SO_2) to sulfur trioxide conversion rate. The application is based on a turbine $PM_{10}/PM_{2.5}$ emission rate of 4.5 pounds per hour irrespective of load rate.

  The Vogt Power International letter indicates the duct burner is rated at 450 MMBtu/hr (LHV) (converts to 507 MMBtu/hr HHV) and guarantees a PM_{10} emission rate is 0.01 lbs/MMBtu (HHV). AES concluded the duct burner $PM_{10}/PM_{2.5}$ emission rate is 5.0 pounds per hour.

- NH_3
  The 5 ppmvd at 15% O_2 (1-hr averaging) is the BACT/LAER level, but a guarantee is not yet available.

Commissioning, Startups and Shutdowns
Condition no. A195.5, A195.6, and A195.7 provide that the BACT limits of 2.0 ppmvd NOx, 2.0 ppmvd CO, and 2.0 ppmvd ROG, respectively, shall not apply during commissioning, startup, and shutdown periods.

During commissioning, it is not technically feasible for the CTGs to meet BACT limits during the entire period because the dry low-NOx combustors may not be optimally tuned and the emissions are only partially abated because the CO and SCR catalysts are installed and tested in stages. The turbines, however, are typically operated at less than 100% load during commissioning. To limit commissioning emissions, condition no. E193.4 limits the commissioning period to 491 hours per turbine.

During startups, it is not technically feasible for the CTGs to meet BACT limits during the entire startup because the SCR and CO catalysts that are used to achieve the required emissions reductions are not fully effective when the surface of the catalysts are below the manufacturers' recommended operating range. Condition C1.5 sets forth limits for cold, warm, and hot startups. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of startups per day; and (5) duration of cold start, warm start, and hot start; and (6) NOx, CO, and VOC emission per cold start, warm start, and hot start.

During shutdowns, it is not technically feasible for the turbines to meet BACT limits during the entire shutdown because ammonia injection into the SCR reactor has ceased operation. The SCR and CO catalysts, however, are still above ambient temperatures and continue to operate for a portion of the shutdown. Condition C1.6 sets forth limits for shutdowns. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdown; and (3) NOx, CO, and VOC emission per shutdown.

3. A/N 545072--Ammonia Storage Tank
   BACT for an ammonia storage tank requires the use of a pressure vessel for storage and a vapor return line for transfer, which are required by conditions C157.1 and E144.1, respectively. The tank will be a pressure vessel with a pressure relief valve set at 50 psig to control breathing losses. The filling losses will be controlled by a vapor return line to the delivery vehicle.

- ***Rule 1303(b)(1)—Modeling***
- ***Rule 2005(c)(1)(B)--Modeling***

Rule 1303(b)(1) requires air dispersion modeling to substantiate that a new or modified source which results in a net emission increase of any nonattainment air contaminant at a facility will not cause a violation, or make significantly worse an existing violation according to Table A-2 of the rule, of any state or national ambient air quality standards at any receptor location in the District, unless exempt from modeling requirements by Rule 1304. Rule 1303 requires modeling for NO_2 (non-RECLAIM), CO, PM_{10}, and SO_2. Rule 2005(c)(1)(B) requires modeling for NO_2 for RECLAIM facilities. (The standards in Table A-2, as amended December 6, 2002, are outdated. The modeling analyses below are based on current ambient air quality standards.)

Compliance determination is different for attainment and nonattainment pollutants. For the attainment pollutants, NO_2, CO, SO_2, PM_{10} (federal 24-hour standard), it should be demonstrated through modeling that the project impact plus the background concentration would not exceed the most stringent air quality standard. For non-attainment pollutants, such as PM_{10} (state 24-hour and annual standards), it should be demonstrated through modeling that the project impacts will not cause an exceedance of the SCAQMD's CEQA significant change thresholds in air quality concentration.

Rule 1304(a) provides an exemption from the modeling requirements of Rule 1303(b)(1) and the offset requirement of Rule 1303(b)(2) for:

(2) Electric Utility Steam Boiler Replacement
The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basin wide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset.

AES proposes to replace existing Utility Boiler No. 6 (175 MW), No. 7 (480 MW) and No. 8 (480 MW) with RBEP, which consists of a 3-on-1 combined-cycle gas turbine power block, rated at 546.4 MW gross. To offset the 546.4 MW for the RBEP, 480 MW will come from the shutdown of Boiler No. 7 (480 MW) and 66.4 MW is coming from the shutdown of Boilers Nos. 6 and 8 (655 MW combined). The surplus 588.6 MW from the shutdown of Boilers Nos. 6 and 8 will be used to offset the repowering projects at AES Huntington Beach and AES Alamitos.

Although the RBEP is exempt from modeling requirements, the applicant conservatively has provided the modeling required to demonstrate compliance with Rule 1303 (CO, PM_{10}, SO_2), Rule 2005 (NO_2), Rule 1401 (Health Risk Assessment for toxics), and Rule 1703 PSD (NO_2, PM_{10}). Planning, Rule Development & Area Sources (PRA) staff has provided extensive review and comments throughout the

PDOC development process, starting with the proposed dispersion modeling protocol submitted in July 2012. The modeling review memo, dated 12/11/13, from Elaine Chang, DEO PRA, to Sr. Engineering Manager Andrew Lee provided comments on the modeling, augmented by an e-mail dated 12/24/13 regarding the Rule 1401 results. As PRA staff reviewed the applicant's dispersion modeling by reproducing the modeling analysis, the approval memo was based on maximum modeled concentrations derived by PRA staff. <u>These maximum modeled concentrations from PRA are reflected in the modeling results tables for Rules 1303, 1703, 1401, and 2005, below</u>.

The applicant utilized AERMOD (version 12345) for the air dispersion modeling, which is the current EPA approved model and requires hourly meteorological data. The meteorological data from the SCAQMD's LAX meteorological station was used, which is appropriate for the project. The monitoring data from SRA 3, Southwest Coastal LA County (No. 820) monitoring station for the three year period, 2008 to 2010, were used to determine the background concentrations.

The base modeling receptor grid for the AERMOD modeling consists of receptors that are placed at the ambient air boundary and Cartesian-grid receptors that are placed beyond the project's site boundary at spacing that increases with distance from the origin. Property boundary receptors were placed at 30-meter intervals. Beyond the project's property boundary, receptor spacing was as follows:

- 50-meter spacing from property boundary to 500 meters from the origin
- 100-meter spacing from beyond 500 meters to 3 km from the origin
- 500-meter spacing from beyond 3 km to 10 km from the origin
- 1,000-meter spacing from beyond 10 km to 25 km from the origin
- 5,000-meter spacing from beyond 25 km to 50 km from the origin

- <u>Start Ups/Shutdowns and Normal Operation</u>
  A screening level dispersion modeling analysis was performed for three temperature conditions (33, 63.3, and 106 deg F) and five different load scenarios 70%, 80%, 90%, 100% without duct firing, and 100% with duct firing) for a total of 15 different scenarios (cases) to determine the worst case impacts. These are the same 15 cases as provided in Table 12—Operating Scenarios, above. (The results are presented in Table 5.1C.7a—"Operational Modeling Results Summary" in Appendix 5.1C—"Dispersion Modeling and Climate Information" of the AFC.) Once the worst case impacts were determined per pollutant, the stack parameters for that case in combination with the emission rates as shown in the table below were used in the refined model.

Table 28 - Modeled Emission Rates - Start Up/Shutdowns and Normal Operation[1]

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions Per Turbine, lbs/hr
1-hour	NOx: All three turbines in start-up mode, 106 °F ambient temperature.	NOx	25.4
	CO: All three turbines in startup mode, 106 °F ambient temperature.	CO	114
	SOx: All three turbines 100% load with duct firing, 33 °F ambient temperature.	SOx	2.63
3-hour	SOx: All three turbines continuous 100% load operation with duct firing, 63.3 °F ambient temperature.	SOx	2.51
8-hour	CO: All three turbines complete one cold start, two warm starts, 3 shutdowns, and remainder of period at 70% load, 106 °F ambient temperature.	CO	45.4
24-hour	PM_{10}: All three turbines continuous 70% load operation without duct firing, 106 °F ambient temperature.	PM_{10}	4.5
	SOx: All three turbines continuous 70% load operation without duct firing, 63.3 °F ambient temperature.	SOx	1.35
Annual	NOx, PM_{10}: All three turbines operate at 70% load for 6,370 hours (5,900 without duct firing, 470 with duct firing), 24 cold starts, 150 warm starts, 450 hot starts, and 624 shutdowns, without duct firing, 63.3 °F ambient temperature. Total hours, including startups and shutdowns, are 6835 hours (condition A63.1).	NOx	9.23
		PM_{10}	3.78

1 Operating loads, ambient temperatures, and emission rates from Table 5.1-24—"Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts" on pg. 5.1-24 of AFC. Scenario descriptions from (1) "Operation Impacts Analysis" discussion on pg. 5.1-23, and (2) e-mail, dated 8/5/13, from CH2M Hill clarifying whether the dispersion modeling for each averaging time was based three turbines or one turbine operating (item 1).

Table 29 - Modeled Stack Parameters - Start Up/Shutdowns and Normal Operation[1]

Pollutants	Averaging Periods	Stack Diameter, m	Stack Ht, m	Exhaust Temp, °F (°K)	Exhaust velocity, m/s	Operating Case
NOx	1-hour[2]	5.49	42.7	374 (463)	49.5	15
	Annual	5.49	42.7	373 (462)	52.4	10
CO	1-hour	5.49	42.7	374 (463)	49.5	15
	8-hour	5.49	42.7	374 (463)	49.5	15
SO_2	1-hour	5.49	42.7	398 (476)	79.0	1
	3-hour	5.49	42.7	396 (475)	74.8	6
	24-hour	5.49	42.7	373 (462)	52.4	10

PM_{10}	24-hour	5.49	42.7	374 (463)	49.5	15
	Annual	5.49	42.7	373 (462)	52.4	10

1 Stack diameters and stack heights from Table 5.1C.4—"Operational Modeling Parameters - Stack Parameters" found in Appendix 5.1C—"Dispersion Modeling and Climate Information" of AFC. Operating scenario/case numbers, exhaust temperatures and velocities from Table 5.1-24 on pg. 5.1-24 of AFC. The operating scenario parameters for the four operating cases listed in the table above are from Table 5.1C.7a—Operational Modeling Results Summary found in Appendix 5.1C of AFC: (1) Case 15--106 °F, 70% load; (2) Case 10--63.3 °F, 70% load; (3) Case 1--33 °F, 100% with duct burner; and (4) Case 6--63.3 °F, 100% with duct burner firing. Case nos. and parameters are the same as in Table 12, above.

2 The one-hour NOx is based on stack parameters that correspond to normal operations because the duration required for startup of the turbine only is 10 minutes for all startup scenarios.

The applicant provided dispersion modeling for maximum RBEP operational impacts. The highest modeled concentrations, as provided in the PRA staff modeling review memo, are used to demonstrate compliance with the ambient air quality standards in the table below.

Table 30 - Model Results – Start up/Shutdown and Normal Operation for RBEP Operation

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m³)	Background Concentration (µg/m³)²	Total Predicted Concentration (µg/m³)	State Standard CAAQS (µg/m³)	Federal Standard, Primary NAAQS (µg/m³)	Significant Change in Air Quality Concentration (µg/m³)	Compliance?
NO_2	1-hour	31.91	169	200.91	339	--		Yes
	Federal 1-hour	See Rule 1703 PSD analysis below for cumulative impact analysis results.			--	188		N/A
	Annual	0.40	29.9	30.3	57	100		Yes
SO_2	1-hour	4.13	67.8	71.93	655	--		Yes
	Federal 1-hour	4.13	37.5	41.63	--	196		Yes
	3-hour	2.74	38.7	41.44	--	1,300		Yes
	24-hour	0.53	15.7	16.23	105	365		Yes
CO	1-hour	179.05	4,581	4760	23,000	40,000		Yes
	8-hour	38.36	2,863	2,901	10,000	10,000		Yes
PM_{10}	24-hour	1.75	52	53.75		150		Yes
	24-hour	1.75	52		50		2.5	Yes
	Annual	0.22	25.6		20		1	Yes

For NO_2, the above table demonstrates that the peak 1-hour and annual NO_2 impacts plus the worst-case background do not exceed the most stringent air quality standards. As for the federal 1-hour standard, RBEP is PSD for NOx as discussed under the *Regulation XVII—Prevention of Significant Deterioration* analysis below. If the peak 1-hour NO_2 impacts of 31.91 µg/m³ had not exceeded the Class II significance impact level (SIL) of 7.52 µg/m³, it would be appropriate to compare the peak 1-hour NO_2 impact from RBEP plus the worst-case background with the federal 1-hour NO_2 standard of 188 µg/m³. Since the SIL was exceeded, the applicant was required to assess the cumulative impacts of the RBEP and nearby sources for all receptors where RBEP impacts alone exceeded the 1-hour NO_2 SIL. The maximum predicted cumulative 1-hour NO2 impacts from RBEP operation plus cumulative projects plus background were then compared with the federal 1-hour NO_2 standard as part of the PSD analysis. These results are presented in Table 42—RBEP and Nearby Sources Predicted 1-Hour NO_2 Impacts Compared to the NAAQS. (The US EPA-approved NO_2 to NOx conversion ratios of 0.80 and 0.75 are assumed for evaluating 1-hour and annual NO_2 impacts from the project, respectively.)

For SO_2, the peak 1-hour, 3-hour, and 24-hour SO_2 impacts plus the worst-case background do not exceed the most stringent air quality standards. Additionally, on 6/2/2010, the US EPA established a new 1-hour SO_2 standard. The applicant used the maximum AERMOD predicted 1-hour SO_2 concentration for the total project and added it to the 99th percentile background concentration. The peak 1-hour SO_2 impact plus the worst-case background is less than the federal 1-hour SO_2 standard.

For CO, the peak 1-hour and 8-hour CO impacts plus the worst-case background concentrations do not exceed the most stringent air quality standards.

For PM_{10}, the total project's peak 24-hour PM_{10} impact plus the worst-case background is less than the federal 24-hour standard. The background PM_{10} air quality in the impact area, however, exceeds the state 24-hour and annual PM_{10} standards. Accordingly, to determine compliance with the state standards, project increments are compared to the SCAQMD's CEQA significant change thresholds. The peak 24-hour and annual PM_{10} impacts for the total project are less than the 24-hour and the annual significant change thresholds, respectively.

- Commissioning
  The potential impacts on ambient air quality associated with the RBEP commissioning activities were assessed based on engineering estimates of schedule and emissions. It was assumed that the maximum impact would occur if all three turbines were simultaneously undergoing commissioning activities with the highest unabated emissions (for example, initial full-speed, no-load CTG testing, steam blows, HRSG, and steam safety valve settings).

  The analysis includes NOx and CO only. Since the duct burners are not expected to be fired during the initial unabated commissioning activities, the maximum impacts for SO_2 and PM_{10} are expected to be equal to or lower than normal operating rates with duct firing. The analysis excluded a comparison to the annual averaging period standards or thresholds because commissioning will only occur once during the project lifetime, and it is expected to be completed within 180 calendar days. The analysis also excluded a comparison to the federal 1-hour NO_2 and SO_2 standards because the maximum hourly unabated emission rates that result in the highest predicted concentrations are only expected to occur once during the life of the project, and that one time would be less than 40 hours per turbine. The 1-hour standards are also based on a 98th and 99th percentile statistical standard. Therefore, it is unlikely that simultaneous one-time unabated emissions for all three turbines would occur on the days with the highest background NO_2 and ozone concentrations.

The commissioning modeling was performed at four different turbine operating rates. The emissions rates and modeling parameters are presented in the table below.

Table 31 - Modeled Emission Rates, Commissioning[1]

Scenarios	No. of Turbines/ Modeling Load	Exit Velocity (m/s)	Exhaust Temperature °F (°K)	Emissions Rates per Turbine (lb/hr) 1-Hr NOx	1-Hr CO	8-Hr CO
CTG testing (full speed no load)	Three/5%	10.06	499.8	48.53	1,709	1,709
Steam Blows	Three/50%	9.90	465.9	109.8	3,169	3,169
Set unit HRSG and steam safety valves	Three/100%	22.73	471.7	41.95	28.4	28.4
Restart CTGs and run HRSG in bypass mode. STG bypass valve tuning. HRSG blow down & drum tuning.	Three/40%	9.95	473.2	25.97	1,373	1,373

1 Emissions rates, exhaust temperatures, and velocities from Table 5.1-23—"RBEP Commissioning Dispersion Modeling Scenarios" on pg. 5.1-23 of AFC.

The applicant has provided modeling for the most conservative case of three turbines simultaneously undergoing the same commissioning activity. The maximum NO_2 and CO impacts will occur when all three turbines are in the steam blows at 50% load scenario, which is the most conservative case. The steam blows of the first CTG are expected to last up to 40 hours at 50 percent load. The steam blows on the remaining two CTGs will only last up to 20 hours each at 50 percent load. In actuality, although two turbines may be commissioned at one time, steam blows can only be performed on one turbine at a time because steam is blown through the entire system.

The table below shows the peak 1-hour NO_2 project impact during commissioning, plus the background concentrations, do not exceed the state 1-hour NO_2 standard. The peak 1-hour and 8-hour CO project impacts during commissioning, plus the worst-case background concentrations, do not exceed the most stringent air quality standards. (The peak impacts are from the PRA staff modeling review memo.)

Table 32 - Model Results, Commissioning

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)[1]	Background Concentration ($\mu g/m^3$)[2]	Total Concentration ($\mu g/m^3$)	State Standard CAAQS ($\mu g/m^3$)	Federal Standard, Primary NAAQS ($\mu g/m^3$)	Compliance?
NO_2	1-hour	168.48	169	337.48	339	--	Yes
CO	1-hour	6084.98	4,581	10,666	23,000	40,000	Yes
	8-hour	3924.67	2,863	6,788	10,000	10,000	Yes

- ***Rule 1303(b)(2)--Offsets***
  - VOC, SOx, and PM_{10}

    Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant (PM_{10}, ROG, and SOx) from a new or modified source to be offset unless exempt from offset requirements pursuant to Rule 1304. Since CO is an attainment pollutant and not a precursor to any nonattainment pollutant, offset requirements are not applicable.

    "Source" is defined by Rule 1302(ao) to mean "any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility."

    Unless exempt, the amount of offsets required for each pollutant is determined using the 30-day average. The 30-day average is based on the higher of the emissions for a commissioning month or a normal operating month. The offset ratio for emission reduction credits (ERCs) is 1.2-to-1.

    As discussed above, Rule 1304(a)(2) provides an exemption from the offset requirements, in addition to the modeling requirements, for RBEP.

  - NOx

    See *Rule 2005(c)(2)* analysis below for NOx RTC requirements.

- ***Rule 1303(b)(3)-Sensitive Zone Requirements***
- ***Rule 2005(e)-Trading Zone Restrictions***

  Both rules provide that credits shall be obtained from the appropriate trading zone. Rule 1303(b)(3) is not applicable because offsets will not be required to be purchased. Rule 2005(e) is applicable for any RTC purchases.

- ***Rule 1303(b)(4)-Facility Compliance***

  RBEP will comply with all applicable rules and regulations of the District, as required by this rule.

- ***Rule 1303(b)(5)-Major Polluting Facilities***
- ***Rule 2005(g)—Additional Federal Requirements for Major Stationary Sources***

  Any major modification at an existing major polluting facility shall comply with the following provisions. RBGS is an existing major polluting facility as defined by Rule 1302(s), and its replacement by RBEP is a major modification under Rule 1302(r).

- ***Rule 1303(b)(5)(A) – Alternative Analysis***
- ***Rule 2005(g)(2)—Alternative Analysis***
- ***Rule 1303(b)(5)(D) – Compliance through CEQA***
- ***Rule 2005(g)(3)—Compliance through CEQA***

  Rule 1303(b)(5)(A) requires an analysis of alternative sites, sizes, production processes, and environmental control techniques and a demonstration that the benefits of the proposed project outweigh the environmental and social costs associated with that project. Rule 2005(g)(2) requires an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, or modification.

  Rule 1303(b)(5)(D) specifies the requirements of subparagraph (b)(5)(A) may be met through compliance with CEQA. Rule 2005(g)(3) specifies the requirements of paragraph (g)(2) may be met through CEQA analysis.

  The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. The CEC's 12-month permitting process is a certified regulatory program under CEQA and includes various opportunities for public and inter-agency participation. AES submitted an application for certification (12-AFC-03) to the CEC on 11/20/12 seeking certification for RBEP. Section 6 of the AFC presents a review of alternatives to the RBEP technology. The assessment considered alternative technologies that could have reduced environmental impacts, while satisfying the project objectives. Alternative generating technologies, including geothermal plants, hydroelectric plants, biomass-fired plants, solar plants, and wind generation plants, were considered but rejected due to the inability of these technologies to provide generating capacity for local reliability needs, meet peak energy demands, and provide controllable and flexible generation with minimum environmental effects.

- ***Rule 1303(b)(5)(B) – Statewide Compliance***
- ***Rule 2005(g)(1) – Statewide Compliance***

  Rule 1303(b)(5)(B) requires a demonstration that all major stationary sources are owned or operated by such person in the state are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Rule 2005(g)(1) requires the applicant to certify that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards. Stephen O'Kane, Manager, AES Redondo Beach, LLC, provided a letter, dated 12/13/13, certifying that RBGS and all other facilities that are owned or operated by AES within California with all applicable emissions limitations, standards, rules, regulations and laws promulgated pursuant to the Clean Air Act.

- ***Rule 1303(b)(5)(C) –Protection of Visibility***
- ***Rule 2005(g)(4)—Protection of Visibility***

Rule 1303(b)(5)(C) requires a modeling analysis for plume visibility if the net emission increases from a new or modified sources exceed 15 tpy of PM_{10} or 40 tpy of NOx; and the location of the source, relative to the closest boundary of a specified Federal Class I area, is within the distance specified in Table C-1 of the rule. Rule 2005(g)(4) imposes the same requirements for NOx, with the Federal Class I areas and distances provided in Table 4-1 of the rule (same as Table C-1).

As shown in Table 36—PSD Applicability, the net emissions increase (RBEP PTE – RBGS actual) exceeds 15 tpy PM_{10} and 40 tpy NOx. The applicant has identified the San Gabriel Wilderness, approximately 53 km from the RBEP site, as the nearest Class I area. Tables C-1 and 4-1 requires a visibility analysis if the RBEP site is within 29 km of the closest boundary of San Gabriel Wilderness. Since the RBEP is not within 29 km, a visibility analysis is not required.

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

The relevant sections are presented below, followed by the rule analysis.

(a) The purpose of this rule is to require Electrical Generating Facilities (EGFs) which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay fees for up to the full amount of offsets provided by the SCAQMD.... Notwithstanding Rule 1301(c)(1), this rule applies to all permits issued to EGFs electing to use Rule 1304(a)(2) and receiving the applicable permit to construct on or after September 6, 2013.

(c) Requirements

(1) Any EGF operator electing to use the offset exemptions provided by Rule 1304(a)(2) shall pay a fee, the Offset Fee (Fi), calculated pursuant to paragraph (c)(2), for each pound per day of each pollutant (i), for which the SCAQMD provides offsets. This fee may be paid on an annual basis or as a single payment or a combination of both at the election of the applicant.

(2) The Offset Fee (Fi), for a specific pollutant (i), shall be calculated by multiplying the applicable pollutant specific Annual Offset Fee Rate (Ri) or Single Payment Offset Fee Rate (Li) and Offset Factor in Table A1 or A2, as applicable, by the fraction of the potential to emit level(s) of the new replacement unit(s). This fraction is calculated as the product of the potential to emit of the new replacement unit (PTErepi) multiplied by the new replacement to existing unit generation annual capacity ratio. This annual capacity ratio which is defined as the maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s) (Crep) minus the most recent twenty-four (24) months average of the megawatt hour

(MWh) generation (megawatt utilization) of the unit(s) to be replaced (C2YRAvgExisting) divided by the maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s) (Crep).

Analysis:

In an e-mail, dated 10/14/13, AES has preliminarily selected the annual payment option. As such, the owner/operator is required to remit the first year annual offset fee payment prior to the issuance of the permits to construct. Therefore, the calculation of the annual fee for PM_{10}, SOx, and VOC is not required and not provided at this time. The applicant provided the criteria to determine the 30-day average emissions for these pollutants, however, with the recognition that these 30-day average emissions will factor into the fee calculation.

The SCAQMD has provided a Rule 1304.1 calculator, comprised of Excel worksheets, that is available on the SCAQMD website. The Rule 1304.1 calculator results are reproduced on the next page. The inputs for the calculator are discussed below.

a-Gross Rating of New Replacement Units (MW): 546.4 MW

Basis: [(131.9 MW gross/ CTG) * (3 CTGs) + 150.7 MW gross/steam turbine] = 546.4 MW

b-Maximum Fraction of Time Allowed to Operate (%): 78%

Basis:
c-Max Allowable Operating Hours Annually (hr/yr) = 6835 hr/yr

Hours in a Year (hr/yr) = 8760 hr/yr

Fraction of Time Allowed to Operate = 6835 hr/yr ÷ 8760 hr/yr = 78%

Note: For the purpose of this rule, startup and shutdown hours are included.

e-Average Last 2 years of Existing Unit(s) Actual Generation (MWh/yr): Not Available

Basis:
Rule 1304.1(c) defines $C_{2YRAvgExisting}$ to mean "the average annual megawatt-hour (MWh) generation of the existing unit(s) to be replaced using the last twenty-four (24) month period immediately prior to issuance of the permit to construct." To offset the 546.4 MW for the RBEP, 480 MW will come from the shutdown of Boiler No. 7 (480 MW) and 66.4 MW is coming from the shutdown of Boilers Nos. 6 and 8 (655 MW combined). Therefore, the last two years of existing unit(s) actual generation (all of Boiler No. 7, and a portion of Boilers No. 6 and 8) will need to be provided once the

timing of the issuance of the permits to construct is established. The RBGS's megawatt-hours are reported to the EPA through the EPA's Acid Rain program and can be downloaded for the appropriate 24-month period.

$PTEr_{PM10}$: 427.8 lb/day

Basis:
Rule 1304(c)(2) defines PTE_{repi} as "the permitted potential to emit of new replacement unit(s) for pollutant I, in pounds per day. (Maximum permitted monthly emissions ÷ 30 days)." Per turbine, this is the same as the "30-Day Average for New Source Review, lb/day" from Table 20, above. [Calculated as (142.59 lb/day-turbine) * 3 turbines = 427.8 lb/day]

$PTEr_{SOx}$: 158.3 lb/day

Basis:
See Table 20 per turbine, above. [Calculated as (52.77 lb/day-turbine) * 3 turbines = 158.3 lb/day]

$PTEr_{VOC}$: 1412.07 lb/day

Basis:
See Table 20 per turbine), above. [Calculated as (470.69 lb/day-turbine) * 3 turbines = 1412.07 lb/day]

$PTEr_{NOx}$: Not applicable because this is a RECLAIM facility.

Once the timing of the issuance of the permits to construct is established and the "e-Average Last 2 years of Existing Unit(s) Actual Generation (MWh/yr)" for the appropriate 24-month period can be provided by the applicant, the Rule 1304.1 calculator table on the next page will be completed to estimate the annual fee for PM_{10}, SOx, and VOC.

Table 33 - Rule 1304.1 Emissions Offset Fee Calculator – 100 MW Or More Cumulatively (Effective 9/6/2013)

		Enter Values In These Shaded Cells Only							
Input Cumulative Project Profile Values:									
a-Gross Rating of New Replacement Unit(s) (MW)					546.4				
b-Maximum Fraction of Time Allowed to Operate (%)					78				
Hours in a Year (hr/yr)					8,760				
c-Max Allowable Operating Hours Annually (hr/yr)					6,835				
d-Max Allowed Generation New Replacement Unit(s) Annually (MWhr/yr)					3,731,910	= C_{rep}*			
e- Average Last 2 Years of Existing Unit(s) Actual Generation (MWh/yr)					Not Available	= $C_{2YRAvgExisting}$			
ANNUAL FEE PAYMENT		**(> 100 MW Cumulatively):**							
i	$PTEr_{PM10}$	$R_{PM10\ A1}$	$R_{PM10\ A2}$	$R_{PM10\ blended}$	OF_{PM10}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{PM10}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
PM10	427.80	997	3,986	3,439	1.00	3,731,910	Not Available	1.0	Not Available
	$PTEr_{SOx}$	$R_{SOx\ A1}$	$R_{SOx\ A2}$	$R_{SOx\ blended}$	OF_{SOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{SOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
SOx	158.30	793	3,170	2,735	1.00	3,731,910	Not Available	1.0	Not Available
	$PTEr_{VOC}$	$R_{VOC\ A1}$	$R_{VOC\ A2}$	$R_{VOC\ blended}$	OF_{VOC}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{VOC}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
VOC	1,412.07	47	185	160	1.20	3,731,910	Not Available	1.0	Not Available
	$PTEr_{NOx}$	$R_{NOx\ A1}$	$R_{NOx\ A2}$	$R_{NOx\ blended}$	OF_{NOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{NOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
NOx**	Not Applicable	666	2,663	2,297	1.20	3,731,910	Not Applicable	1.0	Not Applicable
** Only applicable if project source is not in RECLAIM							**TOTAL ANNUAL FEE ($/yr)**		Not Available
* If C_{rep} is known it can be entered directly (in MWh)									

Rule 1313—Permits to Operate

Section (d) is applicable to the retirement plan.

(d) For a new source or modification which will be a replacement, in whole or part, for an existing source on the same or contiguous property, a maximum of 90 days may be allowed as a start-up period for simultaneous operation of the subject sources.

The schedule for the Redondo Beach Generating Station Boilers Nos. 6, 7, and 8 shutdown is July 1, 2018, with demolition to take place the first quarter of 2019. Condition no. F52.1 limits simultaneous operation to 90 days, and sets forth a number of requirements for the retirement plan and retirement of Boilers Nos. 6, 7, and 8. The condition includes requiring AES to provide a notarized statement by 12/31/18 that these boilers are permanently shut down.

Rule 1325—Federal PM2.5 New Source Review Program

The relevant sections are presented below, followed by the rule analysis.

(a) This rule applies to any new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility in and of itself; located in areas federally designated pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 81.305 as non-attainment for $PM_{2.5}$. With respect to major modifications, this rule applies on a pollutant-specific basis to those pollutants for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

(b) Definitions

For the purposes of this rule, the definitions in Title 40 CFR 51.165(a)(1), as it exists on (*date of adoption*) shall apply, unless the same term is defined below, then the defined term below shall apply:

(1) BASELINE ACTUAL EMISSIONS means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with the following:

(A) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Executive Officer shall allow the use of a different time period upon a determination that it is more representative of normal source operation….

(4) MAJOR MODIFICATION means:

(A) Any physical change in or change in the method of operation of a major polluting facility that would result in: a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major polluting facility.

(5) MAJOR POLLUTING FACILITY means, on a pollutant specific basis, any emissions source located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit, 100 tons or more per year of $PM_{2.5}$, or its precursors. A facility is considered to be a major polluting facility only for the specific pollutant(s) with a potential to emit of 100 tons or more per year.

(13) SIGNIFICANT means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:
Nitrogen oxides: 40 tons per year
Sulfur dioxide: 40 tons per year
$PM_{2.5}$: 10 tons per year

(c) Requirements

(1) The Executive Officer shall deny the Permit for a new major polluting facility; or major modification to a major polluting facility; or any modification to an existing facility that would constitute a major polluting facility in and of itself, unless each of the following requirements is met:

(A) LAER is employed for the new or relocated source or for the actual modification to an existing source; and

(B) Emission increases shall be offset at an offset ratio of 1.1:1 for $PM_{2.5}$ and the ratio required in Regulation XIII or Rule 2005 for NOx and SO_2 as applicable; and

(C) Certification is provided by the owner/operator that all major sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act; and

(D) An analysis is conducted of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstration made that the benefits of the proposed project outweigh the environmental and social costs associated with that project.

(h) Test Methods

For the purpose of this rule only, testing for point sources of $PM_{2.5}$ shall be in accordance with U.S. EPA Test Methods 201A and 202.

Analysis:

The applicability analysis is summarized in the table below.

Table 34 – Rule 1325 Applicability

	NOx	SO_2	$PM_{2.5}$
Redondo Beach Generating Station Potential to Emit, TPY (*Table 10*)	632.3	34.1	65.5
Major Source for Particular Pollutant?	Yes, PTE is greater than 100 tpy.	No, PTE is less than 100 tpy.	No, PTE is less than 100 tpy.
Redondo Beach Generating Station Actual Emissions (2011 & 2012 Avg) TPY (*Table 11*)	25.03	1.54	3.38
Redondo Beach Energy Project Potential to Emit, TPY (*Table 23*)	121.5	7.35	49.65
Net Emissions Increase (RBEP PTE – RBGS actual)	96.47	5.81	46.27
If RBGS is a major facility for particular pollutant, does the RBEP result in a net significant emissions increase?	Yes, net increase is greater than 40 tpy.		
If RBGS is not a major facility for particular pollutant, does the RBEP constitute a modification that would constitute a major polluting facility in and of itself?		No, net increase is less than 100 tpy.	No, net increase is less than 100 tpy.
Rule 1325 Applicable?	Yes	No	No

Rule 1325 is applicable to NOx. The RBGS is a major polluting facility for NOx because the PTE is greater than 100 tpy, and the RBEP constitutes a major modification because the net NOx increase is greater than 40 tpy. NOx meets the requirements of Rule 1325(c)(1)(A) – (D). For (c)(1)(A), the turbines meet LAER for NOx as discussed under the *Rule 1703(a)(2)—Top-Down BACT* analysis, below. For (c)(1)(B), the NOx emissions will be offset as discussed under the analysis for Rule 2005(c)(2)—Offsets, below. For (c)(1)(C), certification of statewide compliance is provided as discussed under Rule 2005(g)(1)—Statewide Compliance, below. For (c)(1)(D), the alternatives discussion was provided as discussed under the Rule 2005(g)(2)—Alternative Analysis, below.

Rule 1325 is not applicable to SO_2 and $PM_{2.5}$. The RBGS is not a major polluting facility for SO_2 and $PM_{2.5}$ because the PTEs for both are less than 100 tpy. The RBEP does not constitute a modification to an existing facility that would constitute a major polluting facility in and of itself, because the net increase for SO_2 and $PM_{2.5}$ are less than 100 tpy each. It is not necessary to include a condition to limit the potentials to emit of SO_2 and $PM_{2.5}$ emissions because the following conditions will limit potentials to emit for all pollutants. Condition A63.1 limits annual operations to 6835 hours in any calendar year (including startups and shutdowns). Moreover, condition C1.5 includes limits that will limit annual emissions for startups, and condition C1.6 includes limits that will limit annual emissions for shutdowns.

Source test condition D29.1 requires EPA Method 201A and 202 for $PM_{2.5}$ testing. These methods do not specify an averaging time. Consultation with the SCAQMD source testing department indicates the sampling time is required to be long enough to obtain a measureable amount of sample, with past tests performing at least 4 hours of sampling.

Rule 1401—New Source Review of Toxic Air Contaminants
Rule 2005(i) – RECLAIM Rule 1401 Compliance

Rule 1401 specifies limits for maximum individual cancer risk (MICR), and acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permits that emit toxic air contaminants. Rule 2005(j) requires compliance with Rule 1401 for RECLAIM facilities.

The applicant provided revised toxic air pollutant (TAC) and hazardous air pollutant (HAP) emissions rates for each turbine with duct burner in Response Letter No. 2, dated 3/15/13, item 3.b., Table 5.1B.5bR on pg. 4. The emissions rates were revised to be based on US EPA AP-42 emission factors, as required by the SCAQMD. The emissions calculations are summarized in Table 24--Toxic Air Contaminants/ Hazardous Air Pollutants per Turbine, above.

The maximum hourly impacts were predicted for the 106 degrees Fahrenheit (°F), 70 percent load case, which represents the turbine exhaust parameters associated with the maximum predicted 1-hour ground level impact in the air quality impact analysis (Case 15 in Table 12). The annual impacts were predicted for the 63.3 °F, 70 percent load case, which represents the average annual temperature and load scenario resulting in the maximum predicted annual ground level impact (Case 10 in Table 12).

The HRA modeling was conducted using the ARB *Hotspots Analysis Reporting Program* (HARP, Version 1.4f), along with the ARB HARP On-ramp program (Version 1.0). The SCAQMD HRA procedures require HARP to be used in Tier 4 risk assessments. The HARP On-ramp tool was used to import the American Meteorological Society/EPA Regulatory Model (AERMOD) air dispersion modeling results into the HARP Risk Module. The AERMOD dispersion model (Version 12345) was used to predict ground-level concentrations of air toxic emissions associated with RBEP. The AERMOD settings, source parameters, meteorological data, and source definition for the risk assessment were the same as the air quality impact analysis methodology performed for Rules 1303 and 1703.

In an e-mail dated 8/5/13, the applicant provided a summary of the health risk assessment results revised to reflect the AP-42 emission factors for both the individual turbines as required by Rule 1401 and for the project (three turbines) as required by CEQA. The table below demonstrates that each of the three turbines will be in compliance with the MICR limit of 1 in a million, the chronic and acute hazard index limits of 1.0, and the cancer burden limit of 0.5.

As discussed for the Rule 1303(b)(1) and Rule 2005(c)(1)(B) modeling analysis above, the modeling review memo, dated 12/11/13, from Elaine Chang, DEO PRA, to Sr. Engineering Manager Andrew Lee provided comments on the modeling, augmented by an e-mail dated 12/24/13 regarding the Rule

1401 results. As PRA staff reviewed the applicant's dispersion modeling by reproducing the modeling analysis, the approval memo was based on maximum modeled concentrations derived by PRA staff. These maximum modeled concentrations from PRA are reflected in the modeling results tables for Rules 1303, 1703, 1401, and 2005.

Table 35 – Rule 1401 Compliance Summary

Health Risk Index	Residential/ Sensitive Receptor Risk	Worker Receptor Risk	Rule 1401 Standard (no T-BACT)	Complies?
Turbine 03-A				
MICR	0.69 x 10^{-6}	0.13 x 10^{-6}	1 x 10^{-6}	**Yes**
HIC	0.00217	0.00218	1	**Yes**
HIA	0.0206	0.0206	1	**Yes**
Turbine 03-B				
MICR	0.66 x 10^{-6}	0.12 x 10^{-6}	1 x 10^{-6}	**Yes**
HIC	0.00206	0.00201	1	**Yes**
HIA	0.0144	0.0144	1	**Yes**
Turbine 03-C				
MICR	0.65 x 10^{-6}	0.11 x 10^{-6}	1 x 10^{-6}	**Yes**
HIC	0.00205	0.00196	1	**Yes**
HIA	0.0116	0.0116	1	**Yes**

REGULATION XVII – PREVENTION OF SIGNIFICANT DETERIORATION

The federal Prevention of Significant Deterioration (PSD) has been established to protect deterioration of air quality in those areas that already meet the primary NAAQS. This regulation sets forth preconstruction review requirements for stationary sources to ensure that air quality in clean air areas do not significantly deteriorate while maintaining a margin for future industrial growth. Specifically, the PSD program establishes allowable concentration increases for attainment pollutants due to new or modified emission sources that are classified as major stationary sources.

Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants. On 3/3/03, EPA rescinded its delegation of authority to the AQMD. On 7/25/07, the EPA and AQMD signed a new "Partial PSD Delegation Agreement." The agreement is intended to delegate the authority and responsibility to the District for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not set forth in AQMD Regulation XVII. The Partial Delegation agreement did not delegate authority and responsibility to AQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21.

Since this is a partial delegation the facilities in the South Coast Air Basin (SCAB) may either apply directly to EPA for the PSD permit in accordance with the current requirements of 40 CFR Part 52 Subpart 21, or apply to the SCAQMD in accordance with the current requirements of Regulation XVII. AES has opted to apply to the SCAQMD.

The SCAB has been in attainment for NO_2, SO_2, and CO emissions. In addition, effective 7/26/13, the SCAB has been redesignated to attainment for the 24-hour PM_{10} national ambient air quality standard. Therefore, this regulation applies to these emissions.

- ***RULES 1701, 1702, 1706--PSD APPLICABILITY***
  The relevant PSD applicability rule sections are presented below, followed by the applicability analysis.

  - ***Rule 1701(b)(2)*** provides:
    All of the requirements of this regulation apply, except as exempted in Rule 1704, to the following stationary sources:

    (A) A new source or modification at an existing source where the increase in potential to emit is at least 100 or 250 tons of attainment air contaminants per year, depending on the source category; or

    (B) A significant emission increase at an existing major stationary source; or

    (C) Any net emission increase at a major stationary source located within 10 km of a Class I area, if the emission increase would impact the Class I area by 1.0 $\mu g/m^3$, (24-hours average).

  - ***Rule 1702*** provides definitions.

    (m) "Major Stationary Source" means: "one of the following source categories: (1) Fossil fuel-fired steam electric plants of more than 250 million BTU/hr input…; which emits or has the potential to emit 100 tons per year or more of any contaminant regulated by the Act; or (2) an unlisted stationary source that emits or has the potential to emit 250 tons per year or more of any pollutant regulated by the Act; or (3) a physical change in a stationary source not otherwise qualifying under paragraph (1) or (2) if a modification would constitute a major stationary source by itself.

    (s) Significant Emission Increase means any attainment air contaminant for which the net cumulative emission increase of that air contaminant from a major stationary source is greater than the amount specified as follows:

Contaminant	Emissions Rate (tpy)
Carbon Monoxide	100
Sulfur Dioxide	40
Nitrogen Oxides	40
PM_{10}	15

- ***Rule 1706*** shall be used as the basis for calculating applicability to Regulation XVII as delineated in Rule 1703(a). **Rule 1706(c)** provides the emissions calculation methodology for determining a net emission increase.

(1)(A) The emissions for new permit units shall be calculated as the potentials to emit.

(1)(B) The emissions for removal from service shall be calculated from:

(i) the sum of actual emissions, as determined from company records, which have occurred during the two-year period immediately preceding date of permit application, or a different two year time period within the past five (5) years upon a determination by the Executive Officer that it is more representative of normal source operation, except annual emission declarations pursuant to Rule 301 may be used if less than the actual emissions as determined above; and

(ii) the total emissions in those two years shall be calculated on an annual basis.

PSD APPLICABILITY ANALYSIS:

The District is presently in attainment for the primary NAAQS for NOx, CO, SOx, and PM_{10}. For proposed modifications at existing major sources, PSD applies to each regulated pollutant for which the proposed emissions increase resulting from the modification both is significant and results in a significant net emissions increase. The following table summarizes the analysis to determine which pollutants are subject to PSD review.

Table 36 – Prevention of Significant Deterioration Applicability

	CO	NOx	SO_2	PM_{10}
Redondo Beach Generating Station Potential to Emit, TPY (*Table 10*)	70,693.4	632.3	34.1	430.9
Major Source?	Yes, PTE is 100 tpy or more for CO, NOx, and PM_{10}. If a source is a major source for any one regulated pollutant, it is considered to be a major source for all regulated pollutants.			
Redondo Beach Generating Station Actual Emissions (2011 & 2012 Avg), TPY (*Table 11*)	211.12	25.03	1.54	4.59
Redondo Beach Energy Project Potential to Emit, TPY = Emissions Increase (*Table 23*)	138.7	121.5	6.45	49.65
Does the RBEP result in a significant emissions increase?	Yes, increase is greater than 100 tpy.	Yes, increase is greater than 40 tpy.	No, increase is less than 40 tpy.	Yes, increase is greater than 15 tpy.
Net Emissions Increase (RBEP PTE – RBGS actual)	- 72.42	96.47	4.91	45.06
Does the RBEP result in a net significant emissions increase?	No, there is a **net decrease**.	Yes, net increase is greater than 40 tpy.	No, net increase is less than 40 tpy.	Yes, net increase is greater than 15 tpy.
PSD Applicable?	No	Yes	No	Yes

As the RBGS is a fossil fuel-fired steam electric plant of more than 250 million BTU/hr input, the major source threshold for the facility is 100 tons per year. The RBGS is an existing major stationary source as defined by Rule 1702(m)(1) because the potentials to emit for CO, NOx, and PM_{10} emissions all are 100 tpy or more. If a source is a major source for any one regulated pollutant, it is considered to be a major source for all regulated pollutants. CO is not subject to PSD because the increase is significant but the net increase is actually a decrease. SO2 is not subject to PSD because both the increase and net increase are less than the significant emissions threshold of 40 tpy. **NOx and PM_{10} are subject to PSD review** because the emissions increases and net emissions increases for both NOx and PM_{10} constitute significant increases.

- ***RULE 1703—PSD REQUIREMENTS***

The relevant PSD requirement sections are presented below, followed by the requirements analysis for each section. As determined above, the pollutants subject to PSD review are NOx and PM_{10}.

(a)(2) Each permit unit is constructed using BACT for each criteria air contaminant for which there is a net emission increase;

(a)(3) For each significant emission increase of an attainment air contaminant at a major stationary source:

(A) The applicant certifies in writing, prior to the issuance of the permit, that the subject stationary source shall meet 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 approved by appropriate federal, state, or District officials.

(B) The new source or modification will be constructed using BACT.

(C) The applicant has substantiated by modeling that the proposed source or modification, in conjunction with all other applicable emission increases or reductions (including secondary emissions) affecting the impact area, will not cause or contribute to a violation of:

(i) Any National or State Ambient Air Quality Standard in any air quality control region; or

(ii) Any applicable maximum allowable increase over the baseline concentration in any area.

(D) The applicant conducts an analysis of the ambient air quality in the impact area the new or modified stationary source would affect.... The applicant may rely on existing continuous monitoring data collected by the District if approved by the Executive Office...;

(E) The applicant provides an analysis of the impairment to visibility, soil, and vegetation that would occur as a result of the new or modified stationary source and the air quality impact projected for the baseline area as a result of general commercial, residential, industrial, and other growth associated with the source;

(F) The Executive Officer provides a copy of the complete application (within 10 days after being deemed complete by the District) 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....

PSD REQUIREMENTS ANALYSES:

1. ***Rule 1703(a)(2) & Rule 1703(a)(3)(B) Analysis—Top-Down BACT***

Each permit unit is required to be constructed using BACT for each criteria air contaminant for which there is a net emission increase.

BACT is defined in 40 CFR 52.21(b)(12) as: "an emissions limitation...based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 [New Source Performance Standards (NSPS)] and 61 [NESHAPS]...."

EPA outlines the process used to perform the case-by-case analysis, called a Top-Down BACT analysis, in a June 13, 1989 memorandum. The top-down analysis method was further discussed in the EPA's New Source Review Workshop Manual, October 1990.

The top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT. EPA has broken down this analytical process into the following five steps.

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

As required by PSD, top-down BACT analyses are presented below for the two pollutants subject to PSD review, NOx and PM_{10}. Although not subject to PSD review for RBEP, a top-down BACT analysis is also presented below for CO for the purpose of completeness.

A. Top-Down BACT Analysis for Combined Cycle Gas Turbine Power Block for Nitrogen Oxide (NOx) Emissions

The applicant is proposing control with dry low-NOx combustors and SCR to achieve emission rates of 2.0 ppm (1-hour) with and without duct burners, during normal operation.

Step 1: Identify all available control technologies.

NOx is a by-product of the combustion of natural gas-and-air mixture in the turbines and duct burners, which are high temperature environments. Thermal NO_X is created by the high temperature reaction in the combustion chamber between the nitrogen and oxygen in the combustion air. The heat from combustion causes the nitrogen (N_2) molecules in the combustion air to dissociate into individual N_2 atoms, which then combine with oxygen (O_2) molecules in the air to form nitric oxide (NO) and nitrogen dioxide (NO_2). The principal form of nitrogen oxide produced during turbine combustion is NO, but NO reacts quickly to form NO_2, creating a mixture of NO and NO_2 called NOx.

Combustion controls minimize the amount of NOx created during the combustion process. The control technologies include:

A. Water or Steam Injection
B. Dry-Low NOx (DLN) Combustors

Post- combustion controls remove NOx from the exhaust stream after the combustion has occurred. The control technologies include:

A. SCR
B. SCONOx (now EMx)
C. Selective Non-Catalytic Reduction (SNCR)

<u>Combustion Control Technologies</u>

A. <u>Water or Steam Injection</u>

The injection of water or steam into the combustor of a gas turbine quenches the flame and absorbs heat, reducing the combustion temperature. This temperature reduction reduces the formation of thermal NOx. Typically combined with a post-combustion control technology, water or steam injection alone can achieve a NOx emission of 25 part(s) per million dry volume (ppmvd) at 15 percent O2, but with the added economic, energy, and environmental expenses of using water.

B. Dry-Low NOx (DLN) Combustors

In conventional combustors, the fuel and air are injected separately and mixed by diffusion before combustion occurs. This method of combustion results in combustion "hot spots," which produce higher levels of NOx.

Lean premix and catalytic combustors are two types of DLN combustors that are available alternatives to the conventional combustors to reduce NOx combustion "hot spots."

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

Catalytic combustor technology is available under the trade name XONON. The XONON™ combustion system improves the combustion process by lowering the peak combustion temperature through the use of a catalyst to reduce the formation of thermal NOx. The combustion process is comprised of a partial combustion of the fuel in the catalyst module followed by a completion of the combustion downstream of the catalyst. In the catalyst module, a portion of the fuel is combusted without a flame at relatively low temperature to produce a hot gas. A homogenous combustion region is located immediately downstream where the remainder of the fuel is combusted.

Neither water injection nor DLN combustors can control NOx formed from the use of duct burners to supplementally fire the HRSGs in a combined-cycle configuration. NOx from duct burners is controlled by limiting the amount of duct firing required and by incorporating post-combustion pollution control technologies.

Post-Combustion Control Technologies

A. SCR

SCR is a post-combustion control technology designed to control NOx emissions from gas turbines, boilers, and other NOx-emitting equipment. The SCR system consists of a catalyst bed with an ammonia injection grid located upstream of the catalyst. The ammonia reacts with the NOx and oxygen in the presence of a catalyst to form nitrogen and water. The catalyst consists of a support system with a catalyst coating typically of titanium dioxide, vanadium pentoxide, or zeolite. A small amount of ammonia that is not consumed in the reaction is emitted in the exhaust stream and is referred to as "ammonia slip."

B. EMx™ (formerly SCONOx)

The EMx™ system uses a single catalyst to remove NOx emissions in the turbine exhaust gas by oxidizing NO to NO_2 and then absorbing NO_2 onto the catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx catalyst is from 300 to 700 degrees Fahrenheit (°F). EMx does not use ammonia, so there are no ammonia emissions from this catalyst system. When all of the potassium carbonate absorber coating has been converted to N_2 compounds, NOx can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N_2. Carbon dioxide (CO_2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

C. Selective Non-Catalytic Reduction (SNCR)

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

Step 2: Eliminate technically infeasible options.

Combustion Control Technologies

A. Water or Steam Injection

The use of water or steam injection is considered a feasible technology for reducing NOx emissions to 25 ppmvd when firing natural gas. When combined with SCR, water or steam injection can achieve 2 ppmvd NOx levels but at a slightly lower thermal efficiency as compared to DLN combustors.

B. Dry-Low NOx (DLN) Combustors

The use of lean premix combustors is a feasible technology for reducing NOx emissions from the RBEP. DLN combustors are capable of achieving 9 to 25 ppmvd NOx emission over a relatively large operating range (70 to 100 percent load), and when combined with SCR can achieve controlled NOx emissions of 2 ppmvd.

The XONON catalytic combustor has been demonstrated successfully in a 1.5-MW simple-cycle pilot facility and it is commercially available for turbines rated up to 10 MW. The technology has not been demonstrated, however, on an industrial E Class gas turbine, such as the proposed Mitsubishi Model 501DA turbines, rated at 131.9 MW. XONON™ is an innovative but not currently demonstrated technology that has received very limited trial operation. Therefore, the technology is not considered feasible for RBEP.

Post- combustion Control Technologies

A. SCR

The use of SCR, with an ammonia slip of less than 5 ppm, is considered a feasible technology for reducing NOx emissions to 2 ppmvd at 15 percent O2 when firing natural gas.

B. EMx™ (formerly SCONOx)

The use of EMx™ system is considered a feasible technology for reducing NOx emissions from RBEP.

In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Pio Pico Energy Center, PSD Permit No. SD 11-01, dated June 2012, the EPA noted that the EMx™ technology is a relatively newer technology that has yet to be demonstrated in practice on combustion turbines greater than 50 MW. The manufacturer has stated that it is a scalable technology and that NOx guarantees of <1.5 ppm are available.

In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant, PSD Permit No. SE 09-01, dated August 2011, the EPA noted that it is unclear what NO_X emission levels can actually be achieved by the technology. The EPA found only one BACT analysis that determined that EMx™/SCONOx was BACT for a large combustion turbine. However, the accompanying permit for the facility, Elk Hills Power in California, allowed the use of SCR or SCONOx to meet a permit limit of 2.5 ppm, and the actual technology that was installed in that case was SCR. The EPA noted that the Redding Power Plant in California, a 43 MW gas-fired combustion turbine, was permitted with a 2.0 ppm demonstration limit using SCONOx. In a letter dated June 23, 2005 from the Shasta County Air Quality Management District (Shasta County AQMD) to the Redding Electric Utility, however, it was determined that the unit could not meet the demonstration limit and, as a result, the limit was revised to 2.5 ppm. Based on these two examples, it appears that EMx™ has been demonstrated to achieve only 2.5 ppm.

The technology has not been demonstrated in practice on combustion turbines greater than 50 MW. The proposed Mitsubishi Model 501DA turbines are rated at 131.9 MW. EMx™ is carried forward in this BACT analysis as a potential NOx control technology. However, substantial evidence demonstrates that EMx™ is not yet demonstrated as technically feasible for the RBEP project.

C. Selective Non-Catalytic Reduction (SNCR)

SNCR is not considered technically feasible for the proposed RBEP. SNCR requires gas temperatures in the range of 1,600 to 2,100 °F that is higher than the exhaust temperatures from natural-gas-fired combustion turbine installations. For the proposed RBEP, the turbine exhaust temperature range is expected to be 372.6 to 415.2 °F.

Step 3: Rank remaining control technologies.

A summary of recent BACT limits for similar combined-cycle, natural gas-fired combustion turbines is provided in Table 37. The summary includes facilities for the period from 2004 to the present, as well as the IDC Bellingham facility permitted in 2000.

IDC Bellingham was included because it is the only known facility that was permitted with a BACT limit less than the 2.0 ppm, 1-hr average, proposed by RBEP. IDC Bellingham was permitted with a limit of 1.5 ppm during normal operations. However, this project was cancelled, so this limit has never been demonstrated as achievable. As shown in Table 37, all recently issued permits indicate that a limit of 2.0 ppm based on a 1-hr average represents the highest level of NO_X control.

Table 37—Summary of Recent NOx BACT Limits for Similar Combined-Cycle, Natural Gas-Fired Combustion Turbines

Facility	Permit Issuance	NOx Limit @ 15% O_2
LA City, DWP Scattergood Generating Station, California	2013	2.0 ppm (1-hr)
Pasadena City, Dept. of Water & Power, California	2013	2.0 ppm (1-hr)
Langley Gulch Power Plant, Idaho	2013	2.0 ppm (3-hr rolling)
El Segundo Power, LLC, California	2011	2.0 ppm (1-hr)
Lower Colorado River Authority, Texas	2011	2.0 ppm (24-hr)
Palmdale Hybrid Power Project, California	2011	2.0 ppm (1-hr)
Avenal Energy Project, California	2011	2.0 ppm (1-hr)
Warren County Power Station, Virginia	2010	2.0 ppm (1-hr)
Live Oaks Power Plant, Georgia	2010	2.5 ppm (3-hr)
Colousa Generating Station, California	2010	2.0 ppm (1-hr)
Victorville II Hybrid Power Project, California	2010	2.0 ppm (1-hr)
Pondera Capital Management, King Power Station, Texas	2010	2.0 ppm (1-hr)
Russell City Energy Center, California	2010	2.0 ppm (1-hr)
Madison Bell Energy Center, Texas	2009	2.0 ppm (24-hr rolling)
Chouteau Power Plant, Oklahoma	2009	2.0 ppm (1-hr)
Lamar Power Partners, Texas	2009	2.0 ppm (24-hr)
Patillo Branch Power Company, Texas	2009	2.0 ppm (24-hr)
FMPA Cane Island Power Park, Florida	2008	2.0 ppm (24-hr)
FPLWest County Energy Center Unit 3, Florida	2008	2.0 ppm (24-hr)
Kleen Energy Systems, Connecticut	2008	2.0 ppm (1-hr)
Blythe Energy LLC (Blythe II), California	2007	2.0 ppm (3-hr)
PSO Southwestern Power Plant, Oklahoma	2007	9.0 ppm (no averaging time)
Carlsbad Energy Center – NRG, California	2007	2.0 ppm (1-hr)
Rocky Mountain Energy Center, Colorado	2006	3.0 ppm (1-hr)
San Joaquin Valley Energy Center, California	2006	2.0 ppm (1-hr)
Elk Hills Power, California	2006	2.5 ppm (1-hr)
Inland Empire Energy Center, California	2005	2.0 ppm (1-hr)
Bicent (California) Malburg (formerly Vernon City, Light and Power Dept.), California	2003	2.0 ppm (1-hr)
Burbank City, Burbank Water & Power, SCPPA (Magnolia Power Plant), California	2003	2 ppm (3-hr)
LA City, DWP Haynes Generating Station, California	2002	2 ppm (1-hr)

The available control technologies are ranked according to control effectiveness in Table 38.

Table 38--NOx Control Technologies Ranked by Control Effectiveness

NOx Control Technology	Controlled Emission Rate (ppmvd @ 15% O_2, 1-hr average)
Water or Steam Injection	25
Dry Low-NOx Combustors (lean premix)	9 - 25
EMx^{TM} with Dry Low-NOx Combustors (lean premix)	2.5
SCR with Dry Low-NOx Combustors (lean premix)	2.0

Step 4: Evaluate most effective controls.

Based on the information presented in this BACT analysis, the proposed NOx emission rates of 2.0 ppm (1-hour) with and without duct burners are the lowest NOx emission rates achieved in practice at similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5: Select the BACT.

The proposed BACT for NOx emissions from the RBEP is the use of lean premix DLN combustors with SCR to control NOx emissions to 2.0 ppmvd (1-hour average) with and without duct burners.

Based on a review of the available control technologies for NOx emissions from natural gas-fired combustion turbines, the conclusion is that BACT for NOx emissions from the RBEP is the use of lean pre-mix DLN combustors with SCR to control NOx emissions to 2.0 ppmvd (1-hour average) with and without duct burners.

B. ***Top-Down BACT Analysis for Combined Cycle Gas Turbine Power Block for Particulate Matter (PM_{10}) Emissions***

The applicant proposes the use of good combustion practice, pipeline-quality natural gas, and inlet air filtration to control PM_{10} emissions to 4.5 lb/hr without duct burners and to 9.5 lb/hr with duct burners.

Step 1: Identify all available control technologies.

A. Combustion Control Technologies

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

B. Post-combustion Control Technologies

Two post-combustion control technologies designed to reduce particulate matter emissions from industrial sources are electrostatic precipitators and baghouses.

Step 2: Eliminate technically infeasible options.

Electrostatic precipitators and baghouses are typically used on solid/liquid-fuel fired or other types of sources with high particulate matter emission concentrations. Neither of these control technologies is appropriate for use on natural-gas-fired turbines because of the very low levels and small aerodynamic diameter of particulate matter from natural gas combustion. Therefore, electrostatic precipitators and baghouses are not considered technically feasible control technologies. However, best combustion practices, clean-burning fuels, and inlet air filtration are considered technically feasible for control of PM_{10} emissions from the RBEP.

Step 3: Rank remaining control technologies.

The use of best combustion practices, clean-burning fuels, and inlet air filtration are the technically feasible natural-gas-fired turbine control technologies. No add-on control devices are technically feasible to control PM_{10} emissions from natural-gas-fired turbines.

Step 4: Evaluate most effective controls.

Based on the information presented in this BACT analysis, using proposed good combustion practice, pipeline quality natural gas with a low sulfur content, and inlet air filtration to control PM_{10} emissions to 4.5 lb/hr without duct burners and to

9.5 lb/hr with duct burners is consistent with BACT at similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5: Select the BACT.

Based on the above review, the BACT for PM_{10} emissions from the RBEP is using good combustion practice, pipeline-quality natural gas, and inlet air filtration to control PM_{10} emissions to 4.5 lb/hr and 9.5 lb/hr, without and with duct burning, respectively.

3. ***Top-Down BACT Analysis for Combined Cycle Gas Turbine Power Block for Carbon Monoxide (CO) Emissions***

The applicant is proposing control with oxidation catalyst to achieve emission rates of 2.0 ppm (1-hour) with and without duct burners, during normal operation.

Step 1: Identify all available control technologies.

Combustion Control Technologies

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

Post- combustion Control Technologies

A. Oxidation Catalyst

An oxidation catalyst is typically a precious metal catalyst bed located in the HRSG. The catalyst enhances oxidation of CO to CO_2 without the addition of any reactant. Oxidation catalyst is a well-demonstrated technology for large combustion turbines.

B. EMx™ (formerly SCONOx)

The EMx™ system can reduce both NOx and CO from gas turbines. CO emissions are reduced by the oxidation of CO to CO_2 in the catalyst.

Step 2: Eliminate technically infeasible options.

Combustion Control Technologies
Good combustor design and best operating practices are technically feasible options for controlling CO emissions from the proposed RBEP.

Post- combustion Control Technologies
A. Oxidation Catalyst
The use of oxidation catalyst is considered a feasible technology for reducing CO emissions to 2 ppmvd at 15 percent O_2 when firing natural gas.

B. EMx™ (formerly SCONOx)
The use of EMx™ system is considered a feasible technology for reducing CO emissions from RBEP. In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant, PSD Permit No. SE 09-01, dated August 2011, the EPA noted it is unclear what level of control would be achieved by the technology on a long-term basis with a short (1-hr) averaging period. The manufacturer claims that emission rates below 1 ppm are achievable, but there is a lack of information that demonstrates this on large combustion turbines. EMx™ is carried forward in this BACT analysis as a potential NOx control technology. However, substantial evidence demonstrates that EMx™ is not yet demonstrated as technically feasible for the RBEP project.

Step 3: Rank remaining control technologies.

A summary of recent BACT limits for similar combined-cycle, natural gas-fired combustion turbines is provided in Table 39. The summary includes facilities for the period from 2004 to the present.

Table 39—Summary of Recent CO BACT Limits for Similar Combined-Cycle, Natural Gas-Fired Combustion Turbines

	Permit Issuance	CO Limit @ 15% O_2, without duct firing	CO Limit @ 15% O_2, with duct firing
LA City, DWP Scattergood Generating Station, California	2013	2.0 ppm (1-hr)	
Pasadena City, Dept. of Water & Power, California	2013	2.0 ppm (1-hr)	
Langley Gulch Power Plant, Idaho	2013	2.0 ppm (3-hr rolling)	
El Segundo Power, LLC, California	2011	2.0 ppm (1-hr)	2.0 ppm (1-hr)
Lower Colorado River Authority, Texas	2011	4.0 ppm (3-hr)	
Palmdale Hybrid Power Project, California	2011	2.0 ppm (1-hr) (3-yr demonstration period) 1.5 ppm (1-hr) (Post-demonstration)	2.0 ppm (1-hr) (3-yr demonstration & post-demonstration)
Avenal Energy Project, California	2011	2.0 ppm (1-hr) (3-yr demonstration period) 1.5 ppm (1-hr) (Post-demonstration)	2.0 ppm (1-hr) (3-yr demonstration & post-demonstration)
Warren County Power Station, Virginia	2010	1.5 ppm (1-hr)	2.4 ppm (1-hr)
Live Oaks Power Plant, Georgia	2010	2.0 ppm (3-hr)	3.2 ppm (3-hr)
Colousa Generating Station, California	2010	3.0 ppm (3-hr)	
Victorville II Hybrid Power Project, California	2010	2.0 ppm (1-hr)	3.0 ppm (1-hr)
Pondera Capital Management, King Power Station, Texas	2010	2.0 ppm (3-hr)	
Russell City Energy Center, California	2010	2.0 ppm (1-hr)	2.0 ppm (1-hr)
Madison Bell Energy Center, Texas	2009	17.5 ppm (1-hr rolling)	
Chouteau Power Plant, Oklahoma	2009	8.0 ppm (1-hr)	
Lamar Power Partners, Texas	2009	15 ppm (24-hr rolling)	
Patillo Branch Power Company, Texas	2009	2.0 ppm (3-hr rolling)	
FMPA Cane Island Power Park, Florida	2008	8.0 ppm (24-hr)	
Kleen Energy Systems, Connecticut	2008	0.9 ppm (1-hr)	1.8 ppm (1-hr)
Carlsbad Energy Center – NRG	2007	2.0 ppm (1-hr)	
Elk Hills Power, California	2006	4.0 ppm (1-hr)	
Inland Empire Energy Center, California	2005	3.0 ppm (1-hr)	
Bicent (California) Malburg (formerly Vernon City, Light and Power Dept.), California	2003	2.0 ppm (3-hr)	2.0 ppm (3-hr)
Burbank City, Burbank Water & Power, SCPPA (Magnolia Power Plant), California	2003	2.0 ppm (1-hr)	2.0 ppm (1-hr)
LA City, DWP Haynes Generating Station, California	2002	4.0 ppm (1-hr)	4.0 ppm (1-hr)

As the table demonstrates, most projects have CO emission rates that are the same as or higher than the CO emission rate proposed for the RBEP. Four projects, however, have CO emission rates that are lower than the CO emission rate proposed for the RBEP.

- Kleen Energy Systems, Connecticut
  This facility currently has the lowest permit limits for CO. The permit includes CO limits of 0.9 ppm and 1.8 ppm, on a 1-hr averaging basis for operating without and with duct burner, respectively. The initial source tests were performed in June 2011. Based on a November 2011 letter from the Connecticut Department of Energy & Environmental Protection, the facility was able to successfully demonstrate compliance with the CO emission limits of 0.9 and 1.7 ppmvd for unfired and fired operation, respectively.

  It should be emphasized that the Kleen Energy Systems permit provides an exemption from these limits during periods of "shifts between loads." Further, the permit does not specify limits for those periods of shifts between loads, which realistically can comprise a substantial percentage of normal operations. In contrast, the SCAQMD does require BACT during periods of shifts between loads. The Kleen Energy System limits do not meet the definition of BACT as implemented by the SCAQMD.

- Warren County Power Station, Virginia
  The final PSD permit includes CO emission limits of 1.5 ppm and 2.4 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively. Based on publicly available information, commercial operation is expected to occur in late 2014 or early 2015. Therefore, these CO emission levels are not considered to have been achieved in practice at this time.

- Avenal Energy Project, California
  The final PSD permit includes CO emission limits of 1.5 ppm and 2.0 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively, after a 3-year demonstration period during which the CO emissions limit is 2.0 ppm for operating without and with duct burner. However, the facility has not begun construction.

- Palmdale Hybrid Power Project, California
  The final PSD permit includes CO emission limits of 1.5 ppm and 2.0 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively, after a 3-year demonstration period during which the CO emissions limit is 2.0 ppm for operating without and with duct burner. However, the facility has not begun construction.

The available control technologies are ranked according to control effectiveness in Table 40. The controlled emission rates are from Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant, referenced above. Based on the lack of information for similar units, EMx™ is conservatively being compared as equivalent to oxidation catalyst.

Table 40--CO Control Technologies Ranked by Control Effectiveness

CO Control Technology	Controlled Emission Rate (ppmvd @ 15% O_2, 1-hr average without duct firing)	Controlled Emission Rate (ppmvd @ 15% O_2, 1-hr average with duct firing)
Good combustion practices	8.0 ppm	8.0 ppm
Oxidation catalyst and good combustion practices	0.9 - 2 ppm	2.0 - 2.4 ppm
EMx™ and good combustion practices	0.9 - 2 ppm	2.0 – 2.4 ppm

Step 4: Evaluate most effective controls.

Even assuming that EMx™ is equivalent to oxidation catalyst for controlling CO emission, it was determined to be not as effective as SCR for controlling NOx emissions. As EMx™ would not ensure that the BACT limit of 2.0 ppm NOx will be achieved, it is eliminated in this step due to environmental impacts.

Step 5: Select the BACT.

Based on the above review, the BACT for CO emissions from the RBEP is using good combustion practice and oxidation catalyst to control CO emissions to 2.0 ppm without and with duct burner.

2. ***Rule 1703(a)(3)(A) Analysis—Certification of Compliance***
Stephen O'Kane, Manager, AES Redondo Beach, LLC, provided a letter, dated 12/13/13, certifying that RBGS and all other facilities that are owned or operated by AES within California with all applicable emissions limitations, standards, rules, regulations and laws promulgated pursuant to the Clean Air Act.

3. ***Rule 1703(a)(3)(F) Analysis—Copy of Application to EPA, Federal Land Manager, Forest Service***
Permit applications for the subject project were submitted to the South Coast Air Quality Management District (SCAQMD) on 11/27/12 and were deemed complete by SCAQMD on 7/9/13. The cumulative impact assessment for the federal 1-hour NO_2 standard and the

visibility impact analysis for the Class II areas were subsequently completed and approved by SCAQMD on 12/11/13. On 12/19/13, the District sent to the affected officials listed below: (1) copy of complete application package, (2) the cumulative impact assessment for the federal 1-hour NO_2 standard and the visibility impact analysis for the Class II submitted by AES on 11/4/13, and (3) the SCAQMD modeling review memo dated 12/11/13.

Gerardo Rios, US EPA, Region IX
John Notar, Federal Land Manager, National Park Service
Mike McCorison, Air Quality Specialist, USDA Forest Services

In an e-mail dated 10/28/13 in response to a submittal by CH2M Hill, Tonnie Cummings, National Park Service, indicated that based on the Q/D, no air quality analysis is required for RBEP for Joshua Tree National Park. In a letter dated 2/12/14, Randy Moore, Regional Forester, USDA Forest Service, indicated the USDA Forest makes recommendations on PSD applications under the Clean Air Act as the Federal Land Manager. In summary, they do not anticipate any adverse AQRV impacts, including impacts on visibility, from this project in the modeled Class I wildernesses.

4. ***Rule 1703(a)(3)(D), (a)(3)(C), (a)(3)(E) Analysis—Air Impacts***

The air impacts analysis, including modeling, were performed for NO_2 and PM_{10}, as follows.

A. ***Rule 1703(a)(3)(D)--Pre-Construction Monitoring***

To ensure that the impacts from RBEP will not cause or contribute to a violation of an ambient air quality standard or an exceedance of a PSD increment, an analysis of the existing air quality in the project area is necessary. Preconstruction ambient air quality monitoring data is required for the purposes of establishing background pollutant concentrations in the impact area (40 CFR 52.21(m)). However, a facility may be exempted from this requirement if the predicted air quality impacts are less than the significant monitoring concentrations.

For NO_2, the significant monitoring concentration is 14 $\mu g/m^3$, annual average. For PM_{10}, the significant monitoring concentration is 10 $\mu g/m^3$, 24-hr average. (See 40 CFR 52.21(i)(5)(i)(b).) As discussed in the Rule 1303(b)(1) and Rule 2005(c)(1)(B) modeling analyses above, the maximum predicted NO_2 impact is 0.40 $\mu g/m^3$, annual average, and the maximum predicted PM_{10} impact is 1.75 $\mu g/m^3$, 24-hr average. Since the modeled impacts for NO_2 and PM_{10} are below the respective monitoring thresholds, the project is exempt from the pre-construction monitoring requirement. A facility may rely on air quality monitoring data collected at SCAQMD monitoring stations. The SCAQMD agreed that the background concentration data for NO_2 and PM_{10} from the SRA 3, Southwest Coastal LA County (No. 820) monitoring station is representative of the air quality in the subject area.

B. Rule 1703(a)(3)(C)—Air Quality Impacts Analysis

(1) National and State Ambient Air Quality Standards

As discussed under the Rule 1303(b)(1) and Rule 2005(c)(1)(B) modeling analyses above and the Rule 1703(a)(3)(C) PSD modeling analysis below, dispersion modeling demonstrates that NO_2 and PM_{10} will be in compliance with the primary NAAQS and the CAAQS.

(2) Class II PSD Increment

- *Significance Impact Levels (SILs)*
  If the significance impact levels (SILs) are exceeded, an analysis is required to demonstrate that the maximum allowable increments will not be exceeded. A SIL is the ambient concentration resulting from the facility's emissions, for a given pollutant and averaging period, below which the source is considered to have an insignificant impact. For NO_2 (annual), the SIL is 1.0 $\mu g/m^3$ (40 CFR 51.165). For NO_2 (1-hr), the interim SIL is 7.52 $\mu g/m^3$, as recommended in "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program" (EPA, 2010). For PM_{10}, the SIL is 5.0 μg/m3 (40 CFR 51.165).

- *Class II Increment Analysis*
  40 CFR 52.21(e) provides that international parks, national wilderness areas exceeding 5000 acres, national memorial parks exceeding 5000 acres, and national parks exceeding 6000 acres are designated as Class I areas. All other areas are designated as Class II areas. (40 CFR 52.21(g) provides for limited redesignation.) The RBEP is located in a Class II area. 40 CFR 52.21(c) sets forth the increment standards for Class I, Class II, and Class III areas. The increments are the maximum increases in pollutant concentration that are allowed to occur above the baseline concentration.

  The following table presents the maximum hourly and annual NO_2 impacts from the project, and the maximum predicted 24-hour PM_{10} impacts from the project, with a comparison to the respective Significant Impact Levels and the Class II PSD Increment Standards.

Table 41– Maximum Modeled Impacts (NO_2 and PM_{10}) Compared to Significant Impact Levels and PSD Class II Increment Standards

Pollutant	Averaging Time	Maximum Modeled Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant?	PSD Class II Increment Standard ($\mu g/m^3$)	Compliance?
NO_2	1-hr	31.91	7.52	Yes	--	Cumulative impact assessment required.
	Annual	0.4	1.0	No	25	Yes
PM_{10}	24-hr	1.75	5.0	No	30	Yes

As shown in the table above, the maximum predicted annual NO_2 impacts are below the Class II SIL. Therefore, the annual NO_2 impacts are less than significant, and no additional PSD analysis is required. Since the annual NO_2 impacts are based on 6835 hours of operation as shown in Table 28 above, condition no. A63.1 limits each turbine to 6835 hours per year, including startups and shutdowns, but not commissioning. Although further analysis to demonstrate compliance with the increment standard is not required, the above table includes the increment standard comparison for informational purposes.

The US EPA established a new 1-hour NO_2 standard of 0.10 ppm (188 $\mu g/m^3$) that became effective on April 12, 2010. In order to show compliance with the federal 1-hour NO_2 standard, the applicant used the maximum hourly emissions from startup, shutdown and normal operations. Given the number of startups and shutdowns, the emissions from these events cannot be considered as intermittent, as described in the US EPA's memo dated 3/1/2011. Emissions from commissioning were not included because commissioning is a once in a lifetime event and the form of the standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Therefore, commission emissions can be excluded. The maximum predicted 1-hour NO_2 impacts of 31.91 $\mu g/m^3$ exceed the Class II SIL of 7.52 $\mu g/m^3$, with a radius of impact with predicted concentrations greater than 7.52 micrograms per cubic meter (μg/m3) of 0.9 kilometers (km). Consequently, the applicant was required to assess the cumulative impacts of the RBEP and nearby sources for all receptors where RBEP impacts alone exceeded the 1-hour NO_2 SIL, instead of merely adding the predicted modeling impacts from RBEP to the background concentration for comparison to the ambient air quality standard. See cumulative impact assessment discussion below.

As shown in the table above, the maximum predicted 24-hour PM_{10} impacts are below the Class II SIL. Therefore, the 24-hour PM_{10} impacts are less than significant, and no additional PSD analysis is required. Although further analysis to demonstrate compliance with the increment standard is not required, the table includes the increment standard comparison for informational purposes.

Although CO is not a PSD pollutant for the RBEP project because the project will result in a net decrease in CO emissions, PRA staff provided a PSD analysis that is presented here for informational purposes. Peak 1-hour and 8-hour CO impacts, during turbine operations including startups and shutdowns, are 179.05 $\mu g/m^3$ and 38.36 $\mu g/m^3$, respectively, which are below the corresponding US EPA Class II significant impact levels of 2,000 $\mu g/m^3$ and 500 $\mu g/m^3$. Therefore, 1-hour and 8-hour CO increment analyses are not required.

- *Cumulative Impacts of the RBEP and Nearby Sources*
  The SCAQMD identified four facilities within 10 km of RBEP for inclusion in the cumulative impact assessment:

  - Exxon Mobil Oil Corporation (Facility ID 800089), located in Torrance, California with 29 emission sources,

  - Chevron Products Corporation (Facility ID 800030), located in El Segundo, California with 37 emission sources,

  - LADWP's Scattergood Generating Station (Facility ID 800075), located in Playa del Rey, California with four emission sources, and

  - El Segundo Power, LLC (Facility ID 115663), located in El Segundo, California with five emission sources.

These four facilities were selected to be included based on their facility emissions and distance to the project. Seasonal, by hour-of-day background concentrations from SRA 3, Southwest Coastal LA County (No. 820) monitoring station were used in the modeling.

The stack locations, stack parameters, and 1-hour NO_2 emission rates for the emission sources at these four facilities were provided by the SCAQMD. The cumulative impacts of the RBEP and nearby sources were assessed for all receptors where RBEP impacts alone exceeded the 1-hour NO_2 SIL.

The table below shows the maximum predicted cumulative 1-hour NO_2 impacts from RBEP operation plus cumulative projects plus background are below the federal 1-hour standard of 188 μg/m³. Therefore, no additional PSD analysis is necessary.

Table 42– RBEP and Nearby Sources Predicted 1-Hour NO_2 Impacts Compared to the NAAQS

Pollutant	Averaging Time	Total Predicted Concentration (μg/m3)	Primary NAAQS (μg/m3)	Compliance?
NO_2	1-hour	142.62	188	Yes

(3) ***Class I Area Impact Analysis***

A Class I impact analysis was conducted to demonstrate that the RBEP will not adversely affect air quality-related values (AQRVs) and will not cause or contribute to an exceedance of the Class I SIL or Increment Standards.

- *Air Quality Related Values*

  To evaluate the potential impacts on visibility and deposition at the nearest Class I area, the guidance provided in the Federal Land Manager's Air Quality Related Values Workgroup (FLAG) Phase I Report (revised 2010) allows an emissions/distance (Q/D) factor of 10 to be used as a screening criteria for sources located more than 50 km from a Class I area. This screening criterion includes all AQRVs. AQRVs are defined by the Federal Land Manager, and typically limit visibility degradation and the deposition of sulfuric acid and nitrogen. Emissions are calculated as the total SO_2, NOx, PM_{10}, and sulfuric acid annual emissions (in tpy, based on 24-hour maximum allowable emissions multiplied by 365 days) unless an emission source is limited to time periods shorter than 1 year. As condition no. A63.1 limits each turbine to an operating profile of 6835 hours per year, including startups and shutdowns, but not commissioning, the combined RBEP annual emissions of NOx (121.5 tpy), PM (49.7 tpy), SO_2 (6.4 tpy), and sulfuric acid (0 tpy) will be approximately 177.6 tpy, which is an annual equivalent of 228 tpy. Therefore, the maximum Q/D for the project will be approximately 4.3 ton/km-year, where Q is 228 tpy and D is 53 km, the distance to the nearest Class I area, San Gabriel Wilderness. Because the factor is less than the Federal Class I area air quality screening criteria of 10, visibility and deposition modeling is not required for any of the Class I areas because the potential impacts are expected to be less than significant.

As discussed above, in an e-mail dated 10/28/13, Tonnie Cummings, National Park Service, indicated that based on the Q/D, no air quality analysis is required for RBEP for Joshua Tree National Park. In a letter dated 2/12/14, Randy Moore, Regional Forester, USDA Forest Service, indicated the USDA Forest makes recommendations on PSD applications under the Clean Air Act as the Federal Land Manager. In summary, they do not anticipate any adverse AQRV impacts, including impacts on visibility, from this project in the modeled Class I wildernesses.

- *Class I Increment Analysis*
  EPA requires an analysis addressing Class I increment impacts for the applicable pollutants regardless of the results of the Class I AQRV analysis. To evaluate the potential impacts on Class I areas near the RBEP site, all Class I areas within 300 km of RBEP were identified. Based on this survey, the San Gabriel Wilderness, which is approximately 53 km from the RBEP site, was identified as the nearest Class I area. To address the PSD Class I Increment thresholds, AERMOD was used with a receptor ring at 50 km from the facility. (50 km is the maximum receptor distance of the AERMOD model.) The ring was spaced in 5-degree increments centered on the RBEP site location. If modeled impacts are below the SILs, then the project would be considered to have negligible impact at the more distant Class I areas.

  The following table presents a summary of the predicted annual NO_2 impacts and a comparison to the Class I Significance Impact Level. The predicted impacts from the operation of the RBEP are below the SIL, therefore comparison with the increment standard is not required but provided here for informational purposes. Since the impact is below the SIL, the project would have a negligible impact at the more distant Class I areas and actual ambient air quality impacts at Class I areas are not required to be determined.

Table 43– Predicted Impacts Compared to the Class I SIL and Increment Standard

Pollutant	Averaging Period	Maximum Predicted Impact at 50 km ($\mu g/m^3$)	Significance Impact Level ($\mu g/m^3$)	PSD Class I Increment Standard ($\mu g/m^3$)
NO_2 [1]	Annual	0.01	0.1	2.5

[1] The annual NO_2 concentration conservatively assumes a complete conversion of NOx to NO_2.

C. ***Rule 1703(a)(3)(E)—Additional Impacts: Visibility, Soil and Vegetation Impacts as Result of Growth***

In addition to assessing the ambient air quality impacts expected for a proposed new source, the PSD regulations require the evaluation of other potential impacts on (1) growth, (2) soils and vegetation, and (3) visibility impairment. The depth of the analysis generally depends on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area.

(1) ***Growth***

The growth component involves a discussion of general commercial, residential, industrial, and other growth associated with RBEP. RBEP consists of the replacement of existing electrical generating utility boilers with newer more efficient combustion turbines that will be entirely located within the existing RBGS facility boundaries. As such, RBEP is not anticipated to result in general commercial, residential, industrial, or other growth. The resulting ancillary growth is not expected to result in material impacts to air quality or impairment to visibility, soils, and vegetation. The City of Redondo Beach and the general project area is already heavily developed and is adjacent to the Los Angeles metropolitan area. Because of the existing stock of housing and industrial and commercial services and the fact that RBEP will replace existing electrical generation within the western Los Angeles basin, RBEP is not expected to require or cause any material offsite growth that could impair soils or vegetation. During RBEP construction, it is not anticipated that the work force will cause any increase to preexisting housing and services. The limited work force and outside services required for the RBEP's operation once construction is complete also will not materially affect the area. Lastly, by locating RBEP on an existing power plant site and due to the urban nature of the project area, the project is not expected to induce growth or to result in impacts to soils and vegetation.

(2) ***Soil and Vegetation Impacts***

The additional impact analysis includes consideration of potential impacts to soils and vegetation associated with RBEP. This component generally includes: (a) a screening analysis to determine if maximum modeled ground-level concentrations of project pollutants could have an impact on plants; and (b) a description of soils and vegetation that may be affected by proposed project emissions and the potential impacts on such soils and vegetation associated with RBEP.

- *Secondary NAAQS*
  For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects, because the secondary NAAQS levels are set to protect public welfare, including animals, plants, soils, and materials.

  The dispersion modeling required for Rule 1303(b)(1) and Rule 2005(c)(1)(B) also demonstrates that NO_2, SO_2 and PM_{10} will be in compliance with the secondary NAAQS, as shown the table below. EPA has not promulgated secondary NAAQS for CO.

Table 44- Model Results – Start up/Shutdown and Normal Operation – Compliance with Secondary NAAQS

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)[2]	Total Predicted Concentration ($\mu g/m^3$)	Federal Standard, Secondary NAAQS ($\mu g/m^3$)	Compliance?
NO_2	Annual	0.40	29.9	30.3	100	Yes
SO_2	3-hour	2.74	38.7	41.44	1,300	Yes
PM_{10}	24-hour	1.75	52	53.75	150	Yes

- *Nitrogen Deposition Impacts*
  RBEP's Data Response Set 1A, including responses to Data Requests 8-10, 13, and 20-24, dated 12/6/13, was prepared in response to CEC Staff Data Requests 1 through 47 for the AFC, dated 10/15/13.

  Responses to Biological Resources Data Requests 20-24 address nitrogen deposition impacts. Impacts of excessive nitrogen deposition to plant communities include direct toxicity and changes in species composition among native species such as enhancement of nonnative invasive species. CEC staff believed that nitrogen deposition resulting from emission of nitrogen oxides (NOx) and ammonia (NH_3) during operation of the proposed project could have negative impacts on biological resources nearby if the nitrogen deposition plume covers these areas.

  The applicant's analysis of impacts associated with potential nitrogen deposition from the RBEP includes the following determinations. Referenced Tables DR20-1 and DR21-2 can be found in RBEP's Data Response Set 1A.

- The Applicant estimates that the existing baseline nitrogen deposition rates near the project site are less than or equal to 2 kilograms-nitrogen per hectare per year (kg-N ha^{-1} yr^{-1}) because the RBEP project and neighboring biological resource areas are within 5 kilometers of the coastline where the background deposition rate ranges from 1 or 2 kg-N ha^{-1} yr^{-1}. The Applicant conducted a literature review to identify critical load (CL) rates for the various biologically sensitive communities within 6 miles of RBEP, with the habitat types and CL summarized in Table DR20-1.

- The wet and dry nitrogen deposition resulting directly from depositional nitrogen emissions from the three combustion turbines at the proposed RBEP were evaluated using AERMOD (Version 12345). The maximum modeled annual deposition over 5 years was combined with a conservative estimated background deposition rate of 2 kg-N ha^{-1} yr^{-1} and compared to the CL for nitrogen deposition for each of the habitat types present in the wetland areas. The results of the deposition modeling are shown in Table DR21-2. In each case, the maximum predicted nitrogen deposition was less than the CL deposition. Because the potential effects are below the CL, no detrimental ecological effect will occur as a result from the RBEP project. Therefore, even with the use of the conservative methodology for estimating nitrogen deposition discussed in detail, any contribution of nitrogen deposition from RBEP would have a less-than-significant impact on sensitive species habitat located near the project site.

- <u>*Additional Soil and Vegetation Impacts Analyses*</u>
Section 5.2 Biological Resources of the AFC indicates the site is entirely developed with no natural habitats present. Vegetation observed was limited to landscaping trees and shrubs and a few scattered weedy plants. Most of the non-landscape vegetation was observed in the small ponded area immediately west of fuel oil storage tank #1 and in the southwest corner of the fuel oil storage tank #1 containment area. Species in these areas consisted of a few cattails (*Typha* sp.) and what appears to be sprangletop (*Leptochloa* sp.), an opportunistic weedy species often found in moist, disturbed areas. No special-status plant species were observed within the project area. Five special-status plant species are known to occur or have occurred within 1 mile of RBEP: beach spectacle-pod, Brand's star phacelia, aphanisma, Parish's brittlescale, and south coast saltscale. The RBEP site is located entirely within existing developed

areas with no suitable habitat; therefore, the project will not affect any special-status plant species.

All construction and demolition activities will be located in existing developed areas where no additional clearing or grading of natural vegetation will be required. Furthermore, no new offsite linears will be needed as a result of this project; therefore, there would be no construction- or demolition-related disturbance to natural vegetation or habitats on offsite areas.

Air emissions from the combustion turbine exhaust stacks include nitrogen oxides, sulfur dioxide, carbon monoxide, volatile organic compounds, and particulates. Nitrogen oxide gases convert to nitrate particulates in a form that is suitable for uptake by most plants and could be used to promote plant growth and primary productivity. RBEP involves replacing existing electrical generating utility boilers with newer more efficient combustion turbines that will be entirely located within an existing developed area. Sensitive natural communities within 10 miles of RBEP include southern coastal bluff scrub, southern coastal salt marsh, and southern dune scrub. Many ecosystems in the western United States are nitrogen limited and are expected to show growth responses to increased nitrogen deposition. Most of the land use in the immediate vicinity of RBEP is urban development. Although critical habitat for the western snowy plover is within 1 mile of the RBEP site, there is generally a low percentage of vegetation cover in the area. Most vegetation cover near RBEP consists of landscaping plants, and there is a general lack of natural habitats in the area. In addition, given the predominant easterly wind direction and photochemistry required to convert gaseous nitrogen-based air emissions to particles, it is expected that actual aerial nitrogen deposition would occur east of RBEP, including the greater Los Angeles metropolis, and is unlikely to affect any sensitive natural communities. In addition, existing vegetation systems have successfully developed in an environment that includes the emissions from the existing RBGS, which will be shut down with the startup of RBEP. Therefore, aerial deposition of nitrogen to the surrounding area from RBEP emissions is expected to result in a less-than-significant impact on soil-vegetation systems.

Particulate emissions will be controlled by inlet air filtration of the turbine air intakes and the use of low sulfur natural gas. The deposition of particulates can affect vegetation through either physical or chemical mechanisms. Physical mechanisms include the blocking of stomata so that normal gas exchange is impaired, as well as potential effects on leaf adsorption and reflectance of solar radiation. Information on physical effects is scarce, presumably in part because such effects are slight or not obvious except under extreme situations. Sulfur dioxide can affect vegetation by degrading chlorophyll, reducing photosynthesis, raising respiration rates, changes in protein metabolism, lipid and water balance and enzyme activity. High concentrations cause leaf necrosis, while longer term exposure leads to chronic injury resulting in reduced plant growth and greater susceptibility to climatic extremes or pathogens.

Therefore, with the shutdown of the existing RBGS and the use of low-sulfur natural gas, best combustion practices, emission controls, and monitoring that will be incorporated into the RBEP design, impacts from RBEP operating emissions will be less than significant and no additional mitigation measures are required.

(3) ***Visibility Impairment--Class II Area Analysis***

The additional impact analysis also evaluates the potential for visibility impairment (e.g., plume blight) associated with RBEP. In a letter dated 1/25/13, USEPA provided comments for LA City, DWP Scattergood Generating Station, a repowering project with a similar design configuration. The EPA commented that the PSD additional impacts analysis should also consider visibility impacts on Class II areas.

Consequently, the applicant provided a quantitative visibility analysis for Class II areas within 50 km of RBEP. The visibility analysis was performed using the VISCREEN plume modeling program per the procedures outlined in the "Workbook for Plume Visual Impact Screening and Analysis" (EPA, 1992), the Park Service's IMPROVE network suggested visual range, and the AERMOD meteorological data. The VISCREEN Tier I and II assessments were conducted using criteria for Class I areas, as currently there are no thresholds for visibility impacts on Class II areas. However, even using the conservative approach, the modeled results from the visual assessment demonstrates that RBEP would not adversely affect visibility at nearby Class II areas.

The applicant conducted a survey of California State Parks and Wilderness areas designated as Class II areas within 50 km of RBEP. The five Class II areas, identified by the applicant and approved by the SCAQMD for inclusion in the analysis, were evaluated.

The *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report – Revised (2010)* [Federal Land Manager [FLM], 2010] guidance document for addressing Class I areas initially recommends the use of the U.S. Environmental Protection Agency's (EPA) VISCREEN screening model to assess the plume contrast and color contrast (ΔE) when compared to the sky and terrain backgrounds. The VISCREEN screening model can use a tiered approach to determine if the facility's emissions would impact visibility at a nearby Class I area. If the VISCREEN Tier I and Tier II screening assessment demonstrate that visibility could be impacted at the Class I area, then the PLUVUE II model is recommended for a Tier III assessment. The PLUVUE II model differs from the VISCREEN screening model as VISCREEN uses a single representative worst-case meteorological condition to determine the facility's potential impacts on visibility while PLUVUE II considers a realistic array of all conditions that would be expected to occur in a typical year in the region. Procedures outlined in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA, 1992) were followed to conduct a visibility assessment with VISCREEN at the nearby Class II areas.

The VISCREEN screening model was developed to present a visual effect evaluation of emissions from a source as observed from a given vantage point on either a sky or terrain background. Emissions input into the model are assumed to travel along an infinitely long, straight line toward the specified area of concern. As mentioned above, the VISCREEN screening model allows for the use of a tiered approach to assess a proposed source's impacts on visibility. A Tier I assessment utilizes conservative assumptions for both plume characteristics and dispersion conditions to determine if the plume would have an impact on visibility. If a Tier I assessment exceeds the FLAG guidance levels of concern for Class I areas of 2.0 for ΔE and 0.05 for the perceptibility threshold, then a Tier II assessment would be conducted. A Tier II assessment provides a more realistic representation of the possible worst-case meteorology and plume transport for a specific area to be analyzed.

The following table summarizes the VISCREEN Tier I modeled results for each Class II area evaluated. The maximum modeled values for color contrast and plume contrast are presented for inside the area analyzed, regardless of the VISCREEN modeled lines of sight for the observer. Bold values exceed the Class I significant impact criterion.

Table 45– PSD Class II Tier I VISCREEN Results

Class II Area	Minimum Distance	Maximum Distance	Variable	Sky	Terrain	Criteria[1]
Kenneth Hahn State Park	16.9	18.9	Color Contrast	1.011	**2.79**	2.0
			Plume Contrast	0.01	0.018	|0.05|
Will Rogers State Park and Topanga State Park[2]	24.6	34.7	Color Contrast	1.247	1.772	2.0
			Plume Contrast	-0.013	0.013	|0.05|
Malibu Creek State Park and Malibu Lagoon State Park[3]	33.2	43.6	Color Contrast	0.911	1.208	2.0
			Plume Contrast	0.009	0.011	|0.05|

1 Levels of concern for Class I areas were used because no specific requirements or criteria exist for assessing Class II visibility impacts (Federal Land Managers [FLM], 2010).
2 Assumed Will Rogers State Park and Topanga State Park cover the same area since they are directly adjacent to one another.
3 Assumed Malibu Creek State Park and Malibu Lagoon State Park cover the same area since they are directly adjacent to one another.

As shown in the table above, the results of the Tier I assessment demonstrate that the proposed RBEP will be below the significance criterion for both color difference and contrast at Will Rogers State Park, Topanga State Park, Malibu Creek State Park, and Malibu Lagoon State Park. The Tier I assessment, however, showed the criterion for color contrast is exceeded at Kenneth Hahn State Park. As a result, a Tier II assessment was performed for Kenneth Hahn. Using the 5-year meteorological data from the SCAQMD's LAX meteorological station, the joint frequency distribution tables were created, which was used to determine the worst-case single wind speed and stability class required for a Tier II VISCREEN analysis. The Tier II assessment results are summarized in the table below.

Table 46- PSD Class II Tier II VISCREEN Results

Class II Area	Minimum Distance	Maximum Distance	Wind Speed[1]	Stability[1]	Variable	Sky	Terrain	Criteria[2]
Kenneth Hahn State Park	16.9	18.9	3	E	Color Contrast	0.387	0.795	2.0
					Plume Contrast	0.004	0.004	|0.05|

1 The Joint Frequency Distribution table used to calculate the wind speed and stability for the Tier II assessment is presented in Attachment 4 of the letter from Stephen O'Kane to Mohsen Nazemi, dated 11/4/13.

2 Levels of concern for Class I areas were used because no specific requirements or criteria exist for assessing Class II visibility impacts (FLM, 2010).

The VISCREEN Tier II assessment indicates the Kenneth Hahn State Park does not exceed the criterion for color contrast or plume contrast. As the modeled results are below the conservative Class I area criterion for both color difference and contrast, RBEP will not adversely affect visibility at these or other nearby Class II areas.

Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases

Rule 1714 was adopted into the SIP on 12/10/12, and became effective on 1/9/13. Upon the effective date, the SCAQMD became the Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permitting authority for sources located within the SCAQMD.

The relevant rule sections are as follows.

(a) This rule sets forth preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714.

(c) The provisions of 40 CFR Part 52.21 are incorporated by reference, with the excluded subsections of 40 CFR Part 52.21 listed in (c)(1).

(d)(1) An owner or operator must obtain a PSD permit pursuant to this rule before beginning actual construction, as defined in 40 CFR 52.21(b)(11), of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively.

In May 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule), in which EPA defined six GHG pollutants (collectively combined and measured as carbon dioxide equivalent [CO_2e]) as NSR-regulated pollutants and therefore subject to PSD permitting, including the preparation of a BACT analysis for GHG emissions.

The EPA's PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011, provide applicability criteria. Under Tailoring Rule Step 2, the PSD Applicability Test for GHGs in PSD

Permits Issued on or after July 1, 2011 indicates that PSD applies to the GHG emissions from a proposed modification to an existing source if any of three sets of applicability criteria are met. The set of applicability criteria applicable to the RBEP is as follows:

- Modification is otherwise subject to PSD (for another regulated NSR pollutant), and has a GHG emissions increase and net emissions increase:
  - Equal to or greater than 75,000 TPY CO_2e, and
  - Greater than -0- TPY mass basis

PSD APPLICABILITY ANALYSIS FOR GHGs:

As discussed under the Rule 1703 analysis above, the modification is otherwise subject to PSD for other regulated NSR pollutants, NOx and PM_{10}. The following table summarizes the analysis to determine whether GHGs are subject to PSD review.

Table 47– Prevention of Significant Deterioration Applicability for Greenhouse Gases

	CO_2e
GHG Emissions Increase = Redondo Beach Energy Project Potential to Emit *(Table 25)*	1,718,926.8 TPY > 75,000 TPY and > 0 TPY mass basis
Redondo Beach Generating Station Actual Emissions (2011 & 2012 Avg) *(Table 11)*	361,143.42 TPY
GHG Net Emissions Increase = RBEP PTE – RBGS actual	1,357,783.38 TPY > 75,000 TPY and > 0 TPY mass basis
PSD for Greenhouse Gases Applicable?	Yes

The greenhouse gases are subject to PSD review because the emissions increase and net emissions increase constitute significant increases.

PSD REQUIREMENTS ANALYSES:

The "PSD and Title V Permitting Guidance for Greenhouse Gases" explains that under the Clean Air Act and applicable regulations, a PSD permit must contain emissions limitations based on application of BACT for each PSD regulated NSR pollutant. A determination of BACT for GHGs should be conducted in the same manner as it is done for any other PSD regulated pollutant. EPA recommends that permitting authorities continue to use the Agency's five-step "top down" BACT process to determine BACT for GHGs. No other PSD requirements were enumerated.

PSD requirements generally include pre-construction ambient monitoring, air impacts analyses, and other impacts analysis, as discussed under Rule 1703 for the criteria pollutants. As there are currently no NAAQS, CAAQS, SILs or PSD increments standards established for GHGs, the air impacts analysis requirement is not applicable. Further, EPA does not require pre-construction monitoring for GHGs in accordance with 40 CFR 52.21(i)(5)(iii) and 51.166(i)(5)(iii), or Class I areas impact analysis.

Top-Down BACT Analysis

1. Top-Down BACT Analysis for Combined Cycle Gas Turbine Power Block for Carbon Dioxide (CO_2) Emissions

The primary sources of GHG emissions will be the natural-gas-fired combustion turbines with duct burners. The primary combustion emission is CO_2, because the CH_4 and N_2O are insignificant.

Step 1: Identify all available control technologies.

As determined by EPA and the Department of Energy, the available CO_2 control technologies are:

A. Carbon capture and storage (CCS)
B. Lower Emitting Alternative Technology
C. Thermal efficiency

A. Carbon Capture and Storage/Sequestration (CSS)

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

CO_2 Capture and Compression. Three capture technologies are primarily being considered for CCS: pre-combustion, post-combustion, and oxy-combustion. Pre-combustion capture refers to a process in which a hydrocarbon fuel is gasified to form a synthetic mixture of hydrogen and CO. The CO is converted to CO_2, using shift reactors, and captured before combusting the hydrogen-based fuel. The post-combustion capture technologies include three methods, namely sorbent adsorption, physical adsorption, and chemical absorption. Oxy-combustion technology uses air separators to remove the nitrogen from combustion air so that the combustion products are almost exclusively CO_2, thereby reducing the volume of exhaust gases needed to be treated by the carbon capture system. Of these technologies, the post-combustion technology is most applicable to RBEP.

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

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

After separation, the CO_2 must be compressed to supercritical temperature and pressure for suitable pipeline transport and geologic storage properties. Although compressor systems for such applications are proven commercially available technologies, incorporation of CO_2 compression equipment will require the installation of specialized equipment with high operating energy requirements.

A recent similar analysis conducted for LADWP Scattergood Generating Station determined that commercially available systems are not available to capture flue gas from a commercial power plant.

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

Because of the extremely high pressures, as well as the unique thermodynamic and dense-phase fluid properties of supercritical CO_2, specialized designs are required for CO_2 pipelines. Control of potential propagation fractures and corrosion also require careful attention to contaminants such as O_2, N_2, CH_4, water, and hydrogen sulfide.

While transport of CO_2 via pipeline is proven technology, doing so in urban areas will present additional concerns. Development of new rights–of-way in congested areas would require significant resources for planning and execution, and public concern about potential for leakage may present additional barriers. Securing a right-of-way easement on public property for the installation and operation of a high-pressure CO_2 pipeline could result in extensive delays due to resolving concerns raised by the public based on the perceived hazards associated with the pipeline. Securing sufficient private property for siting a CO_2 pipeline would be cost prohibitive within the urban Los Angeles basin.

The Technical Advisory Committee for the California Carbon Capture and Storage Review Panel stated in the August 2010 report that there are no existing CO_2

pipelines in California. In addition, there are no CO_2 pipeline projects underway in California.

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

With geologic sequestration, a suitable geological formation is identified close to the proposed project, and the CO_2 captured from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet. Below this depth, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water that already resides in the pore space would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water, and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2. No pilot studies of CO_2 injection into onshore or offshore geologic formations in the vicinity of the project site have been conducted to date.

B. <u>Lower Emitting Alternative Technology</u>

Commercially available and low or non-GHG emitting power production technology include geothermal, hydroelectric, biomass fueled, solar power, nuclear powered, and wind facilities. Section 6 of the AFC presents a review of alternatives to the RBEP technology. The review considered alternative technologies that could have reduced environmental impacts, while satisfying the project objectives. Alternative generating technologies, including geothermal plants, hydroelectric plants, biomass-fired plants, solar plants, and wind generation plants, were considered but rejected due to the inability of these technologies to provide generating capacity for local reliability needs, meet peak energy demands, and provide controllable and flexible generation with minimum environmental effects.

The proposed RBEP design and operation consists of one 3-by-1 combined-cycle generating power block. The applicant has determined that this configuration is the only alternative that meets all of the project objectives. Several of the primary objectives of the RBEP are to backstop variable renewable resources with a multiple-stage generator project that incorporates fast-start capability, a high degree of turndown, fast ramping capability, and a high thermal efficiency. The lower GHG emitting technologies would fundamentally redefine the project and alter the business purpose. The EPA does not require a BACT analysis to redefine the applicants' project. As a result, no additional lower emitting alternative technologies are feasible to incorporate into the project without changing the business purpose of the project.

C. **Thermal Efficiency**

Power generation through fossil fuel combustion is a chemical reaction process. Because CO_2 emissions are directly related to the quantity of fuel burned, the less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. The thermal efficiency is defined as the dimensionless ratio of the useful work performed by the process and the heat input to the process. The RBEP efficiency is expected to vary from 30% to over 50%, depending on many factors. 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 conditions.

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

The RBEP proposes to combust natural gas, the lowest emitting fossil fuel available. The proposed design will consist of a combined-cycle generation system, which has a higher thermal efficiency than a simple cycle system. Energy is recovered in the heat recovery steam generator (HRSG) and is used to generate power in the steam turbine generator (STG). The fast start capability of the turbines minimizes emissions during startup and increase the efficiency of the power plant.

Although new power generating system would emit GHG emissions, the high thermal efficiency of new power generating equipment and the system build-out of renewable resources in California would result in a net cumulative reduction of GHG emissions from new and existing fossil resources.

With the adoption of Senate Bill 2 on April 12, 2011, California's Renewable Portfolio Standard was increased from 20 percent by 2010 to 33 percent by 2020. To meet the new RPS requirements, the amount of dispatchable, high-efficiency, natural gas generation used as regulation resources, fast ramping resources, or load following or supplemental energy dispatches will have to be significantly increased.

The construction of the RBEP will aid in the effort to meet California's RPS standard. Finally, the operation of the new power generating system will enhance the overall efficiency of AES's electricity system operation and thereby reduce GHG emissions.

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

A. <u>Carbon Capture and Storage</u>

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

CO_2 Capture and Compression. Three fundamental types of carbon capture systems are employed throughout various process and energy industries: sorbent adsorption, physical absorption, and chemical absorption.

- ***Sorbent Adsorption.*** Sorbent-based capture technology can be used for post-combustion capture of CO_2. However, the technology has not been demonstrated on combined-cycle gas turbine power plants. Commercial-scale systems currently in operation contain a significantly higher concentration of CO_2 in the exhaust. A sorbent-based carbon capture process is currently judged to be technologically infeasible for a natural gas-fired commercial power plant application.

- **Physical Absorption.** Physical absorption technology is commercially available for CO_2 removal but has not been demonstrated in practice for power generation applications. Commercial-scale systems currently in operation contain a significantly higher concentration of CO_2 in the exhaust. A physical absorption capture process is currently judged to be technologically infeasible for a commercial power plant application.

- **Chemical Absorption.** A chemical solvent CCS approach would be required to capture the approximate 3 to 5 percent CO_2 emitted from the flue gas generated from the natural-gas-fired systems (combined-cycle) used at the RBEP facility. To date, a chemical solvent technology has not been demonstrated at the operating scale proposed. A solvent-based carbon capture process is currently judged to be technologically infeasible for a commercial power plant application.

Carbon 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.

Carbon Storage. The following discusses the potential use of deep saline aquifers, compressed CO_2 to enhance oil recovery in crude oil production operations, and ocean sequestration as potential options for the storage of captured CO_2.

- ***Enhanced Oil Recovery (EOR).*** Although the CO_2 could be used for EOR applications in the vicinity of RBEP, only pilot-scale projects are known in the region, and only estimates are available on the capacity of these miscible oil fields. Therefore, the exact location, time frame, and needed flow rates for those existing or future EORs are unclear because this information is typically treated as being a trade secret. Furthermore, the feasibility of obtaining the necessary permits to build infrastructure and a pipeline to transport CO_2 to these fields through a densely urbanized area is uncertain.

  The potential to sell CO_2 to industrial or oil and gas operations is infeasible for an operation such as RBEP, where daily operation depends on grid dispatch needs, particularly to offset reductions from renewable energy sources. Even if a potential EOR opportunity could be identified, such an operation would typically need a steady supply of CO_2. Intermittent CO_2 supply from potentially short duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable.

  At this time, the technical feasibility of using enhanced oil recovery for CO_2 storage for the new power generating system cannot be determined. Therefore CCS using enhanced oil recovery cannot be demonstrated to be technically feasible in practice for the new power generating system.

- ***Deep Saline Aquifer.*** At this time, the technical feasibility of using deep saline aquifer injection for CO_2 storage for the new power generating system cannot be determined. Based on mapping by DOE's National Energy Technology Laboratory's NatCarb viewer, the nearest known saline aquifer sites, located in New Mexico, Utah, and Texas, are undergoing early phases of evaluation. Therefore CCS using enhanced oil recovery cannot be demonstrated to be technically feasible in practice for the new power generating system.

- ***Ocean Sequestration.*** The effectiveness of ocean sequestration as a full-scale method for CO_2 capture and storage is unclear given the limited availability of injection pilot tests and the ecological impacts to shallow and deep ocean ecosystems. Ocean sequestration is conducted by injecting supercritical liquid CO_2 from either a stationary or towed pipeline at targeted depth interval, typically below 3,000 feet. Long-term effects on the marine environment, including pH excursions, are uncertain. Ocean storage and its ecological impacts are still in the research phase, and not commercially available.

Summary of CCS Feasibility

According to *EPA's New Source Review Workshop Manual* (EPA, 1990): "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

On January 8, 2014, the EPA proposed a new NSPS for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines that is potentially applicable to the proposed turbines for RBEP. (79 Fed. Reg. 1430) The action proposes standards for natural gas-fired combustion turbines (NGCC) that are based on modern, efficient natural gas combined cycle technology as the best system of emission reduction. The action proposes a separate standard of performance for fossil fuel-fired electric utility steam generating units and integrated gasification combined cycle units that burn coal, petroleum coke and other fossil fuels that is based on partial implementation of carbon capture and storage as the best system of emission reduction.

The EPA noted that, at this time, CCS has not been implemented for NGCC units, and the EPA believes there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units. The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream. The cyclical operation of the NGCC, combined with the low concentration of CO_2 in the flue gas stream, means that the EPA cannot assume that the technology for the coal-fired units can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC .

In summary, post-combustion carbon capture technologies are still in the developmental stage or installed on pilot scale projects. These technologies are not commercially available for the project size of a full-scale commercial power plant. Consequently, CSS is not yet demonstrated as technically feasible for the RBEP project.

B. **Lower Emitting Technology**

As discussed above, commercially available lower emitting technology was determined to be infeasible for the site as it would fundamentally alter the business purpose of the source.

C. **Thermal Efficiency**

California has established an emissions performance standard for California power plants to quantify feasible energy efficiency levels. Senate Bill (SB) 1368 limits long-term investments in baseload generation by the state's publicly owned utilities to power plants that meet an emissions performance standard jointly established by the CEC and the California Public Utilities Commission (CPUC). The resulting CEC regulations, as codified in California Code of Regulations (CCR), Chapter 11, Article 1, establish a standard for baseload generation (defined as with a capacity factor of at least 60 percent) of 1100 pounds CO_2 per megawatt-hour $_{net}$. This standard is further discussed below under the rule analysis, which includes thermal efficiency calculations. The applicant has provided thermal efficiency calculations for the expected operating schedule that demonstrates the RBEP, with a thermal efficiency of 1063.3 lb CO_2 /MWh-HHV_{net} (exclusive of degradation), can meet the 1100 lb CO_2/MWh $_{net}$ standard. The thermal efficiency is expected to be 1148.4 lb CO_2 /MWh-HHV_{net} (inclusive of degradation).

As discussed above under *CCS Feasibility*, the EPA proposed new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines that are potentially applicable to the proposed turbines for RBEP. This action proposes standards for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle technology as the best system of emission reduction. New stationary combustion turbines with a base load rating heat input to the turbine engine of greater than 850 MMBtu/hr (250 MW), such as the proposed RBEP turbines, would be required to meet a standard of 1,000 lb CO_2/MWh $_{gross}$ on a 12-operating month rolling average. This rule is still in subject to public comments and final action by EPA, but may become part of Subpart KKKK or create a new subpart TTTT. Therefore, SCAQMD staff has evaluated its compliance, in case it becomes final and subject to this project in its final form. This standard is further discussed below under the rule analysis, which includes thermal efficiency calculations. The applicant has provided thermal efficiency calculations for the permitted operating schedule that demonstrates the RBEP with thermal efficiency of 974.3 lb CO_2 /MWh-HHV_{gross} (including degradation) can meet the 1000 lb CO_2/MWh_{gross} standard.

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 carbon capture and sequestration (CCS) and lower emitting alternative technology were determined to be infeasible for the RBEP project, these options are not carried forward in the BACT analysis to Step 3. The remaining feasible technology is:

Thermal efficiency

Thermal Efficiency

Thermal efficiency is capable of lowering GHG emissions. The new power generating system already incorporates increased thermal efficiency in its design by incorporation of the combined cycle configuration. Since the parasitic load will be relatively low at this facility, further increases to thermal efficiency are not achievable without changing basic objectives of the power project, if at all, and hence are not required by EPA guidelines for GHG BACT.

Step 4: Evaluate the most effective controls.

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

The remaining feasible technology is:

Thermal efficiency

Thermal Efficiency

As CCS and lower emitting alternative technologies are not technically feasible, thermal efficiency remains the most effective, technically feasible GHG control technology for the RBEP.

As discussed under Step 1, California's Renewable Portfolio Standard requirement was increased from 20 percent by 2010 to 33 percent by 2020. The RBEP will aid in the effort to meet California's RPS standard because a significant attribute of the RBEP is that the combined-cycle facility can operate similarly to a peaking plant but at higher thermal efficiency. The addition of the high thermal efficiency of the RBEP's generation to the state's electricity system will also facilitate the integration of renewable resources in

California's generation supply and will displace other less-efficient, higher GHG-emitting generation. This allows an increased use of wind power and other renewable energy sources, with backup power available from the RBEP.

During the project definition phase, AES evaluated other turbine models to determine the best fit with the project objectives. The turbines evaluated include the following classes of combustion turbines: B/D/E, F/G, H/J, and aeroderivative turbines in both combined and simple cycle configurations. The evaluation was based on compliance with SCAQMD Rule 1304(a)(2), start/ramp ability, fuel pressure requirements, combustion turbine exhaust characteristics driving the steam cycle conditions, start up/shutdown reliability and emission profiles, water consumption requirements, and particulate matter emission rates. The projected heat rates for a General Electric LMS100 in a simple cycle configuration, a Siemens Flex-10 plant in a combined cycle configuration, and the RBEP were compared. Measured against the project objectives of fast starting and ramping with high thermal efficiency over the entire range of electrical output, the Mitsubishi 501D selected for RBEP satisfies the majority of the project objectives.

A database review of BACT determinations identified six recently-permitted facilities with natural gas-fired combustion turbines for which a GHG BACT analysis was performed. Each of the projects proposed the use of combined-cycle configurations to produce commercial power, and the BACT analyses for each of the projects concluded that thermal efficiency was the only feasible combustion control technology.

- EPA issued the PSD Permit for the Palmdale Hybrid Power Project in October 2011. This project consists of a hybrid of natural gas fired combined cycle generating system (two GE 7FA combustion gas turbines and one shared steam turbine) integrated with solar thermal generating system. Based on EPA's analysis CCS was eliminated as a control option because it was deemed economically infeasible.

- EPA issued the PSD Permit for the Lower Colorado River Authority (LCRA) Project in November 2011. This project consists of a natural gas fired combined cycle generating system with two GE 7FA combustion gas turbines and a shared steam turbine. Based on the review of the available control technologies for GHG emissions, EPA concluded that BACT for LCRA was the use of new thermally efficient combustion turbines with applicable GHG emission limit.

- The Bay Area Air Quality Management District issued the PSD permit for the Calpine Russell City Energy Center in 2010. According to a presentation by Calpine, thermal efficiency was the only feasible combustion control technology considered as CCS was determined to be not commercially available. Thermal efficiency was found to be the top level of control feasible for a combined-cycle power plant, and hence was the technology selected at GHG BACT for Russell City.

- EPA issued the PSD Permit for the Pio Pico Energy Center Project in November 2012. The project consists of three simple cycle GE LMS100 generators. EPA concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

- SCAQMD issued the PSD Permit for the LA City, DWP Scattergood Generating Station in 2013. The project consisted of one GE 7FA combined cycle gas turbine and two simple cycle GE LMS100 generators. SCAQMD concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

- SCAQMD issued the PSD Permit for the Pasadena City, Dept. of Water & Power in 2013. The project consisted of one LM6000 combined cycle gas turbine. SCAQMD concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

As demonstrated by the EPA and SCAQMD permits, thermal efficiency is the most cost effective control technology for GHG emissions from power plants. The Mitsubishi 501DA combustion turbines are acceptable for GHG PSD permits under the BACT thermal efficiency requirement.

Step 5: Select the BACT.

Based on the above analysis, thermal efficiency is the only technically and economically feasible alternative for CO_2/GHG emissions control for the RBEP project. The current design of the facility meets the BACT requirement for GHG emission reductions.

BACT also requires applicable GHG emission limits. Condition E193.6 implements the California EPS of 1100 lb CO_2/MWh_{net} standard, and condition E193.7 implements the proposed NSPS standard of 1000 lb CO_2/MWh_{gross}.

Condition E193.6 limits the GHG (CO_2) emissions to 572,378 tons per year per turbine (Table 25). The calendar average GHG emissions will be limited to 1063.3 lbs per net megawatt-hours (1148.4 lbs per new megawatt-hours inclusive of equipment degradation). Condition E193.7 limits GHG (CO_2) emissions to 1000 lbs per gross megawatt-hour, or the applicable limit which is published in the final EPA rule, if RBEP meets the applicability criteria. For both conditions, compliance will be based on a 12-month rolling average basis based on fuel usage. These conditions are further discussed under the rule analysis for the California EPS and the proposed NSPS standard, respectively.

2. ***Top-Down BACT Analysis for Sulfur Hexafluoride (SF_6) Emissions***

The only GHG emitted from circuit breakers is sulfur hexafluoride (SF_6). SF_6 is used as a gaseous dielectric medium in electrical circuit breakers, switching equipment, and other high voltage electrical components. The RBEP circuit breakers will have a potential for fugitive emissions of SF_6 through leaks.

Step 1: Identify all available control technologies.

The following control technologies are potentially available.

A. Circuit Breakers Not Containing GHGs

Dielectric oil and compressed air circuit breakers do not contain any GHG pollutants. No other alternative materials to SF_6 are currently available.

B. Totally Enclosed SF_6 Circuit Breakers with Leak Detection Systems

These breakers are designed as a totally enclosed hermetically sealed pressure system with a specified maximum leak rate and an alarm warning when a certain percentage of the SF_6 has escaped. The best equipment can be guaranteed to leak at a rate of no more than 0.5 weight percent per year. The use of an alarm identifies potential leak problems to allow the amount leaked to be minimized.

No add-on control options for GHG emissions are currently available due to the nature of the electrical system containing the SF_6.

Step 2: Eliminate technically infeasible options.

Both control options are technically feasible.

Step 3: Rank remaining control technologies.

Dielectric oil or compressed air circuit breakers would have a CO_2e emission rate of 0 tpy.

Enclosed-pressure SF_6 circuit breakers with 0.5% (by weight) annual leakage rate and leak detection systems would have a CO_2e emission rate of 17.8 tons per calendar year, as calculated above.

Step 4: Evaluate the most effective controls.

Despite decades of research to develop a desirable alternative to SF_6, none has been developed. SF_6 remains the preferred gas for electrical insulation and for arc quenching and current interruption equipment used in the transmission and distribution of electricity. The following properties make SF_6-based circuit breakers superior to the alternatives: (1)

high thermal conductivity, (2) high dielectric strength, and (3) fast thermal and dielectric recovery. In addition, the National Institute of Standards and Technology (NIST) reported in 1977 that equipment insulated with SF_6 uses significantly less land and has relatively low radio and audible noise emissions, relative to dielectric oil and compressed air circuit breakers. Therefore, dielectric oil and compressed air circuit breakers are eliminated as the top-ranked control option because of adverse environmental and energy impacts.

Step 5: Select the BACT.

Based on the above review, BACT for the circuit breakers is the use of enclosed-pressure SF_6 circuit breakers with a maximum annual leakage rate of 0.5% by weight and a 10% by weight leak detection system, and an annual emission cap.

The above BACT determination is in agreement with the EPA's determination for the Pio Pico Energy Center. The Pio Pico PSD permit included conditions requiring the installation of enclosed-pressure SF_6 circuit breakers with a maximum annual leakage rate of 0.5% by weight. The circuit breakers were required to be equipped with a 10% by weight leak detection system, which was required to be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations were required to be maintained on site. The CO_2e emissions from the circuit breakers were subject to an annual emissions limit.

Further, EPA stated in a response to public comment that the BACT requirements to equip the circuit breakers with a leak detection system and appropriately calibrate such system are not redundant to CARB's Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (California Code of Regulations, Subchapter 10, Article 4, Subarticle 3.1, §95350-§95359).

Accordingly, facility condition F52.2 is included to enforce the BACT requirements for circuit breakers, using the same language as in the Pio Pico PSD permit. Annual CO_2e emissions from circuit breakers will be limited to 17.8 tons per calendar year, based on emissions calculations above.

Regulation XX—RECLAIM

- ***Rule 2005—New Source Review for RECLAIM***
  This rule sets forth pre-construction review requirements for modifications to RECLAIM facilities.

  - ***(c)(1)(A)--BACT***
    See the *Rule 1703(a)(2)—Top-Down BACT* analysis, above.

- ***(c)(1)(B)--Modeling***
  This provision requires the applicant to perform air dispersion modeling to substantiate that the installation of a new source which results in an emission increase of NO_2 will not result in a significant increase in the air quality concentration for NO_2. See the NO_2 modeling analyses performed for Rules 1303(b)(1) and 1703(a)(3)(C).

- ***(c)(2)—Offsets***
  Paragraph (c)(2) requires RECLAIM facilities to hold sufficient RTCs to offset the first year of operation's emissions increase from a new, relocated, or modified source before commencement of such operation. Until Rule 2005 was amended on 6/3/11, Rule 2005(f)(1) required RECLAIM facilities to hold RTCs for each subsequent compliance year prior to each compliance year for the same sources. Further, facilities subject to this NSR hold requirement were generally required to hold and not transfer out of their Allocation accounts the specified RTCs for each year until the compliance year was over.

  On 6/3/11, Rule 2005 was amended to remove existing facilities that do not have emissions greater than the level of their 1994 allocation plus non-tradable credits (NTCs) from paragraph (f)(1). Per Rule 2000(c)(35), an existing facility is "any facility that submitted Emission Fee Reports pursuant to Rule 301 – Permit Fees, for 1992 or earlier years, or with valid District Permits to Operate issued prior to October 15, 1993, and continued to be in operation or possess valid District permits on October 15, 1993." Per Rule 2000(c)(51), a new facility is "any facility which has received all District Permits to Construct on or after October 15, 1993."

  Existing facilities are only subject to the "hold" requirement for the first year of operation of each source with an emissions increase (the period commencing at the start of operation and concluding 364 days later; 365 days later if the period includes a leap day). EPA has approved that amendment into the SIP.

  A memo, dated 5/1/12, provided implementation guidelines. Attachment II – "Facilities with Condition I296" to the memo indicates AES Redondo Beach is an existing Cycle 1 facility with emissions less than the level of their 1994 allocation plus non-tradable credits. Therefore, condition I297 is applicable to this facility.

  Rule 2005(d) specifies the RECLAIM credit calculation shall be based on the potential to emit or on a permit condition limiting the source's emissions.

  - <u>RTCs for Turbines with Duct Burners</u>
    On Pg. 5.1-32 of the AFC, footnote a to Table 5.1-35—SCAQMD NOx RECLAIM Requirements requests that the first-year RTC calculation include the commissioning month emissions and the full 12-month normal operating year emissions.

First year RTCs for turbine and duct burner = 8282.4 lb/month, commissioning (Table 16) + 81,003.1 lb/normal operating year (Table 22) = 89,286 lb/yr

(The requested 89,286 lb/yr is more conservative than the 82,535 lb/yr from Table 21 that is based on one month of commissioning and eleven months of normal operation.)

The 89,286 lb/yr for each turbine includes the emissions from the associated duct burner. The current RECLAIM Administration policy requires separate I297 conditions for the turbine and the duct burner with the RTCs apportioned based on relative ratings. It is recognized that this method of apportioning will not and is not required to accurately reflect anticipated NOx emissions from the turbine versus the duct burner. The NOx emissions from the turbine and duct burner will continue to be measured by a single CEMS in the exhaust stack.

<u>Turbine RTCs (I297.1, I297.3, I297.5)</u>
[(1492 MMBtu/hr, turbine) / (1492 MMBtu/ hr, turbine + 507 MMBtu/hr, duct burner)] * [89,286 lb/yr RTCs] = 66,641 lb/yr RTCs

<u>Duct Burner RTCs (I297.2, I297.4, I297.6)</u>
[(507 MMBtu/hr, duct burner) / (1492 MMBtu/ hr, turbine + 507 MMBtu/hr, duct burner)] * [89,286 lb/yr RTCs] = 22,645 lb/yr RTCs

- <u>RTCs Required to Be Purchased Prior to Issuance of Turbine Permits</u>
  Startup and testing of the new power block is scheduled for first and second quarter 2019, and completion of construction/start of commercial operations scheduled for the third quarter 2019.

  Section B: RECLAIM Annual Emission Allocation, printed 1/15 /14, indicates the NOx RTC holding for 1/2019 through 12/2019 is 293,987 lbs NOx.

  As each turbine/duct burner requires a total of 89,268 lb/yr, the three turbines/duct burners require a total of 267,867 lb/yr.

  The total required 267,867 lb/yr is less than the 293,987 lb/yr available for 2019. Therefore, RTCs do not need to be purchased before the issuance of the turbine permits.

- ***<u>(e)--Trading Zone Restrictions</u>***
  See Rule 1303(b)(3) analysis above.

- ***<u>(g)—Additional Federal Requirements for Major Stationary Sources</u>***
  For (g)(1) - (g)(4), see Rule 1303(b)(5) analysis above.

- ***(h)—Public Notice***
  See Rule 212 analysis above.

- ***(i)—Rule 1401 Compliance***
  See Rule 1401 analysis above.

- ***Rule 2012-RECLAIM Monitoring Recording and Recordkeeping Requirements***
  Rule 2012(c)(1)(C) classifies "any gas turbine rated greater than or equal to 2.9 megawatts excluding any emergency standby equipment or peaking unit " as a "major NOx source." Since the duct burner, rated at 507 MMBtu/hr, is part of the turbine, it is also a "major source." Further, (c)(1)(A)(ii) classifies any heater with a maximum rated capacity of 500 million Btu per hour or more irrespective of annual heat input as a "major NOx source."

  Rule 2012(h)(6) provides that the Facility Permit holder which installs a new major source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting, and recording systems no later than 12 months after the initial start up of the major NOx source. During the interim period between the initial start up of the major NOx source and the provisional certification date of the CEMS, the Facility Permit holder shall comply with the monitoring, reporting, and recordkeeping requirements of paragraphs (h)(2) and (h)(3) of this rule. (Condition D82.2 implements this requirement.)

  Paragraph (h)(2) provides that interim reports shall be submitted monthly for major and large sources. Paragraph (h)(3) provides that the Facility Permit holder shall install, maintain, and operate a totalizing fuel meter for each major source. Rule 2012, Appendix A, Chapter 2 states on pg. Rule 2012A-2-1 that major sources shall be allowed to use an interim reporting procedure to measure and record NOx emissions on a monthly basis according to the requirements specified in Chapter 3 for large sources. Chapter 3 states on pg. Rule 2012A-3-1 that the interim reporting is specified in subdivision D, paragraph 1. Paragraph 1, in turn, provides that the interim reporting shall be based on fuel usage and emission factor(s).

  Thus, the facility permit is required to set forth the NOx emission factors for use in the interim reporting period before the CEMS is certified. Condition A99.1 specifies the interim emission factor for the commissioning period during which the CTGs are assumed to be operating at uncontrolled levels. From Table 17 above, the emission factor is 13.08 lb/mmcf. Condition A99.2 specifies the interim emission factor for the normal operating period after commissioning has been completed and before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels. From Table 19 above, the emission factor is 8.88 lb/mmcf.

Regulation XXX—Title V Permits
The proposed project is considered as a "significant permit revision" to the RECLAIM/Title V permit for this facility. Rule 3000(b)(31) specifies that a "significant permit revision" includes "installation of new equipment subject to a New Source Performance Standard (NSPS) pursuant to 40 CFR Part 60, or

a National Emission Standard for Hazardous Air Pollutants (NESHAP) pursuant to 40 CFR Part 61 or 40 CFR Part 63."

Pursuant to Rule 3003(j), a proposed permit incorporating this permit revision will be submitted to EPA for a 45-day review. Pursuant to Rule 3006(a), all public participation procedures will be followed prior to the issuance of the permit.

Pursuant to Rule 3006(a)(1)(B) , the public notice is required to include 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 SCAQMD 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 whom 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.

The Title V public notice will be combined with the Rule 212(g) notice. The public notice periods for both are anticipated to run concurrently for a single 30-day public comment period. (The Rule 212 public notice requirements are discussed above under the *Rule 212* analysis above.)

FEDERAL REGULATIONS

Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (January 8, 2014)

On January 8, 2014, EPA withdrew the proposal for the new source performance standard (NSPS), Subpart TTTT, for carbon dioxide emissions, which was published on April 13, 2012, for new affected fossil fuel-fired electric utility generating units. In a separate action on the same day, the EPA proposed new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines that are potentially applicable to the proposed turbines for RBEP. (79 Fed. Reg. 1430)

The EPA is considering two options for codifying the requirements for the new proposed NSPS. Under the first option EPA is proposing to codify the standards of performance for the respective sources within existing 40 CFR Part 60 subparts. Applicable GHG standards for electric utility steam generating units would be included in subpart Da and applicable GHG standards for stationary combustion turbines would be included in subpart KKKK. In the second option, the EPA is co-proposing to create a new subpart TTTT (as in the original proposal for this rulemaking) and to include all GHG standards of performance for covered sources in that newly created subpart. (79 Fed. Reg. 1436-1437)

This rule is still in subject to public comments and final action by EPA, but may become part of Subpart KKKK or create a new subpart TTTT. Therefore, compliance is evaluated below, in case the proposal becomes final and subject to this project in its final form.

The key requirements of the new proposed NSPS that are applicable to stationary combustion turbines are summarized below, with the rule analysis following.

- *Applicability*
  The standards of performance are proposed to apply to a stationary combustion turbine if it meets the following five applicability conditions: (1) Commenced construction after [DATE OF PUBLICATION IN THE FEDERAL REGISTER]; (2) Has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h); (3) Combusts fossil fuel for more than 10.0 percent of the heat input during any 3 consecutive calendar years; (4) Combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis; and (5) Was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis. (79 Fed. Reg. 1445-1446, 1506, 1511) The facility's sale of more than one-third of its potential electric output is referred to as the "one-third sales criterion," and the amount of potential electric output supplied to a utility power distribution system is referred to as the "capacity factor." (79 Fed. Reg. 1459)

- *Emissions Standards*
  This action proposes standards for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle technology as the best system of emission reduction. (79 Fed. Reg. 1436) New stationary combustion turbines with a base load rating heat input to the turbine engine of greater than 850 MMBtu/hr (250 MW), such as the proposed RBEP turbines, would be required to meet a standard of **1,000 lb CO_2/MWh gross** on a 12-operating month rolling average. New combustion turbines that have a design heat input to the turbine engine greater than 250 MMBtu/hr (73 MW) and equal to or less than 850 MMBtu/hr (250 MW) would be required to meet a standard of 1,100 lb CO_2/MWh gross on a 12-operating month rolling average. (79 Fed. Reg. 1446-1447, 1506, 1510, 1511, 1516) The emission limits would apply to affected sources upon the effective date of the final action. (79 Fed. Reg. 1446)

  This action proposes to regulate CO_2 only, and not other greenhouse gases (GHGs). Separate emissions limit for other GHGs, such as methane or nitrous oxide, are not being proposed. (79 Fed. Reg. 1446) Under this proposed NSPS, an affected facility is a new emissions generating unit (EGU). The rule is not proposing standards for modified or reconstructed sources. However, since both a new and existing power plant can add new EGUs to increase generating capacity, this NSPS will apply to both a new, Greenfield EGU facility or an existing facility that adds EGU capacity by adding a new EGU that is an affected facility under this NSPS. (79 Fed. Reg. 1489)

The proposed method to determine compliance with the applicable CO_2 emissions standard is to calculate the CO_2 mass emissions rate for the affected stationary combustion turbine by using the hourly CO_2 mass emissions and total gross output data determined and recorded for the compliance period. Only operating hours for which valid data is obtained for all parameters can be used to determine the hourly CO_2 mass emissions and gross output data. Operating hours must not be included in which the substitute data provisions of part 75 of this chapter was used for any of the parameters in the calculation. Valid hourly CO_2 mass emission values must be obtained for a minimum of 95 percent of the operating hours in the compliance period. The total CO_2 mass emissions are calculated by summing the hourly CO_2 mass emissions values for the affected stationary combustion turbine that are determined to be valid for all of the operating hours in the applicable compliance period. For each operating hour of the compliance period used to calculate the total CO_2 mass emissions, the affected stationary combustion turbine's corresponding hourly gross output must be determined. The hourly gross energy output must be determined for each operating hour in which there is no electric output, but there is mechanical output or useful thermal output. In addition, the hourly gross CO_2 emissions must be determined for each operating hour in which there is no useful output. The total gross output for the affected stationary combustion turbine's compliance period are calculated by summing the hourly gross output values for the affected stationary combustion turbine for all of the operating hours in the applicable compliance period. The CO_2 mass emissions rate for the affected stationary combustion turbine is calculated by dividing the total CO_2 mass emissions value by the total gross output value. If the CO_2 mass emissions rate for the affected stationary combustion turbine is less than or equal to the applicable CO_2 emissions standard, then the affected stationary combustion turbine is in compliance with the emissions standard. **If the average CO_2 mass emissions rate is greater than the applicable CO_2 emissions standard, then the affected stationary combustion turbine has excess CO_2 emissions.** (79 Fed. Reg. 1507 – 1508, 1513-1514)

- *Startup, Shutdown, and Malfunction Requirements*
  In the compliance calculation, periods of startup and shutdown are included as periods of partial load. (79 Fed. Reg. 1448) In the event that a source fails to comply with the standard as a result of a malfunction event, the EPA would determine an appropriate response based on, among other factors, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the standard was, in fact, "sudden, infrequent, not reasonably

preventable" and was not instead "caused in part by poor maintenance or careless operation." (79 Fed. Reg. 1449)

- *Continuous Monitoring*

  The proposed rule would require owners or operators of EGUs that combust **solid fuel** to install, certify, maintain, and operate continuous emission monitoring systems (CEMS) to measure CO_2 concentration, stack gas flow rate, and (if needed) stack gas moisture content in accordance with 40 CFR Part 75, in order to determine hourly CO_2 mass emissions rates (tons/hr). (79 Fed. Reg. 1450)

  The proposed rule would allow owners or operators of EGUs that burn exclusively **gaseous or liquid fuels** to install fuel flow meters as an **alternative** to CEMS and to calculate the hourly CO_2 mass emissions rates using Equation G–4 in Appendix G of part 75. To implement this option, hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of the fuel are also required, in accordance with Appendix D of part 75. (79 Fed. Reg. 1450, 1507, 1512)

  In addition to requiring monitoring of the CO_2 mass emission rate, the proposed rule would require EGU owners or operators to monitor the hourly unit operating time and "gross output", expressed in megawatt hours (MWh). The gross output includes electrical output plus any mechanical output, plus 75 percent of any useful thermal output. (79 Fed. Reg. 1450) EGU owners and operators would be required to install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the gross electric output from the affected facility. (79 Fed. Reg. 1507, 1513)

  The proposed rule would require EGU owners or operators to prepare and submit a monitoring plan that includes both electronic and hard copy components, in accordance with §§ 75.53(g) and (h). (79 Fed. Reg. 1450-1451, 1507, 1512) The electronic portion of the monitoring plan would be submitted to the EPA's Clean Air Markets Division (CAMD) using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. The hard copy portion of the plan would be sent to the applicable State and EPA Regional office. Further, all monitoring systems used to determine the CO_2 mass emission rates would have to be certified according to § 75.20 and section 6 of Appendix A to part 75 within the 180-day window of time allotted under § 75.4(b), and would be required to meet the applicable on-going quality assurance procedures in Appendices B and D of part 75. The proposed rule would require all valid data collected and recorded by the monitoring systems (including data recorded during startup, shutdown, and malfunction) to be used in assessing compliance. Failure to collect and record required data is a violation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of stack emissions (e.g., calibration error tests, linearity checks, and required zero and span adjustments). (79 Fed. Reg. 1450-1451)

As discussed above, the proposed rule would allow the use of only the operating hours in the compliance period for the compliance determination calculation if valid data are obtained for all parameters used to determine the hourly CO_2 mass emissions and the gross output data are used for the compliance determination calculation. The compliance determination must not include operating hours in which the substitute data provisions of part 75 of this chapter was used for any of those parameters in the calculation. (79 Fed. Reg. 1451, 1507-1508, 1513-1514)

The proposed rule would require 95 percent of the operating hours in each compliance period to be valid hours, i.e., operating hours in which quality assured data are collected and recorded for all of the parameters used to calculate CO_2 mass emissions. (79 Fed. Reg. 1451, 1508, 1513) EGU owners or operators would have the option to use backup monitoring systems, as provided in §§ 75.10(e) and 75.20(d), to help meet this proposed data capture requirement. (79 Fed. Reg. 1451)

- *Emissions Performance Testing Requirements*
  In accordance with § 75.64(a), the proposed rule would require an EGU owner or operator to begin reporting emissions data when monitoring system certification is completed or when the 180-day window in § 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). For EGUs subject to the 1,000 lb CO_2/MWh gross standard or the 1,100 lb CO_2/MWh gross emission standard, the initial performance test would consist of the first 12-operating months of data, starting with the month in which emissions are first required to be reported. **The initial 12-operating month compliance period would begin with the first month of the first calendar year of EGU operation in which the facility exceeds the capacity factor applicability threshold.** Following the initial compliance determination, the emission standard would be met on a 12-operating-month rolling average basis. (79 Fed. Reg. 1451)

- *Continuous Compliance Requirements*
  The proposed rule specifies that compliance with the 1,000 lb/MWh and 1,100 lb/MWh CO_2 mass emissions rate limits would be determined on a 12-operating month rolling average basis, updated after each new operating month. For each 12-operating-month compliance period, quality-assured data from the certified Part 75 monitoring systems would be used together with the gross output over that period of time to calculate the average CO_2 mass emissions rate. The proposed rule specifies that the first operating month included in the initial 12-operating-month compliance period would be the month in which reporting of emissions data is required to begin under § 75.64(a), i.e., either the month in which monitoring system certification is completed or the month in which the 180-day window allotted to finish certification testing expires (whichever month is earlier). The rule is proposing that initial compliance with the applicable emissions limit be calculated by dividing the sum of the hourly CO_2 mass emissions values by the total gross output for the 12-operating-month period. (79 Fed. Reg. 1451)

- *Notification, Recordkeeping, and Reporting Requirements*
  The proposed rule would require an EGU owner or operator to comply with the applicable notification requirements in §§ 75.61, 60.7(a)(1) and (a)(3) and 60.19. (79 Fed. Reg. 1452, 1508, 1514)

  The proposed rule would require the maintenance of records of the information used to demonstrate compliance with this NSPS. The proposed rule would also require the applicable recordkeeping requirements in subpart F of part 75 to be met. Records must be kept of the calculations performed to determine the total CO_2 mass emissions for: (1) Each operating month (for all affected units); (2) Each compliance period, including, as applicable, each 12-operating month compliance period. Records must be kept of the applicable data recorded and calculations performed that were used to determine the affected stationary combustion turbine's gross output for each operating month. Records must be kept of the calculations performed to determine the percentage of valid CO_2 mass emission rates in each compliance period. Records must be kept of the calculations performed to assess compliance with the applicable CO_2 mass emissions standard. Records must be kept of the calculations performed to determine any site-specific carbon-based F-factors used in the emissions calculations (if applicable). (79 Fed. Reg. 1452, 1509, 1514)

  Records must be in a form suitable and readily available for expeditious review. Each record must be kept for 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record to demonstrate compliance with a 12-operating month emissions standard. Each record must be kept on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. Records may be kept off site and electronically for the remaining year(s). (79 Fed. Reg. 1452, 1509, 1514-1515)

  For stationary combustion turbines that are required to conduct initial and on-going compliance determinations on a 12-operating month rolling average basis for the applicable CO_2 mass standard, the owners/operators would be required to submit electronic quarterly reports as follows. After the first 12-operating months for the affected stationary combustion turbine have accumulated, a report must be submitted for the calendar quarter that includes the 12th-operating month no later than 30 days after the end of that quarter. Thereafter, a report must be submitted for each subsequent calendar quarter, no later than 30 days after the end of the quarter. (79 Fed. Reg. 1508-1509, 1514)

  In each quarterly report, the following information must be included, as applicable: *(i)* Each rolling average CO_2 mass emissions rate for which the last (12th) operating month in a 12-operating month compliance period falls within the calendar quarter. Each average CO_2 mass emissions rate must be calculated. Report the dates (month and year) of the 1st and 12th operating months in each compliance period for which a CO_2 mass emissions rate calculation is calculated. If there are no compliance periods that end in the quarter, include a statement to that effect; *(ii)* If one or more compliance periods end in the quarter, identify each operating month in the calendar quarter with excess CO_2 emissions; *(iii)* The percentage of valid CO_2 mass emission rates in each 12-operating month compliance period (i.e., the total number of valid CO2 mass emission rates in that period divided by the total number of operating hours in that period, multiplied by 100 percent); and *(iv)* The applicable CO_2 emissions standard with which the affected stationary combustion turbine is complying. (79 Fed. Reg. 1508-1509, 1514)

The final quarterly report of each calendar year must contain the following: (i) Net electric output sold to an electric grid over the 4 quarters of the calendar year; and (ii) The potential electric output of the stationary combustion turbine. All electronic reports must be submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA. All applicable reporting requirements must be met and reports submitted as required under subpart G of part 75 of this chapter. (79 Fed. Reg. 1508-1509, 1514)

Applicability Analysis

The first step is to analyze the applicability of the proposed NSPS to the three identical turbines for RBEP. The five applicability criteria and the applicability of each to the turbines are discussed below:

(1) Commenced construction after [DATE OF PUBLICATION IN THE FEDERAL REGISTER];

As shown in Table 2—RBEP Schedule Major Milestones, above, the construction of the new power block is anticipated to begin the first quarter of 2017. The actual construction date will be compared against the future date of publication in the Federal Register.

(2) Has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/hr);

The design heat input for each Mitsubishi turbine is 1492 MMBtu/hr, which is greater than the 250 MMBtu/hr applicability threshold.

(3) Combusts fossil fuel for more than 10.0 percent of the heat input during any 3 consecutive calendar years;

The Mitsubishi turbines are designed to operate on natural gas, a fossil fuel, for 100% of the heat input at all times.

(4) Combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis; and

The Mitsubishi turbines are designed to operate on natural gas, a fossil fuel, for 100% of the heat input at all times.

(5) Was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis.

Each turbine will be constructed for the purpose of supplying one-third or more of its potential electric output to the grid. As calculated below under the thermal efficiency calculations section, a conservative estimate of the annual capacity factor is:

$$\text{Annual capacity factor} = \frac{546.4\ MW_{gross}/3\ \text{turbines} * 6370\ hr}{546.4\ MW_{gross}/3\ \text{turbines} * 8760\ hr} * 100\% = 72.7\% > 33.3\%$$

Each turbine will be constructed for the purpose of supplying more than 219,000 MWh net-electrical output to the grid.

$$\frac{546.4\ MW_{gross}}{3\ \text{turbines}} * \frac{MW_{net}}{0.97\ MW_{gross}} * 6370\ \text{hours} = 1{,}196{,}071\ MWh_{net} > 219{,}000\ MWh_{net}$$

Whether each turbine supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis will be determined by **actual operations once the RBEP is constructed and started up.**

Thermal Efficiency Calculations

The second step is to determine whether the proposed turbines will be able to comply with the proposed emissions standard of **1000 lb CO_2/MWh_{gross}** applicable to turbine engines with a base load rating heat input greater than 850 MMBtu/hr (250 MW), in the event that the RBEP meets the above applicability criteria, including the sales criteria. To that end, the applicant provided thermal efficiency calculations in a letter dated 3/17/14, updating the thermal efficiency calculations presented in letters dated 2/7/14 and 2/14/14, to demonstrate that the RBEP will be able to comply with the proposed emissions standard. The heat rates for the starts and shutdowns for the first nine minutes had been provided in a letter dated 1/11/13.

The annual operating schedule for the thermal efficiency calculations is 6370 hours normal operations, 5 cold starts, 295 combined hot and warm starts, and 300 shutdowns. This schedule includes fewer startups and shutdowns than the permitted annual operating schedule for each turbine of 6370 hours normal operations, 24 cold starts, 600 combined hot and warm starts, and 624 shutdowns. The permitted annual operating schedule represents the maximum operating schedule, and allows the facility the flexibility to operate as necessary to meet the proposed emission standard. **AES has indicated that the RBEP will be operated in compliance with the NSPS, as applicable, by increasing the amount of time RBEP is operated at most efficient heat rates and reducing the number of starts and shutdowns, as necessary.**

The following table reflects the hours for each configuration (1-on-1, 2-on-1, and 3-on-1), and the net plant power electrical output, and net plant heat rates (LHV and HHV) for each of the five load scenarios for each configuration. The most efficient net heat rate will be used for the 2-on-1 configuration, and the average net heat rates will be used for the 1-on-1 and 3-on-1 configurations.

Table 48 - Heat Rates and Electrical Production – Permitted Operating Profile[1]

Turbine Output/Plant Output[2]	Percent	70	80	90	100	100 + Duct Burner	70	80	90	100	100 + Duct Burner	60	70	80	90	100	100 + Duct Burner	Expected Annual Hrs
		1-on-1 Configuration					2-on-1 Configuration					3-on-1 Configuration						
Hours per Configuration per Year	Hrs/Yr	125					5515					730						6370
Net Plant Power Electrical Output	kW	116,977	130,750	144,285	161,150	203,570	241,081	268,702	295,720	329,459	367,913	363,249	367,918	403,656	443,066	492,265		
Net Plant Heat Rate	Btu/kWh-LHV	7,969	7,796	7,669	7,578	7,979	7,733	7,587	7,484	7,413	7,683	7,698	7,681	7,575	7,492	7,440		
Estimated Gross Heat Rate, LHV	Btu/kWh-LHV	7,737	7,569	7,446	7,357	7,747	7,508	7,366	7,266	7,197	7,459	7,474	7,457	7,354	7,274	7,223		
Estimated Net Heat Rate	Btu/kWh-HHV	8,766	8,576	8,436	8,336	8,777	8,506	8,346	8,232	8,154	8,451	8,468	8,449	8,333	8,241	8,184		
Average Net Plant Power Output	kW	151,346					300,575					414,031						
Average Net Heat Rate	Btu/kWh-HHV	8,578										8,335						
Most Efficient Net Heat Rate	Btu/kWh-HHV						8154											
Average Gross Heat Rate	Btu/kWh-HHV	8,328										8,092						
Most Efficient Gross Heat Rate	Btu/kWh-HHV						7917											

1 Operating data from TFLINK 71F Part Load Curve.xls. The thermal efficiency calculations are based on 71 °F, because during the turbine evaluation, the annual average ambient temperature of 71°F was selected. Subsequently, during preliminary engineering, a lower average ambient temperature of 63 °F was identified and used as a basis for the permit application. The effect of using an ambient temperature of 71 °F would tend to slightly increase the plant heat rate and slightly decrease electrical production over the use of a 63 °F temperature.

2 For the 1-on-1 configuration, the headings designate the turbine output. For the 2-on-1 and 3-on-1 configurations, the headings designate the plant output. The 3-on-1 configuration does not include duct firing.

- Startup and Shutdown Rates and Duration
  For the first nine-minutes of a startup and a shutdown, the heat rates are based on a turbine executing a fast start and operating at simple cycle mode heat rates. Thus, the heat rates are the same for cold starts and warm/hot starts. For the balance of the startup and shutdown periods, the heat rates are based on the combined cycle mode heat rate for the 1-on-1 configuration operating at 70 percent load.

  - First 9-Minutes of Startup and 9.5-Minutes for Shutdown
    The applicant provided the following data for startup and shutdown heat rate estimates.

Table 49—RBEP Startup/Shutdown Heat Rate Data[1]

	Duration, min[2]	NOx, lb	CO, lb	VOC, lb	PM_{10}, lb	GT Net MW	Fuel gas, klb
Hot start[3]	9	8.5	142.0	25.6	0.8	2.6	2.3
Shutdown	9.5	11.7	206.0	40.2	1.1	0.5	0.4

1 From MPS preliminary M501DA Fast Start Curve.
2 Duration is the total time for the gas turbine between GT ignition and 70% during start-up and shutdown.

3 Data is stated to be for a hot start. The heat rates for the first 9 minutes, however, will not vary between cold, warm, and hot startups. The reason is that the type of startup (i.e., cold, warm, and hot) is in reference to the shutdown condition (temperature/pressure) of the steam cycle major equipment when initiating the startup; i.e., the heat recovery steam generator, steam turbine, and condenser. The RBEP design is specifically employed such that the steam cycle equipment does not limit the gas turbine startup under any condition. Thus, the RBEP combustion turbines can be started and achieve minimum operating loads (70 percent) within 9 minutes for a cold, warm, or hot start.

To calculate effective heat rates from the above startup/shutdown data:

Start-up (first 9 minutes for cold starts and warm/hot starts)
Heating value of natural gas = 20,650 Btu LHV/lb natural gas

(2300 lb natural gas/start-up) (20,650 Btu LHV/lb natural gas)
(start-up/2.6 net MWh, Table 49) (MWh/1000 kWh) (1.1 HHV/LHV)
= 20,094 Btu /kWh-HHV, net

Shut-down (first 9.5 minutes)
(400 lb natural gas/stop) (20,650 Btu LHV/lb natural gas)
(start-up/0.5 net MWh, Table 49) (MWh/1000 kWh) (1.1 HHV/LHV)
= 18,172 Btu/kWh-HHV, net

- Balance of Startup and Shutdown Periods
  From Table 48 above, the combined cycle mode heat rate for the 1-on-1 configuration operating at 70 percent load is 8,766 Btu/kWh-HHV, net.

  For cold startups, as the total startup period is 90 minutes, the balance is 81 minutes.

For warm/hot startups, as the total startup period is 32.5 minutes, the balance is 23.5 minutes.
For shutdowns, as the total shutdown time is 10 minutes, the balance is 0.5 minutes.

- Annual Hours for Startups and Shutdowns
  - Startup Hours (First 9 minutes)
    (5 cold starts/yr + 295 warm or hot starts/yr)(9 min/startup)(hr/60 min) = 45 hr/yr
  - Startup Hours (Balance of Startup)
    (5 cold starts/yr)(81 min/cold start) (hr/60 min) + (295 warm or hot starts/yr) (23.5 min/warm or hot start)(hr/60 min) = 122.3 hr/yr
  - Shutdown Hours (First 9.5 minutes)
    (300 shutdown/yr)(9.5 min/shutdown)(hr/60 min) = 47.5 hr/yr
  - Shutdown Hours (Balance of Startup)
    (300 shutdown/yr)(0.5 min/shutdown)(hr/60 min) = 2.5 hr/yr
- Summary Table of Startup Rates/Annual Hours and Shutdown Rates/Annual Hours
  The startup rates/annual hours and shutdown rates/annual hours discuss above are summarized in the table below.

Table 50-Startup Rates/Annual Hours and Shutdown Rates/Annual Hours for Permitted Operating Schedule

	Heat Rate, Btu/kWh-HHV, net	Annual Hrs
Startup (First 9 minutes)	20,094	45
Startup (Balance of startup period)	8,766	122.3
Shutdown (First 9.5 minutes)	18,172	47.5
Shutdown (Balance of shutdown period)	8,766	2.5

- Overall Net Heat Rate (without degradation)
  Overall Average Net Heat Rate (without degradation) =
  {(Avg annual heat rate * annual hrs *for 1-on-1*) + (most efficient annual heat rate * annual hrs *for 2-on-1*) + (Avg annual heat rate * annual hrs *for 3-on-1*) + (Startup heat rate $_{\text{9 MINUTES}}$ * annual hours $_{\text{9 MINUTES}}$) + (Startup heat rate $_{\text{BALANCE STARTUP}}$ * annual hours $_{\text{BALANCE STARTUP}}$) + (Shutdown heat rate $_{\text{9 MINUTES}}$ * annual hours $_{\text{9 MINUTES}}$) + (Shutdown heat rate $_{\text{BALANCE STARTUP}}$ * annual hours $_{\text{BALANCE STARTUP}}$)} / Total annual hrs

  {(8578 Btu/kWh-HHV * 125 hrs *for 1-on-1*) + (8154 Btu/kWh-HHV * 5515 hrs *for 2-on-1*) + (8335 Btu/kWh-HHV * 730 hrs *for 3-on-1*) + (20,094 Btu/kWh-HHV * 45 hr) + (8766 Btu/kWh-HHV * 122.3 hr) + (18,172 Btu/kWh-HHV * 47.5 hr) + (8766 Btu/kWh-HHV * 2.5 hr)} / (125 + 5515 + 730 + 45 + 122.3 + 47.5 + 2.5 hr)
  = 8347.5 Btu/kWh-HHV, net

The average annual heat rates and corresponding annual hours for 1-on-1, 2-on-1, and 3-on-1 states are from Table 48. The startup and shutdown rates and corresponding annual hours are from Table 50.

- GHG Efficiency (without degradation)

  Net

  GHG Efficiency, net (without degradation) = [Overall Net Heat Rate] * [CO_2] =

  [(8347.5 Btu/kWh-HHV, net)(1000 kWh/MWh)(MMBtu/1,000,000 Btu)] *

  [(53.02 kg CO_2/MMBtu-HHV)(2.2046 lb/kg)]

  = 975.2 lb CO_2 /MWh-HHV, net

  Gross

  GHG Efficiency, gross (without degradation) =

  (975.2 lb CO_2 /MWh-HHV, net) (0.97 MWh, gross / MWh, net)
  = 945.9 lb CO_2 /MWh-HHV, gross

- GHG Efficiency, net (with degradation)

  AES expects that, after commissioning, RBEP will experience a permanent 3 percent performance degradation. Between major maintenance events, AES assumes an additional 5 percent performance degradation can occur, which can be recovered through the development and implementation of an inspection and maintenance of plant equipment.

  Net

  GHG Efficiency, net (with degradation) = (975.2 lb CO_2 /MWh-HHV, net) (1 + 0.03)
  = 1004.5 lb CO_2 /MWh-HHV, net

  Gross

  GHG Efficiency, gross (with degradation) = (945.9 lb CO_2 /MWh-HHV, gross) (1 + 0.03)
  = 974.3 lb CO_2 /MWh-HHV, gross

  ***__**Compliance Demonstration**__

  The 974.3 lb CO_2 /MWh-HHV$_{gross}$ demonstrates that RBEP can meet the 1000 lb CO_2/MWh$_{gross}$ standard.

- Annual Capacity Factor
  Annual Capacity Factor =

  $$\frac{\text{Annual amount of electricity produced}}{\text{Annual amount of electricity at maximum capacity during all hours of the year}}$$

  For annual amount of electricity produced, assume RBEP operates at the maximum electrical output of 546.4 MW gross for 6370 hr/yr. (Startup and shutdown hours are not included because the majority of the electrical output will occur during normal operating hours.)

  For annual amount of electricity at maximum capacity during all hours of the year, assume RBEP operates at 546.4 MW gross for 8760 hours.

  $$\text{Annual capacity factor} = \frac{(546.4\ MW_{gross} / 3\ \text{turbines}) * 6370\ hr}{(546.4\ MW_{gross} / 3\ \text{turbines}) * 8760\ hr} * 100\% = 72.7\%$$

  The 72.7 percent capacity factor calculated here is conservative because the turbines will not actually be operating at the maximum electrical load of 546.4 MW gross for all 6370 hr/yr.

  Pg. 2-40 of the AFC indicates the expected annual capacity factor is between 15 and 25 percent.

- Condition E193.7
  Condition E193.7 implements the NSPS and the Rule 1714 BACT requirements.

  The condition includes a formula for the calculation of greenhouse gases (tons CO_2):
  GHG = 61.37 * FF

  Using fuel consumption, where FF is the monthly fuel usage in millions standard cubic feet:

  GHG (CO_2) (tons/month) = {(53.02 kg CO_2/MMBtu) * {(2.2046 lb/kg)(ton/2000 lb) (1050 MMBtu/MMcf) * FF } = 61.37 * FF

  GHG (CO_2) emissions are limited to 1000 lbs per gross megawatt-hour or the applicable limit which is published in the final EPA rule, if RBEP meets the applicability criteria.

40 CFR 60 Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

§60.40Da(a)(1) & (2)—Except as specified in paragraph (e), the affected facility to which this subpart applies is each electric utility steam generating unit that is capable of combusting more than 73 MW (250 MMBtu/hr) heat input; and for which construction, modification, or reconstruction is commenced after September 18, 1978. Thus each heat recovery steam generator with associated duct burner, rated at 507 MMBtu/hr, is subject to this subpart, unless an applicability exemption applies.

§60.40Da(e)—Applicability of this subpart to an electric utility combined cycle gas turbine other than an integrated gasification combined cycle electric utility steam generating unit is specified in (e)(1) through (3).

> *(e)(1)*—Affected facilities (i.e. heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (i.e. heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK.

Because each combustion turbine and the associated heat recovery steam generator with duct burner meet the applicability requirements of subpart KKKK, the heat recovery steam generator with duct burner is not subject to this subpart.

<u>40 CFR 60 Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units</u>

§60.40b(a)—This subpart applies to each steam generating unit that commences construction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 MMBtu/hr). Thus each heat recovery steam generator with associated duct burner, rated at 507 MMBtu/hr, is subject to this subpart, unless an applicability exemption applies.

§60.40b(i)—Affected facilities (i.e., heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK are not subject to this subpart.

Because each combustion turbine and the associated heat recovery steam generator with duct burner meet the applicability requirements of subpart KKKK, the heat recovery steam generator with duct burner is not subject to this subpart.

<u>40 CFR Part 60 Subpart GG--NSPS for Stationary Gas Turbines</u>

Subpart GG establishes requirements for stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on lower heating value, which commences construction, modification, or reconstruction after October 3, 1997 and are not subject to subpart KKKK. Subpart KKKK is applicable to stationary combustion turbines with a heat input greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on higher heating value, which commenced construction, modification or reconstruction after February 18, 2005. The proposed CTGs are subject to the requirements of 40 CFR Subpart KKKK (see below) and thus are exempt from the requirements of this subpart per §60.4305(b).

<u>40 CFR Part 60 Subpart KKKK-- NSPS for Stationary Gas Turbines</u>

Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

In addition, the proposed Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (January 8, 2014) analyzed above is still in subject to public comments and final action by EPA, but may become part of Subpart KKKK or create a new subpart TTTT. Therefore, its compliance has been evaluated above, in case it becomes final and subject to this project in its final form.

§60.4305

(a)—This subpart is applicable to stationary combustion turbines with a heat input greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on the higher heating value of the fuel, which commenced construction, modification or reconstruction after February 18, 2005. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to the turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining the peak heat input. However, this part does apply to emissions from any associated HRSG and duct burners.

(b)—Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc.

<u>Analysis</u>: This subpart is applicable to the combustion turbines, which are rated at 1492 MMBtu/hr each. The emissions from each turbine are combined with the emissions from the associated HRSG and duct burner, which are then controlled by the associated CO catalyst and SCR.

§60.4320(a)—Gas turbines are required to meet the NOx emission limits specified in Table 1 of this subpart. Table 1 provides NOx emission standards based on combustion turbine type and heat input at peak rate. For a new natural-gas fired turbine with a heat input > 50 MMBtu/hr and ≤ 850 MMBtu/hr, the NOx emission limit is 25 ppmv @ 15% O_2.

<u>Analysis</u>: Since the CTGs with associated duct burners will meet the BACT limit of 2.0 ppmv @ 15% O_2, compliance with this section is expected. Accordingly, an emissions limit of 25 ppmv NOx is included for the CTGs and the associated duct burners pursuant to this subpart.

§60.4330(a)(2)—Gas turbines are required to comply with (a)(1), (a)(2), or (a)(3) to meet the sulfur dioxide emission limit. Paragraph (a)(1) specifies the turbine exhaust gas shall not contain SO_2 in excess of 0.90 lbs/MWh gross output. Paragraph (a)(2) specifies the fuel shall not contain total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input for units located in continental areas.

> <u>*Analysis:*</u> The 0.90 lbs/MWh is a stack limit that requires annual source testing for verification pursuant to §60.4415. The 0.06 lb/MMBtu is a fuel based limit which will require fuel monitoring (§60.4360) or fuel supplier data (§60.4365). As discussed in the analysis for §60.4365 below, the CTGs are expected to be in compliance with the 0.06 lb/MMBtu limit. Accordingly, an emissions limit of 0.06 lb/MMBtu SO_2 is included for the CTGs and the associated duct burners pursuant to this subpart.

§60.4340—To demonstrate compliance for NOx if water or steam injection is not used, an alternative to the required annual performance testing is the installation and operation of a continuous monitoring system consisting of a certified NOx and O_2 CEMS.

> <u>*Analysis:*</u> For this project, monitoring of the emissions from each combustion turbine and associated duct burner will be achieved with a CEMS certified in accordance with Rule 2012.

§60.4360—The total sulfur content of the fuel being fired in the turbine must be monitored using total sulfur methods described in §60.4415, except as provided in §60.4365, discussed below.

§60.4365—An election may be made not to monitor the total sulfur content of the fuel combusted in the turbine pursuant to the monitoring requirements in §60.4370, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input for units located in continental areas. Two sources of information may be used to make the required demonstration: (1) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for natural gas use in continental areas is **20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input** for continental areas, or (2) Representative fuel sampling data which show the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu).

> <u>*Analysis:*</u>
> Rule 431.1 limits pipeline natural gas to 16 ppmv sulfur limit (calculated as H_2S) specified in this rule. The 16 ppmv sulfur is equivalent to 1.0 grain/100 SCF (0.0626285 grain/100 SCF per 1 ppm), which is significantly less than 20 grains/100 SCF.
>
> Further, Southern California Gas Company, Tariff Rule No. 30—Transportation of Customer-Owned Gas, allows up to 0.75 gr. S/100 scf total sulfur.
>
> To convert 0.75 gr S/100 scf to units of lb SO_2/MMBtu--
> (0.75 gr S/100 ft^3) (1 lb/7000 gr) (ft^3/913 Btu [LHV])(1 E+06 Btu/MMBtu)
> (64 lb SO_x/32 lb S) = 0.0023 lb SO_2/MMBtu < 0.06 lb SO_2/MMBtu limit

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

This regulation applies to gas turbines located at major sources of HAP emissions. The applicability of federal requirements governing HAPs is dependent on whether a facility is a major source or area source for HAPs. A "major source" means "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants." An "area source" means "any stationary source of hazardous air pollutants that is not a major source."

From Table 24 above, the single highest HAP emissions, formaldehyde, from the facility is 5.29 tpy (3 *1.76 tpy/turbine & duct burner), which is less than 10 tpy. The total combined HAPs from all sources is 9.93 tpy (3 * 3.31 tpy/turbine & duct burner), which is less than 25 tpy. HAPS emissions are limited by condition A63.1, which limits annual operations to 6835 hours in any calendar year (including startups and shutdowns).

Therefore, the RBEP is an area source for HAPS, not a major source. The requirements of this regulation do **not** apply.

40 CFR Part 64 – Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) rule, 40 CFR Part 64, specifies the monitoring, reporting, and recordkeeping criteria that is required to be conducted by Title V facilities to demonstrate ongoing compliance with emission limitations and standards. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits.

In general, CAM applies to emissions units that meet all of the following conditions:

- the unit is located at a major source for which a Title V permit is required: and
- the unit is subject to an emission limitation or standard; and
- the unit uses a control device to achieve compliance with a federally enforceable limit or standard; and
- the unit has potential pre-control emissions (Title V renewal) or post-control emissions (initial Title V or revision) of at least 100% of the major source amount; and
- the unit is not otherwise exempt from CAM.

The turbines are located at a major source for which a Title V permit is required. The NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR and CO catalyst to meet BACT limits. For each turbine, the post-control NOx, CO, and VOC emissions are higher than the major source thresholds. Specifically, the NOx emissions are 41.3 tpy (commissioning year), which is higher than the 10 tpy major source threshold. The CO emissions (commissioning year) are

98.8 tpy, which is higher than the 50 tpy threshold. The VOC emissions (commissioning year) are 32.2 tpy, which is higher than the 10 tpy threshold. Thus, the CAM regulations are applicable.

For each turbine, a continuous emission monitoring system (CEMS) will be installed for NOx and for CO. The NOx CEMS will be certified in accordance with Rule 2012 requirements, and the CO CEMS will be certified in accordance with Rule 218 requirements. 40 CFR Part 64.2(b)(1)(vi) provides that the requirements of this part shall not apply to an emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1. §64.1 defines "continuous compliance determination method" to mean "a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit." Since the NOx and CO CEMS qualify as continuous compliance determination methods, the CEMS provide an exemption from this subpart for NOx and CO.

This subpart also applies to the VOC emissions because the VOC BACT limit is achieved with the assistance of the oxidation catalyst. The oxidation catalyst is primarily installed to control CO emissions, but also controls VOC emissions to a minor degree. The CO catalyst is located at the outlet of the turbine and designed to provide the required control efficiency at the expected turbine exhaust temperature range. There are no operational requirements for the CO catalyst. To assure that the catalyst is not exhausted, each turbine is required to be source tested every three years for VOC pursuant to condition D29.2.

<u>40 CFR Part 68—Chemical Accident Prevention Programs</u>

§68.1—This part sets forth the list of regulated substances and thresholds and the requirements for owners or operators of stationary sources concerning the prevention of accidental releases.

§68.10(a)—An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process shall comply with the requirements of this part.

§68.130(a)—Regulated toxic and flammable substances are listed with the associated threshold quantities in Tables 1, 2, 3, and 4 to §68.130. Table 1 to §68.130—List of Regulated Toxic Substances and Threshold Quantities for Accidental Release Prevention [Alphabetical Order—77 Substances] listed "ammonia (anhydrous)" with a threshold quantity of 10,000 lbs, and "ammonia (conc 20% or greater)" with a threshold quantity of 20,000 lbs.

Because the new ammonia tank (Device D87) installed with the RBEP project will contain 19% ammonia, not anhydrous ammonia or ammonia with a 20% or greater concentration, Part 68 is not applicable. Therefore, facility condition F24.1, which requires compliance with the accidental release prevention requirements pursuant to 40 CFR Part 68, is not applicable to the new tank.

Facility condition F24.1 is applicable to the two existing ammonia tanks in Section D, Devices D18 and D83, because they are permitted to use 29% aqueous ammonia. Condition F24.1 will be removed from the facility permit after D18 and D83 are removed from the facility.

Regulation XXXI—Acid Rain Permit Program (40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 - Acid Rain Provisions)

Acid Rain provisions are designed to control SO_2 and NOx emissions that could form acid rain from fossil fuel fired combustion devices in the electricity generating industry. Facilities are required to cover SO_2 emissions with "SO_2 allowances" or purchase of SO_2 offsets on the open market. The facility is also required to monitor SO_2 emissions through use of fuel gas meters and gas constituent analysis (use of emission factors is also acceptable in certain cases), or with the use of exhaust gas CEMS. The RBEP facility will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with natural gas default sulfur data as allowed by the Acid Rain regulations (Appendix D to 40 CFR Part 75). If additional SO_2 credits are needed, RBEP will obtain the credits from the SO_2 trading market. Based on the above, compliance with this rule is expected.

STATE REGULATIONS

California Environmental Quality Act (CEQA)

CEQA applies to projects undertaken by a public agency, funded by a public agency, or requires an issuance of a permit by a public agency. A "project" means the whole of an action that has a potential for resulting in physical change to the environment, and is an activity that may be subject to several discretionary approvals by government agencies. A project is exempt from CEQA if by statute, if considered ministerial or categorical, where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment.

The RBEP project is subject to CEQA because there are no applicable exemptions. The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. Accordingly, AES filed an AFC (12-AFC-03) for the project on November 20, 2012. The CEC's 12-month licensing process is a certified regulatory program under CEQA. Thus, the CEC is the lead agency.

California Code of Regulations (CCR), Chapter 11—Greenhouse Gases Emission Performance Standard, Article 1—Provisions Applicable to Powerplants 10 MW and Larger (SB 1368)

The California Emissions Performance Standard (EPS) of **1100 lbs CO_2/MW-hour$_{net}$** of electricity applies to local publicly owned electric utilities. California regulations stipulate that no local publicly owned electric utility shall enter into a covered procurement if greenhouse gases emissions from the power plant(s) subject to the covered procurement exceed the EPS. A "covered procurement" is defined in §2901(d) as "(1) A new ownership investment in a base load generation power plant, or (2) A new or renewed contract commitment, including a lease, for the procurement of electricity with a term of five years or greater by a local publicly owned electric utility with: (A) a base load generation power plant, unless the power plant is deemed compliant, or (B) any generating units added to a deemed-compliant base load generation power plant that combined result in an increase of 50 MW or more to the power plant's rated capacity."

AES will attempt to enter into a covered procurement for RBEP with a local publicly owned electric utility. If AES is successful in securing a covered procurement for RBEP with a local publicly owned electric utility, then that utility is required to submit a compliance filing to the California Energy Commission. The Commission then issues a decision on whether the covered procurement complies with the EPS.

The applicable sections of the regulation are reproduced below, with the rule analysis following.

§ 2900. Scope.
This Article applies to covered procurements entered into by local publicly owned electric utilities. The greenhouse gases emission performance standard established in section 2902(a) applies to any generation, regardless of capacity, supplied under a covered procurement. The provisions requiring local publicly owned electric utilities to report covered procurements, including Sections 2908, 2909, and 2910, apply only to covered procurements involving powerplants 10 MW and larger.

§ 2901. Definitions.

(a) "Annualized plant capacity factor" means the ratio of the annual amount of electricity produced, measured in kilowatt hours, divided by the annual amount of electricity the powerplant could have produced if it had been operated at its maximum permitted capacity during all hours of the year, expressed in kilowatt hours.

(b) "Baseload generation" means electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.

(c) "Combined-cycle natural gas" means a powerplant that employs a combination of one or more natural gas turbines and one or more steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines.

(k) "Permitted capacity" means the rated capacity of the powerplant unless the maximum output allowed under the operating permit is the effective constraint on the maximum output of the powerplant.

(l) "Powerplant" means a facility for the generation of electricity, and is:
  (1) a single generating unit; or
  (2) multiple generating units that meet the following conditions:
    (A) the generating units are co-located;

(B) each generating unit utilizes the same fuel and generation technology; and
(C) one or more of the generating units are operationally dependent on another.

(m) "Rated capacity" means the powerplant's maximum rated output. For combustion or steam generating units, rated capacity means generating capacity and shall be calculated pursuant to Section 2003.

(Pursuant to § 2003(a), the "generating capacity" of an electric generating facility means the maximum gross rating of the plant's turbine generator(s), in megawatts ("MW"), minus the minimum auxiliary load.)

§ 2902. Greenhouse Gases Emission Performance Standard.

(a) The greenhouse gases emission performance standard (EPS) applicable to this chapter is 1100 pounds (0.5 metric tons) of carbon dioxide (CO_2) per megawatt hour (MWh) of electricity.

(b) Unless otherwise specified in this Article, no local publicly owned electric utility shall enter into a covered procurement if greenhouse gases emissions from the powerplant(s) subject to the covered procurement exceed the EPS.

§ 2903. Compliance with the Emission Performance Standard.

(a) Except as provided in Subsection (b), a powerplant's compliance with the EPS shall be determined by dividing the powerplant's annual average carbon dioxide emissions in pounds by the powerplant's annual average net electricity production in MWh. This determination shall be based on capacity factors, heat rates, and corresponding emissions rates that reflect the expected operations of the powerplant and not on full load heat rates.

§ 2905. Annual Average Electricity Production.

(a) Except as provided in Subsection (b), a powerplant's annual average electricity production in MWh shall be the sum of the net electricity available for all of the following: use onsite or at a host site in a commercial or industrial process or for sale or transmission from the powerplant.

Applicability Analysis

The first step is to analyze the applicability of the state EPS standard to the three identical turbines for RBEP. § 2900 provides that local publicly owned electric facilities shall make the determination regarding compliance with the EPS prior into entering into a covered procurement. § 2901(b) defines "baseload generation" to mean "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent."

As part of the thermal efficiency calculations to show compliance with the proposed NSPS for New Stationary Sources: Electric Utility Generating Units, the annual capacity factor for the permitted schedule is conservatively calculated above to be 72.7%. The annual capacity factor for the expected schedule is conservatively calculated as part of the thermal efficiency calculations below to be 28%.

Thermal Efficiency Calculations

The second step is to determine whether the proposed turbines will be able to comply with the emissions standard of **1100 lb CO_2/MWh_{net}** in the event the RBEP meets the above applicability criteria. § 2903(a) provides that a power plant's compliance with the EPS shall be based on "expected" operations.

Accordingly, the applicant provided thermal efficiency calculations for the expected annual operating profile in letters dated 1/11/13, 3/15/13, 2/7/14, and 2/14/14. The following table reflects the hours for each configuration (1-on-1, 2-on-1, and 3-on-1), the net plant power electrical output and the net heat rates for each of the five load scenarios for each configuration. The expected annual operating schedule is 2455 hours normal operations, 24 cold starts, 150 warm starts, and 450 hot starts. The average heat rates will be used for all three configurations.

Table 51 - Heat Rates and Electrical Production -- Expected Operating Profile at an Ambient Temperature of 71 Deg F[1]

Turbine Output/Plant Output[2]	Percent	70	80	90	100	100 + Duct Burner	70	80	90	100	100 + Duct Burner	60	70	80	90	100	100 + Duct Burner	Expected Annual Hrs
		1-on-1 Configuration					2-on-1 Configuration					3-on-1 Configuration						
Hours per Configuration per Year	Hrs/Yr	125					1600					730						2455
Net Plant Power Electrical Output	kW	116,977	130,750	144,285	161,150	203,570	241,081	268,702	295,720	329,459	367,913	363,249	367,918	403,656	443,066	492,265		
Net Plant Heat Rate	Btu/kWh-LHV	7,969	7,796	7,669	7,578	7,979	7,733	7,587	7,484	7,413	7,683	7,698	7,681	7,575	7,492	7,440		
Estimated Gross Heat Rate, LHV	Btu/kWh-LHV	7,737	7,569	7,446	7,357	7,747	7,508	7,366	7,266	7,197	7,459	7,474	7,457	7,354	7,274	7,223		
Estimated Net Heat Rate	Btu/kWh-HHV	8,766	8,576	8,436	8,336	8,777	8,506	8,346	8,232	8,154	8,451	8,468	8,449	8,333	8,241	8,184		
Average Net Plant Power Output	kW	151,346					300,575					414,031						
Average Net Heat Rate	Btu/kWh-HHV	8,578					8,338					8,335						
Average Gross Heat Rate	Btu/kWh-HHV	8,328					8,095					8,092						

1 Operating data from TFLINK 71F Part Load Curve.xls. The thermal efficiency calculations are based on 71 °F, because during the turbine evaluation, the annual average ambient temperature of 71 °F was selected. Subsequently, during preliminary engineering, a lower average ambient temperature of 63 °F was identified and used as a basis for the permit application. The effect of using an ambient temperature of 71 °F would tend to slightly increase the plant heat rate and slightly decrease electrical production over the use of a 63 °F temperature.

2 For the 1-on-1 configuration, the headings designate the turbine output. For the 2-on-1 and 3-on-1 configurations, the headings designate the plant output. The 3-on-1 configuration does not include duct firing.

The thermal efficiency calculation methodology below is the same as that used to show compliance with the proposed NSPS for New Stationary Sources: Electric Utility Generating Units above.

- Startup and Shutdown Rates and Duration
  Same as for NSPS thermal efficiency calculations.

- Annual Hours for Startups and Shutdowns
  - Startup Hours (First 9 minutes)
    (24 cold starts/yr + 150 warm starts/yr + 450 hot starts/yr)(9 min/startup)(hr/60 min) = 93.6 hr/yr
  - Startup Hours (Balance of Startup)
    (24 cold starts/yr)(81 min/cold start) (hr/60 min) + (150 warm starts/yr + 450 hot starts/yr) (23.5 min/warm or hot start)(hr/60 min) = 267.4 hr/yr
  - Shutdown Hours (First 9.5 minutes)
    (24 + 150 + 450 shutdown/yr)(9.5 min/shutdown)(hr/60 min) = 98.8 hr/yr
  - Shutdown Hours (Balance of Startup)
    (24 + 150 + 450 shutdown/yr)(0.5 min/shutdown)(hr/60 min) = 5.2 hr/yr

- Summary Table of Startup Rates/Annual Hours and Shutdown Rates/Annual Hours
  The startup rates/annual hours and shutdown rates/annual hours discuss above are summarized in the table below.

Table 52-Startup Rates/Annual Hours and Shutdown Rates/Annual Hours for Expected Operating Schedule

	Heat Rate, Btu/kWh-HHV, net	Annual Hrs
Startup (First 9 minutes)	20,094	93.6
Startup (Balance of startup period)	8,766	267.4
Shutdown (First 9.5 minutes)	18,172	98.8
Shutdown (Balance of shutdown period)	8,766	5.2

- Overall Average Net Heat Rate (without degradation)
  Overall Average Net Heat Rate (without degradation) =

  {(Avg annual heat rate * annual hrs *for 1-on-1*) + (Avg annual heat rate * annual hrs *for 2-on-1*) + (Avg annual heat rate * annual hrs *for 3-on-1*) + (Startup heat rate $_{\text{9 MINUTES}}$ * annual hours $_{\text{9 MINUTES}}$) + (Startup heat rate $_{\text{BALANCE STARTUP}}$ * annual hours $_{\text{BALANCE STARTUP}}$) + (Shutdown heat rate $_{\text{9 MINUTES}}$ * annual hours $_{\text{9 MINUTES}}$) + (Shutdown heat rate $_{\text{BALANCE STARTUP}}$ * annual hours $_{\text{BALANCE STARTUP}}$)} / Total annual hrs

  {(8578 Btu/kWh-HHV * 125 hrs *for 1-on-1*) + (8338 Btu/kWh-HHV * 1600 hrs *for 2-on-1*) + (8335 Btu/kWh-HHV * 730 hrs *for 3-on-1*) + (20,094 Btu/kWh-HHV * 93.6 hr) + (8766 Btu/kWh-HHV * 267.4 hr) + (18,172 Btu/kWh-HHV * 98.8 hr) + (8766 Btu/kWh-HHV * 5.2 hr)} / (125 + 1600 + 730 + 93.6 + 267.4 + 98.8 + 5.2 hr)
  = 9097.06 Btu/kWh-HHV, net

The average annual heat rates and corresponding annual hours for 1-on-1, 2-on-1, and 3-on-1 states are from Table 51. The startup and shutdown rates and corresponding annual hours are from Table 52.

- GHG Efficiency, net (without degradation)
  GHG Efficiency, net (without degradation) =

  [Overall Average Net Heat Rate] * [CO_2] =

  [(9097.06 Btu/kWh-HHV, net)(1000 kWh/MWh)(MMBtu/1,000,000 Btu)] *

  [(53.02 kg CO_2/MMBtu-HHV)(2.2046 lb/kg)]

  = 1063.3 lb CO_2 /MWh-HHV, net

- GHG Efficiency, net (with degradation)
  The applicant has requested a maximum degradation rate of 8%.

  GHG Efficiency, net (with degradation) = (1063.3 lb CO_2 /MWh-HHV, net) (1 + 0.08)
  = 1148.4 lb CO_2 /MWh-HHV, net

  ***Compliance Demonstration
  The 1063.3 lb CO_2 /MWh-HHV$_{net}$ (exclusive of degradation) demonstrates that RBEP can meet the 1000 lb CO_2/MWh$_{net}$ standard.

- Capacity Factor
  Capacity Factor =

  $$\frac{\text{Annual amount of electricity produced}}{\text{Annual amount of electricity at maximum permitted capacity during all hours of the year}}$$

  For annual amount of electricity produced, assume RBEP operates at the maximum electrical output of 546.4 MW gross for 2455 hr/yr. (Startup and shutdown hours are not included because the majority of the electrical output will occur during normal operating hours.)

  For annual amount of electricity at maximum capacity during all hours of the year, assume RBEP operates at 546.4 MW gross for 8760 hours.

  $$\text{Annual capacity factor} = \frac{(546.4\ MW_{gross} / 3\ \text{turbines}) * 2455\ hr}{(546.4\ MW_{gross} / 3\ \text{turbines}) * 8760\ hr} * 100\% = 28\%$$

The 28 percent capacity factor calculated here is conservative because the turbines will not actually be operating at the maximum electrical load of 546.4 MW gross for all 2455 hr/yr.

Pg. 2-40 of the AFC indicates the expected annual capacity factor is between 15 and 25 percent.

- Condition E193.6
  Condition E193.6 implements the California EPS and the Rule 1714 BACT requirements.

  As with Condition E193.7 discussed above, the condition includes a formula for the calculation of greenhouse gases (tons CO_2):

  GHG = 61.37 * FF.

  GHG (CO_2) emissions are limited to 572,378 tons per year per turbine (Table 25). The calendar average GHG emissions is limited to 1063.3 lbs per net megawatt-hours (1148.4 lbs per new megawatt-hours inclusive of equipment degradation).

RECOMMENDATION

Based on the above analysis, it is recommended that the FDOC be published following the conclusion of the required CEC, EPA, and public review and comment periods and subject to any comments received during these periods. After the CEC issues the Final Commission Decision, the Permits to Construct may be issued.