DOCKETED

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Project Title:	Canyon Power Plant - Compliance
TN #:	203434
Document Title:	Canyon Power Plant Draft SCAQMD Permit
Description:	N/A
Filer:	Jerry Salamy
Organization:	CH2M HILL
Submitter Role:	Applicant Consultant
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South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

December 10, 2014

Mr. Dale Rundquist
Compliance Project Manager
California Energy Commission
1516 Ninth Street, MS-2000
Sacramento, CA 95814

SUBJECT: Canyon Power Plant (CPP)--Proposed Increase in Operating Schedule
Facility Location: 3071 E. Miraloma Avenue, Anaheim, CA 92806

Dear Mr. Rundquist:

The South Coast Air Quality Management District (SCAQMD) has received permit applications for the subject project. The applicant is proposing to revise the permits to operate to increase the operating schedule limits for the four identical natural-gas fired electric generating gas turbines at this 200 megawatt (MW) power plant. Effective January 1, 2015, the California Independent System Operator (CAISO) Flexible Resource Adequacy Criteria and Must Offer Obligation (FRAC-MOO) will require the Canyon Power Plant to provide a significant amount of flexible generation capacity to serve as backup for solar and wind generation to maintain system reliability.

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 proposed Title V permit and engineering evaluation. 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 and 3006 – Title V Public Participation.

We intend to issue the revised permits to operate upon completion of the 30-day public comment and review period and after all pertinent comments have been considered, and 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 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 me at (909) 396-2643 /alee@aqmd.gov.

Sincerely,

Andrew Lee

Andrew Lee, P.E.
Senior Manager
Energy/Public Services/Waste Mgmt/Terminals-Permitting
Engineering and Compliance

AYL:CDT:JTY:VL

Enclosures: Public Notice
Draft Facility Permit
Engineering Evaluation

cc: Manny Robledo, w/o attachment

MAILED
12/11/14

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Air Quality Management District
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**NOTICE OF INTENT TO ISSUE PERMITS
PURSUANT TO SCAQMD RULES 212 AND 3006**

This notice is to inform you that the South Coast Air Quality Management District (SCAQMD) has received permit applications from the Canyon Power Plant to revise the permits to operate to increase the operating schedule limits for the four identical natural-gas fired electric generating gas turbines. Effective January 1, 2015, the California Independent System Operator (CAISO) Flexible Resource Adequacy Criteria and Must Offer Obligation (FRAC-MOO) will require the Canyon Power Plant to provide a significant amount of flexible generation capacity to serve as backup for solar and wind generation to maintain system reliability. After detailed review and evaluation of the applications, 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 the revised Permits to Operate and to revise the Title V permit for this facility upon the completion of review by the EPA and the California Energy Commission (CEC). 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) and Rule 212(g) because the increased emissions from the gas turbines exceed the public notice thresholds for these rules. Public notification is required by SCAQMD Rule 3006(a) because there will be a significant revision to the facility's existing Title V air permit.

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

FACILITY: Canyon Power Plant
Facility ID No. 153992
3071 E. Miraloma Avenue
Anaheim, CA 92806

CONTACT: Manny Robledo
Electric Operations Manager
Anaheim Public Utilities Dept.
201 S. Anaheim Blvd, M.S. #802
Anaheim, CA 92805

SCAQMD APPLICATION NUMBERS

Application Number	Equipment Description
555828	GE LM6000PC Sprint Gas Turbine No. 1
555829	GE LM6000PC Sprint Gas Turbine No. 2
555830	GE LM6000PC Sprint Gas Turbine No. 3
555831	GE LM6000PC Sprint Gas Turbine No. 4
555832	Internal Combustion Engine, Emergency
555827	Title V/RECLAIM Significant Permit Revision

PROJECT DESCRIPTION

The Canyon Power Plant is a power plant with the capability of generating a total of 200 megawatts (MW) of electrical power consisting of four simple cycle GE LM6000PC Sprint gas turbines with associated air pollution control systems, one 1141 brake horsepower diesel fueled emergency black start engine, and miscellaneous equipment. The applications propose to increase the operating schedule limits for the four turbines because the CAISO will require the facility to provide a significant amount of flexible generation capacity to serve as backup for solar and wind generation to maintain system reliability. The applications also propose to reduce the operating schedule limit for the black start engine.

EMISSIONS

During normal operation, the increase in total potential maximum daily, monthly, and annual emissions of criteria pollutants resulting from the increase in operating schedule for the turbines is estimated not to exceed the emission levels listed in the table below. In addition, the facility generates 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).

Pollutant	Max Potential Emissions Increase (Tons)		
	Daily	Monthly	Annual
Nitrogen Oxides (NOx)	0.108	3.25	15.36
Carbon Monoxide (CO)	0.109	3.28	20.32
Volatile Organic Compounds (VOC)	0.019	0.57	4.12
Particulate Matter (diameter less than 10 microns, PM_{10} or diameter less than 2.5 microns, $PM_{2.5}$)	0.016	0.48	2.46
Sulfur Oxides (SOx)	0.005	0.15	1.12
Carbon Dioxide equivalent ($CO_{2equivalent}$)	530.09	15,902.70	190,975.84

The applicant is required to provide emission offsets for the increases in VOC and PM_{10} emissions. The required emission offsets have been provided in the form of emission reduction credits (ERCs). The South Coast Air Basin meets and is in attainment with ambient air quality standards for CO, so no CO offsets are required. The applicant is required to provide emission offsets for the increase in NOx emissions. Offsets have been provided in the form of RECLAIM Trading Credits (RTCs) purchased through the Regional Clean Air Incentive's Market (RECLAIM).

As a result of burning natural gas in the gas turbines, emissions from the turbines 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 on each turbine based on the proposed operating schedule. 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) from each gas turbine 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		Non-Cancer Hazard Index	
Equipment	Resident	Worker	Chronic	Acute
Gas Turbine No. 1	0.0426E-06	0.0271E-06	3.18E-04	1.54E-03
Gas Turbine No. 2	0.0448E-06	0.0262E-06	3.07E-04	1.49E-03
Gas Turbine No. 3	0.0470E-06	0.0258E-06	3.02E-04	1.46E-03
Gas Turbine No. 4	0.0493E-06	0.0260E-06	3.04E-04	1.47E-03
Rule 1401 Limit	1.0E-06		1.0	

Based on the result of our detailed analysis and evaluation, the SCAQMD has determined that the proposed project complies with all applicable federal, state and SCAQMD air quality Rules and Regulations and, therefore, SCAQMD intends to issue the Permits to Operate to increase the operating schedule limits for the turbines. In addition, prior to issuance of a final permit, SCAQMD is providing an opportunity for a 30-day public comment period, and review periods for the EPA and the CEC. SCAQMD will consider issuance of the final permit only after all pertinent public, EPA and CEC comments, if any, have been received and considered.

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 January 2, 2015.** This form is available on the SCAQMD website at http://www.aqmd.gov/docs/default-source/grants/500-g-form.pdf?sfvrsn=2, 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 Anaheim Central Library, 500 W. Broadway, Anaheim, CA 92805. 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 Operate can also be viewed at http://www3.aqmd.gov/webappl/publicnotices2/Search.aspx. 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 January 16, 2015.** 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
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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 1: POWER GENERATION					
System 1: GAS TURBINE					

* (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.

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Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
Process 1: POWER GENERATION					
GAS TURBINE, NO. 1, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: GENERATOR, 50.95 MW	D1	C3	NOX: MAJOR SOURCE**	**CO**: 4 PPMV NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]; **CO**: 2000 PPMV NATURAL GAS (5) [**RULE 407, 4-2-1982**]; **NOX**: 2.5 PPMV NATURAL GAS (4) [**RULE 2005, 6-3-2011**]; **NOX**: 25 PPMV NATURAL GAS (8) [**40CFR 60 Subpart KKKK, 7-6-2006**]; **PM10**: 0.01 GRAINS/SCF NATURAL GAS (5A) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF NATURAL GAS (5) [**RULE 409, 8-7-1981**]; **PM10**: 1.67 LBS/HR NATURAL GAS (5C) [**RULE 1303(b)(2)-Offset, 5-10-1996;** *RULE 1303(b)(2) -Offset, 12-6-2002*]; **PM10**: 11 LBS/HR NATURAL GAS (5B) [**RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) [**40CFR 72 - Acid Rain Provisions, 11-24-1997**]; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [**40CFR 60 Subpart 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*]	A63.1, A99.1, A99.2, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I298.1, K40.1

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(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 1: POWER GENERATION					
CO OXIDATION CATALYST, NO. 1, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476654	C3	D1 C4			
SELECTIVE CATALYTIC REDUCTION, NO. 1, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476654 AMMONIA INJECTION	C4	C3 S6		**NH3**: 5 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	A195.4, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 1, HEIGHT: 86 FT ; DIAMETER: 11 FT 8 IN A/N:	S6	C4			

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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
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Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: POWER GENERATION					
GAS TURBINE, NO. 2, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: GENERATOR, 50.95 MW	D7	C9	NOX: MAJOR SOURCE**	**CO**: 4 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]; **CO**: 2000 PPMV NATURAL GAS (5) **[RULE 407, 4-2-1982]**; **NOX**: 2.5 PPMV NATURAL GAS (4) [**RULE 2005, 6-3-2011**]; **NOX**: 25 PPMV NATURAL GAS (8) **[40CFR 60 Subpart KKKK, 7-6-2006]**; **PM10**: 0.01 GRAINS/SCF NATURAL GAS (5A) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF NATURAL GAS (5) **[RULE 409, 8-7-1981]**; **PM10**: 1.67 LBS/HR NATURAL GAS (5C) **[RULE 1303(b)(2)-Offset, 5-10-1996;** *RULE 1303(b)(2) -Offset, 12-6-2002*]; **PM10**: 11 LBS/HR NATURAL GAS (5B) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) **[40CFR 72 - Acid Rain Provisions, 11-24-1997]**; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) **[40CFR 60 Subpart 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*]	A63.1, A99.1, A99.2, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I298.2, K40.1

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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
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CANYON POWER PLANT

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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 1: POWER GENERATION					
CO OXIDATION CATALYST, NO. 2, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476657	C9	D7 C10			
SELECTIVE CATALYTIC REDUCTION, NO. 2, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476657 AMMONIA INJECTION	C10	C9 S12		NH3: 5 PPMV NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	A195.5, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 2, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N:	S12	C10			

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Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
Process 1: POWER GENERATION					
CO OXIDATION CATALYST, NO. 3, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476660	C15	D13 C16			
SELECTIVE CATALYTIC REDUCTION, NO. 3, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476660 AMMONIA INJECTION	C16	C15 S18		NH_3: 5 PPMV NATURAL GAS (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	A195.6, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 3, HEIGHT: 86 FT ; DIAMETER: 11 FT 8 IN A/N:	S18	C16			

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Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions* And Requirements	Conditions
Process 1: POWER GENERATION					
GAS TURBINE, NO. 4, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: GENERATOR, 50.95 MW	D19	C21	NOX: MAJOR SOURCE**	**CO**: 4 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]; **CO**: 2000 PPMV NATURAL GAS (5) **[RULE 407, 4-2-1982]**; **NOX**: 2.5 PPMV NATURAL GAS (4) **[RULE 2005, 6-3-2011]**; **NOX**: 25 PPMV NATURAL GAS (8) **[40CFR 60 Subpart KKKK, 7-6-2006]**; **PM10**: 0.01 GRAINS/SCF NATURAL GAS (5A) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **PM10**: 0.1 GRAINS/SCF NATURAL GAS (5) **[RULE 409, 8-7-1981]**; **PM10**: 1.67 LBS/HR NATURAL GAS (5C) **[RULE 1303(b)(2)-Offset, 5-10-1996;** *RULE 1303(b)(2) -Offset, 12-6-2002*]; **PM10**: 11 LBS/HR NATURAL GAS (5B) **[RULE 475, 10-8-1976;** *RULE 475, 8-7-1978*]; **SO2**: (9) **[40CFR 72 - Acid Rain Provisions, 11-24-1997]**; **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) **[40CFR 60 Subpart 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*]	A63.1, A99.1, A99.2, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I298.4, K40.1

* (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
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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 1: POWER GENERATION					
CO OXIDATION CATALYST, NO. 4, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476663	C21	D19 C22			
SELECTIVE CATALYTIC REDUCTION, NO. 4, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476663 AMMONIA INJECTION	C22	C21 S24		NH3: 5 PPMV NATURAL GAS (4) **[RULE 1303(a)(1)-BACT, 5-10-1996;** *RULE 1303(a)(1) -BACT, 12-6-2002*]	A195.7, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 4, HEIGHT: 86 FT ; DIAMETER: 11 FT 8 IN A/N:	S24	C22			
System 2: INTERNAL COMBUSTION ENGINE					

* (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
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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 1: POWER GENERATION					
INTERNAL COMBUSTION ENGINE, EMERGENCY POWER, DIESEL FUEL, CATERPILLAR, MODEL C-27, WITH AFTERCOOLER, TURBOCHARGER, 1141 BHP WITH A/N:	D25		NOX: PROCESS UNIT**	**CO**: 2.6 GRAM/BHP-HR DIESEL (8) **[40CFR 60 Subpart IIII, 1-30-2013]**; **CO**: 2.6 GRAM/BHP-HR DIESEL (4) **[RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1) -BACT, 12-6-2002*]; **NOX**: 225.48 LBS/1000 GAL DIESEL (1) **[RULE 2012, 5-6-2005]**; **NOX + ROG**: 4.8 GRAM/BHP-HR DIESEL (4) **[RULE 1303(a)(1) -BACT, 5-10-1996**; *RULE 1303(a)(1)-BACT, 12-6-2002*; **RULE 2005, 6-3-2011]**; **NOX + ROG**: 4.8 GRAM/BHP-HR DIESEL (8) **[40CFR 60 Subpart IIII, 1-30-2013]**; **PM**: 0.01 GRAM/BHP-HR DIESEL (4) **[RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1) -BACT, 12-6-2002*]; **PM**: 0.15 GRAM/BHP-HR DIESEL (8) **[40CFR 60 Subpart IIII, 1-30-2013]**; **PM**: 0.15 GRAM/BHP-HR DIESEL (5) [RULE 1470, 5-4-2012]; **SOX**: 0.005 GRAM/BHP-HR DIESEL (4) **[RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1) -BACT, 12-6-2002*]	B61.3, C1.1, D12.5, E193.1, E193.2, E193.3, E193.4, E193.5, I298.5, K67.2, K67.3

* (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
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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 1: POWER GENERATION					
FILTER, DIESEL PARTICULATES, CLEANAIR SYSTEMS PERMIT, MODEL FDA225, WITH HIBACK DATA LOGGING AND ALARM SYSTEM GENERATOR, 750 KW					
System 3: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, PRESSURE VESSEL, 19 PERCENT AQUEOUS AMMONIA, 10000 GALS; DIAMETER: 7 FT ; LENGTH: 42 FT A/N: 476665	D28				C157.1, E144.1, E193.1, K67.4
Process 2: OIL WATER SEPARATION					
OIL WATER SEPARATOR, UNDERGROUND, EMULSIFIED OIL AND WATER, 550 GALS; DIAMETER: 3 FT 6 IN; LENGTH: 7 FT 9 IN A/N: 481185	D29				E193.1
Process 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE SPECIFIC RULES					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, PORTABLE, ARCHITECTURAL COATINGS	E30			**VOC: (9) [RULE 1113, 11-8-1996;** *RULE 1113, 6-3-2011;* **RULE 1171, 11-7-2003;** *RULE 1171, 5-1-2009*]	K67.5
RULE 219 EXEMPT EQUIPMENT, EXEMPT HAND WIPING OPERATIONS	E32			**VOC: (9) [RULE 1171, 11-7-2003;** *RULE 1171, 5-1-2009*]	

* (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
CANYON POWER PLANT

SECTION D: 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
CANYON POWER PLANT

SECTION D: DEVICE ID INDEX

Device Index For Section D			
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C10	5	1	1
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C15	7	1	1
C16	7	1	1
S18	7	1	1
D19	8	1	1
C21	9	1	1
C22	9	1	1
S24	9	1	1
D25	11	1	2
D28	11	1	3
D29	11	2	0
E30	11	3	0
E32	11	3	0

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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]

DEVICE CONDITIONS

A. Emission Limits

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

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

CONTAMINANT	EMISSIONS LIMIT
VOC	Less than or equal to 412 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 540 LBS IN ANY CALENDAR MONTH
SOX	Less than or equal to 108 LBS IN ANY CALENDAR MONTH
VOC	Less than or equal to 3608 LBS IN ANY ONE YEAR
PM10	Less than or equal to 4822 LBS IN ANY ONE YEAR
SOX	Less than or equal to 971 LBS IN ANY ONE YEAR

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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 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 listed below)

For normal operation, including startups and shutdowns, the emission factors shall be as follows: VOC, 2.59 lb/mmcf; PM10, 3.40 lb/mmcf; and SOx, 0.68 lb/mmcf.

For maintenance operations, the emission factors shall be as follows: VOC, 2.64 lb/mmcf; PM10, 3.52 lb/mmcf; and SOx, 0.72 lb/mmcf.

For the purposes of this condition, the annual emission limit shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12-month period beginning on the first day of each calendar month.

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. The records shall include, but not be limited to, natural gas usage in a calendar month.

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D1, D7, D13, D19]

A99.1 The 2.5 PPM NOX emission limit(s) shall not apply during turbine start-up, shutdown, and maintenance periods. Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. Each turbine shall be limited to a maximum of 540 start-ups per year and a maximum of 10 hours of maintenance operations per year.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

For the purposes of this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

For the purposes of this condition, shutdown shall be defined as a reduction in turbine load ending in a period of zero fuel flow.

For the purposes of this condition, maintenance shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning and testing of the turbine control systems.

NOx emissions for an hour that includes a start-up shall not exceed 14.27 lbs, and for an hour that includes a shutdown 4.07 lbs. For the purpose of defining an hour that includes a start-up, the period begins when natural gas is first introduced into the turbine and ends after 60 minutes. The worst case includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence.

NOx emissions for maintenance operations shall not exceed 44.0 lbs in any hour.

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 2005, 6-3-2011]

[Devices subject to this condition : D1, D7, D13, D19]

A99.2 The 4.0 PPM CO emission limit(s) shall not apply during turbine start-up, shutdown, and maintenance periods. Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. Each turbine shall be limited to a maximum of 540 start-ups per year and a maximum of 10 hours of maintenance operations per year.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

For the purposes of this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

For the purposes of this condition, shutdown shall be defined as a reduction in turbine load ending in a period of zero fuel flow.

For the purposes of this condition, maintenance shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning and testing of the turbine control systems.

CO emissions for an hour that includes a start-up shall not exceed 11.6 lbs, and for an hour that includes a shutdown 4.15 lbs. For the purpose of defining an hour that includes a start-up, the period begins when natural gas is first introduced into the turbine and ends after 60 minutes. The worst case includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence.

CO emissions for maintenance operations shall not exceed 19.4 lbs in any hour.

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]

[Devices subject to this condition : D1, D7, D13, D19]

A99.3 The 2.0 PPM ROG emission limit(s) shall not apply during turbine start-up, shutdown, and maintenance periods. Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. Each turbine shall be limited to a maximum of 540 start-ups per year and a maximum of 10 hours of maintenance operations per year.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

For the purposes of this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

For the purposes of this condition, shutdown shall be defined as a reduction in turbine load ending in a period of zero fuel flow.

For the purposes of this condition, maintenance shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning and testing of the turbine control systems.

ROG emissions for an hour that includes a start-up shall not exceed 1.29 lbs, and for an hour that includes a shutdown 1.27 lbs. For the purpose of defining an hour that includes a start-up, the period begins when natural gas is first introduced into the turbine and ends after 60 minutes. The worst case includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence.

ROG emissions for maintenance operations shall not exceed 1.25 lbs in any hour.

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]

[Devices subject to this condition : D1, D7, D13, D19]

A195.1 The 2.5 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

[RULE 2005, 6-3-2011]

[Devices subject to this condition : D1, D7, D13, D19]

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

A195.2 The 4.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

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

[Devices subject to this condition : D1, D7, D13, D19]

A195.3 The 2.0 PPMV ROG emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

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

[Devices subject to this condition : D1, D7, D13, D19]

A195.4 The 5 PPMV NH3 emission limit(s) is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following equation.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

NH3 (ppmv) = 0.348 * [a-b*c/1E+06]*1E+06/b; where

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

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

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

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

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

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

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

[Devices subject to this condition : C4]

A195.5 The 5 PPMV NH3 emission limit(s) is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following equation.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

NH3 (ppmv) = 0.432 * [a-b*c/1E+06]*1E+06/b; where

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

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

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

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

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

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

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

[Devices subject to this condition : C10]

A195.6 The 5 PPMV NH3 emission limit(s) is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following equation.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

NH_3 (ppmv) = 0.368 * [a-b*c/1E+06]*1E+06/b; where

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

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

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

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

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

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

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

[Devices subject to this condition : C16]

A195.7 The 5 PPMV NH_3 emission limit(s) is averaged over 60 minutes at 15% O_2, dry basis. The operator shall calculate and continuously record the NH_3 slip concentration using the following equation.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

NH3 (ppmv) = 0.296 * [a-b*c/1E+06]*1E+06/b; where

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

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

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

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

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

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

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

[Devices subject to this condition : C22]

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 : D1, D7, D13, D19]

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

B. Material/Fuel Type Limits

B61.1 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 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D1, D7, D13, D19]

B61.3 The operator shall not use diesel fuel containing the following specified compounds:

Compound	Range	ppm by weight
Sulfur	greater than	15

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **40CFR 60 Subpart IIII, 1-30-2013]**

[Devices subject to this condition : D25]

C. Throughput or Operating Parameter Limits

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

C1.1 The operator shall limit the operating time to no more than 50 hour(s) in any one year.

The 50 hours in any one year shall include no more than 50 hours in any one year for maintenance and performance testing and no more than 4.2 hours in any one month for maintenance and performance testing..

The duration of each test shall not exceed 38 minutes in any one hour.

[RULE 1110.2, 2-1-2008; RULE 1110.2, 9-7-2012; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 9-10-2010; RULE 1470, 5-4-2012; **RULE 2012, 5-6-2005; 40CFR 60 Subpart IIII, 1-30-2013;** CA PRC CEQA, 11-23-1970]

[Devices subject to this condition : D25]

C157.1 The operator shall install and maintain a pressure relief valve set at 25 psig.

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

[Devices subject to this condition : D28]

D. Monitoring/Testing Requirements

D12.1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the turbine.

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

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 2012, 5-6-2005]**

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

[Devices subject to this condition : D1, D7, D13, D19]

D12.2 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the 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 calibration records shall be kept on site and made available to District personnel upon request.

The ammonia injection system shall be placed in full operation as soon as the minimum temperature at the outlet to the SCR reactor is reached. The minimum temperature is 540 deg F.

The ammonia injection rate shall remain between 52.32 lb/hr and 122.57 lb/hr.

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

[Devices subject to this condition : C4, C10, C16, C22]

D12.3 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature of the exhaust at the inlet to the SCR reactor.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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 catalyst temperature range shall remain between 665 deg F and 870 deg F.

The catalyst inlet temperature shall not exceed 870 deg F.

The temperature range requirement of this condition shall not apply during start-up conditions of the turbine not to exceed 35 minutes per start-up. For this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

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

[Devices subject to this condition : C4, C10, C16, C22]

D12.4 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the 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 drop across the catalyst shall not exceed 8 inches water column.

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

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

[Devices subject to this condition : C4, C10, C16, C22]

D12.5 The operator shall install and maintain a(n) non-resettable elapsed time meter to accurately indicate the elapsed operating time of the engine.

[RULE 1110.2, 2-1-2008; RULE 1110.2, 9-7-2012; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 9-10-2010; RULE 1470, 5-4-2012; **RULE 2012, 5-6-2005; 40CFR 60 Subpart IIII, 1-30-2013]**

[Devices subject to this condition : D25]

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

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

The test(s) shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

If the turbine is not in operation during one quarter, then no testing is required during that quarter.

The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted and the results submitted to the District within 60 days after the test date.

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 : D1, D7, D13, D19]

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

Pollutant(s) to be tested	Required Test Method(s)	Sampling Time	Test Location
SOX emissions	AQMD Laboratory Method 307-91	Not Applicable	Fuel sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM emissions	District method 5.1	4 hours	Outlet of the SCR serving this equipment

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

PM10 emissions	EPA Method 201A	4 hours	Outlet of the SCR serving this equipment

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

In the above table, PM emissions mean total PM emissions. The PM10 test method is EPA Method 201A/District Method 5.1. For PM and PM10 emissions, the sampling time is a minimum of four hours.

For SOx and VOC, the test shall be conducted at least once every three years. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

For PM and PM10, the tests shall be conducted at least once every 18 months in order to verify compliance with the emission rate of 1.67 lb/hr at maximum load during normal operations. These source tests shall be conducted using the protocol dated September 27, 2013 and approved by the SCAQMD on October 10, 2013. Protocol approval indicated three Method 201A/5.1 runs per unit will be required for future compliance tests.

If all tests conducted over a three-year period comply with the 1.67 lb/hr limit for PM10, the facility shall have the option of reducing the source test frequency to once every three years.

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

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

The test shall be conducted when this equipment is operating at loads of 100, 75, and 50 percent, with the exception of PM and PM10 testing. For PM and PM10, the test shall be conducted when this equipment is operating at a load of 100 percent.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and AQMD, may be the following: a) Triplicate stack gas samples are extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of the Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is

per unmodified EPA Method TO-12 (with preconcentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmvC or less and reported to two significant figures, and (d) The temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees Fahrenheit. The test results shall be reported to two significant digits.

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

For the purposes of this condition, an alternative test method may be allowed for VOC emissions upon concurrence of AQMD, EPA, and CARB.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D1, D7, D13, D19]

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

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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 operating no later than 90 days after initial startup of the turbine, in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. Witnin two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

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

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 218, 8-7-1981; RULE 218, 5-14-1999**]

[Devices subject to this condition : D1, D7, D13, D19]

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 shall comply with the requirements of Rule 2012. 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). Within two weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start-up of the turbine.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

[RULE 2005, 6-3-2011; RULE 2012, 5-6-2005]

[Devices subject to this condition : D1, D7, D13, D19]

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 : D28]

E179.1 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 upon the average of the continuous monitoring for that hour.

Condition Number D 12- 2

Condition Number D 12- 3

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

[Devices subject to this condition : C4, C10, C16, C22]

E179.2 For the purpose of the following condition number(s), continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continous monitoring for that month.

Condition Number D 12- 4

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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 2005, 6-3-2011**]

[Devices subject to this condition : C4, C10, C16, C22]

E193.1 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 07-AFC-9 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition : D1, C4, D7, C10, D13, C16, D19, C22, D25, D28, D29]

E193.2 The operator shall operate and maintain this equipment according to the following requirements:

The operation of this engine for emergency use shall be allowed only in the event of a loss of grid power or up to 30 minutes prior to a rotating outage, provided that the utility distribution company has ordered rotating outages in the control area where the engine is located or has indicated that it expects to issue such an order at a certain time, and the engine is located in a utility service block that is subject to the rotating outage.

Engine operation shall be terminated immediately after the utility distribution company advises that a rotating outage is no longer imminent or in effect.

The engine shall be operated for the primary purpose of providing a back up source of power to start a turbine.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

[**RULE 1110.2, 2-1-2008;** RULE 1110.2, 9-7-2012; **RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 9-10-2010; RULE 1470, 5-4-2012; **RULE 2012, 5-6-2005]**

[Devices subject to this condition : D25]

E193.3 The operator shall operate and maintain this equipment according to the following specifications:

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

The operator shall operate the diesel particulate filter system only with an operational HiBACK data logging and alarm system with backpressure and temperature monitors.

The HiBACK data logging and alarm system shall be programmed to provide a red warning signal and an audible alarm, whenever the engine backpressure reaches the maximum allowable backpressure of 40 inches of water. The engine backpressure shall not exceed 40 inches of water in operation.

The engine shall be operated at the load level required to achieve an engine exhaust gas temperature of 572 deg F (300 deg C) for passive regeneration of the diesel particulate filter for at least 30% of the operating time.

The engine shall not be operated below the passive regeneration temperature of 572 deg F for more than 240 consecutive minutes.

The operator shall regenerate the diesel particulate filter (i) after every 24 cold starts since the last regeneration, or (ii) whenever a yellow warning signal indicating the backpressure is 10% below the allowable backpressure of 40 inches of water is received from the HiBACK alarm system, whichever occurs first. Filter regeneration is complete when the backpressure monitoring system indicates a normal backpressure reading.

The engine shall be shut down and the diesel particulate filter shall be cleaned whenever the backpressure reaches the maximum backpressure limit of 40 inches water. Cleaning shall be performed according to the manufacturer's recommendations in the installation and maintenance manual.

After every 200 hours of normal engine operation, the operator shall inspect the integrity of the diesel particulate filter and, if necessary, replace it.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **40CFR 60 Subpart IIII, 1-30-2013]**

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

[Devices subject to this condition : D25]

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

Removal of the diesel particulate filter media for cleaning may only occur under the following conditions:

A. The internal combustion engine shall not be operated for maintenance and testing or any other non-emergency use while the diesel particulate filter media is removed; and

B. The diesel particulate filter media shall be returned and re-installed within 10 working days from the date of removal; and

C. The owner or operator shall maintain records indicating the date(s) the diesel particulate filter media was removed for cleaning and the date(s) the filter media was re-installed. Records shall be retained for a minimum of five years.

[RULE 1470, 5-4-2012]

[Devices subject to this condition : D25]

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

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

The operator shall operate and maintain the stationary engine and diesel particulate filter according to the manufacturer's written emission-related instructions (or procedures developed by the operator that are approved by the engine manufacturer), change only those emission-related settings that are permitted by the manufacturer, and meet the requirements of 40 CFR 89, 94 and/or 1068, as they apply.

The operator shall comply with the emission standards specified in 40 CFR 60.4205(b) by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications.

[40CFR 60 Subpart IIII, 1-30-2013]

[Devices subject to this condition : D25]

H. Applicable Rules

H23.1 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
NOX	40CFR60, SUBPART	KKKK
SOX	40CFR60, SUBPART	KKKK

[40CFR 60 Subpart KKKK, 7-6-2006]

[Devices subject to this condition : D1, D7, D13, D19]

I. Administrative

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

I298.1 This equipment shall not be operated unless the facility holds 15017 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 15017 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition : D1]

I298.2 This equipment shall not be operated unless the facility holds 15017 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 15017 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

[RULE 2005, 6-3-2011]

[Devices subject to this condition : D7]

I298.3 This equipment shall not be operated unless the facility holds 15017 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 15017 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition : D13]

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

I298.4 This equipment shall not be operated unless the facility holds 15017 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 15017 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition : D19]

I298.5 This equipment shall not be operated unless the facility holds 603 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 603 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

[**RULE 2005, 6-3-2011**]

[Devices subject to this condition : D25]

K. Record Keeping/Reporting

K40.1 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.

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

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (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, fuel flow rate (CFH), the heating content of the fuel, the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 2005, 6-3-2011**]

[Devices subject to this condition : D1, D7, D13, D19]

K67.2 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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

An engine operating log shall be maintained which on a monthly basis shall list all engine operations in each of the following areas:

A. Emergency use hours of operation,

B. Maintenance and testing hours, and

C. Other operating hours, with a description of the reason for operation.

In addition, each time the engine is started manually, the log shall include the date of operation and the timer readings in hours at the beginning and end of operation. The log shall be kept for a minimum of five calendar years prior to the current year and made available to District personnel upon request. The total hours of operation for the previous calendar year shall be recorded some time during the first 15 days of January each year.

[**RULE 1110.2, 2-1-2008**; RULE 1110.2, 9-7-2012; **40CFR 60 Subpart IIII, 1-30-2013**]

[Devices subject to this condition : D25]

K67.3 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

The operator shall maintain records of diesel particulate filter inspections, replacements, and cleaning.

The operator shall maintain monthly records of the exhaust temperature, engine backpressure, and date and time for the duty cycle as downloaded from the HiBACK data logging and alarm system.

All records shall be maintained on file for a minimum of five years and made available to District personnel upon request.

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

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; **40CFR 60 Subpart IIII, 1-30-2013]**

[Devices subject to this condition : D25]

K67.4 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

The operator shalll document an inspection each time the tank is filled to ensure the vapor recovery equipment is consistently and properly used.

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

[Devices subject to this condition : D28]

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

For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records for all coating consisting of (a) coating type, (b) VOC content as supplied in grams per liter (g/l) of materials for low-solids coatings, (c) VOC content as supplied in g/l of coating, less water and exempt solvent, for other coatings.

For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

[RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997]

[Devices subject to this condition : E30]

FACILITY PERMIT TO OPERATE
CANYON POWER PLANT

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

NONE

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 110	PAGE 1
ENGINEERING AND COMPLIANCE DIVISION	APPL. NO. 555827, -828, -829, -830, -831, -832	DATE 12/9/14
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY

CANYON POWER PLANT
201 S. ANAHEIM BLVD.
ANAHEIM, CA 92805-3821

FACILITY ID: 153992

EQUIPMENT LOCATION:3071 E. Miraloma Ave.
Anaheim, CA 92806-1809

Responsible Official: Manny Robledo, Electric Operations Manager (714) 765-5107

PERMITS TO OPERATE
(Modification to Increase Turbines Operating Schedule)

EQUIPMENT DESCRIPTION

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 1: POWER GENERATION					
SYSTEM 1: GAS TURBINES					
GAS TURBINE, NO. 1, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: ~~531829~~ **555828**	D1	C3	NOX: MAJOR SOURCE	**CO**: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **CO**: 4 PPMV NATURAL GAS (4) ~~[RULE 1703(a)(2)-PSD-BACT, 10-7-1988~~ **RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]** **NOX**: 2.5 PPMV NATURAL GAS (4) ~~[RULE 1703(a)(2)-PSD-BACT, 10-7-1988;~~ RULE 2005, 6-3-2011]; **NOX**: 25 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006] **PM10**: 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; **PM10**: 0.01 GRAINS/SCF NATURAL GAS (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10**: 11 LBS/HR NATURAL GAS (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10: 1.67 LBS/HR NATURAL GAS (5C) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]** **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997]	A63.1, A99.1, A99.2, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I298.1, K40.1, ~~K67.1~~
GENERATOR, 50.95 MW	[B2]				

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				SOX: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart 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. 1, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476654	C3	D1 C4			
SELECTIVE CATALYTIC REDUCTION, NO. 1, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476654 AMMONIA INJECTION	C4 [B5]	C3 S6		**NH3**: 5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.4, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 1, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N: ~~531829~~ 555828	S6	C4			
GAS TURBINE, NO. 2, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: ~~531831~~ 555829 GENERATOR, 50.95 MW	D7 [B8]	C9	NOX: MAJOR SOURCE	**CO**: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **CO**: 4 PPMV NATURAL GAS (4) [~~RULE 1703(a)(2) PSD-BACT, 10-7-1988~~ **RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**] **NOX**: 2.5 PPMV NATURAL GAS (4) [~~RULE 1703(a)(2) PSD-BACT, 10-7-1988;~~ RULE 2005, 6-3-2011]; **NOX**: 25 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006] **PM10**: 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; **PM10**: 0.01 GRAINS/SCF NATURAL GAS (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10**: 11 LBS/HR NATURAL GAS (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10: 1.67 LBS/HR NATURAL GAS (5C) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]** **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997] **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-	A63.1, A99.1, A99.2, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I298.2, K40.1, ~~K67.1~~

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 110	PAGE 3
ENGINEERING AND COMPLIANCE DIVISION	APPL. NO. 555827, -828, -829, -830, -831, -832	DATE 12/9/14
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				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. 2, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476657	C9	D7 C10			
SELECTIVE CATALYTIC REDUCTION, NO. 2, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476657 AMMONIA INJECTION	C10 [B11]	C9 S12		**NH3**: 5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.5, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 2, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N: ~~531831~~ **555829**	S12	C10			
GAS TURBINE, NO. 3, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: ~~531832~~ **555830** GENERATOR, 50.95 MW	D13 [B14]	C15	NOX: MAJOR SOURCE	**CO**: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **CO**: 4 PPMV NATURAL GAS (4) [~~RULE 1703(a)(2)-PSD-BACT, 10-7-1988~~ **RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**] **NOX**: 2.5 PPMV NATURAL GAS (4) [~~RULE 1703(a)(2)-PSD-BACT, 10-7-1988;~~ RULE 2005, 6-3-2011]; **NOX**: 25 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006] **PM10**: 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; **PM10**: 0.01 GRAINS/SCF NATURAL GAS (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10**: 11 LBS/HR NATURAL GAS (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10: 1.67 LBS/HR NATURAL GAS (5C) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]** **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997] **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]	A63.1, A99.1, A99.2, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I298.3, K40.1, ~~K67.1~~

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				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. 3, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476660	C15	D13 C16			
SELECTIVE CATALYTIC REDUCTION, NO. 3, CORMETECH CMHT-21, 1012 CU. FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476660 AMMONIA INJECTION	C16 [B17]	C15 S18		**NH3**: 5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.6, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 3, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N: ~~531832~~ <u>555830</u>	S18	C16			
GAS TURBINE, NO. 4, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: ~~531833~~ <u>555831</u> GENERATOR, 50.95 MW	D19 [B20]	C21	NOX: MAJOR SOURCE	**CO**: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **CO**: 4 PPMV NATURAL GAS (4) [~~RULE 1703(a)(2)-PSD-BACT, 10-7-1988~~ <u>**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**</u>] **NOX**: 2.5 PPMV NATURAL GAS (4) [~~RULE 1703(a)(2)-PSD-BACT, 10-7-1988;~~ RULE 2005, 6-3-2011]; **NOX**: 25 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006] **PM10**: 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; **PM10**: 0.01 GRAINS/SCF NATURAL GAS (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10**: 11 LBS/HR NATURAL GAS (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; <u>**PM10: 1.67 LBS/HR NATURAL GAS (5C) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]**</u> **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997] **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006] **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996;	A63.1, A99.1, A99.2, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1, D29.2, D29.3, D82.1, D82.2, E193.1, H23.1, I298.4, K40.1, ~~K67.1~~

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. 4, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476663	C21	D19 C22			
SELECTIVE CATALYTIC REDUCTION, NO. 4, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476663 AMMONIA INJECTION	C22 [B23]	C21 S24		**NH3**: 5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.7, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 4, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N: ~~531833~~ 555831	S24	C22			
SYSTEM 2: INTERNAL COMBUSTION ENGINE					
INTERNAL COMBUSTION ENGINE, EMERGENCY POWER, DIESEL FUEL, CATERPILLAR, MODEL C-27, WITH AFTERCOOLER, TURBOCHARGER, 1141 BHP WITH A/N: ~~476666~~ 555832 FILTER, DIESEL PARTICULATES, CLEANAIR SYSTEMS PERMIT, MODEL FDA225, WITH HIBACK DATA LOGGING AND ALARM SYSTEM GENERATOR, 750 KW	D25 [B26] [B27]		NOX: PROCESS UNIT**	**CO**: 2.6 GRAM/BHP-HR DIESEL (4) [~~RULE 1703(a)(2)-PSD-BACT, 10-7-1988~~ **RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]** **CO: 2.6 GRAM/BHP-HR DIESEL (8) [40 CFR 60 SUBPART IIII, 1-30-2013]** **NOX**: 225.48 LBS/1000 GAL DIESEL (1) [RULE 2012, 5-6-2005] **NOX + ROG**: 4.8 GRAM/BHP-HR DIESEL (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~~; RULE 2005, 6-3-2011] **NOX + ROG: 4.8 GRAM/BHP-HR DIESEL (8) 40 CFR 60 SUBPART IIII, 1-30-2013]** **PM~~10~~**: ~~0.15~~ 0.01 GRAM/BHP-HR DIESEL (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002] **PM: 0.15 GRAM/BHP-HR DIESEL (5) [RULE 1470, 5-4-2012]** **PM: 0.15 GRAM/BHP-HR DIESEL (8) [40 CFR 60 SUBPART IIII, 1-30-2013]**	**B61.3**, C1.1, D12.5, E193.1, E193.2, E193.3, **E193.4, E193.5,** I298.5, K67.2, K67.3

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				SOX: 0.005 GRAM/BHP-HR DIESEL (4) [RULE 1303(a)(1)-BACT, 5-10-1996, RULE 1303(a)(1), 12-6-2002]	

* (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

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 diesel fuel containing sulfur compounds in excess of 15 ppm by weight as supplied by the supplier.~~

~~Material safety data sheets for the diesel fuel shall be kept current and made available to District personnel upon request.~~

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

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]

DEVICE CONDITIONS

GAS TURBINES

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

CONTAMINANT	EMISSION LIMIT
VOC	Less than or equal to ~~129~~ **412** LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to ~~299~~ **540** LBS IN ANY CALENDAR MONTH
SOx	Less than or equal to ~~34~~ **108** LBS IN ANY CALENDAR MONTH
VOC	**Less than or equal to 3608 LBS IN ANY YEAR**
PM10	**Less than or equal to 4822 LBS IN ANY YEAR**
SOx	**Less than or equal to 971 LBS IN ANY YEAR**

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 District 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, 3.76 lb/mmcf; PM10, 6.03 lb/mmcf; and SOx, 0.68 lb/mmcf.~~

For normal operation, **including startups and shutdowns**, the emission factors shall be as follows: VOC, 2.59 lb/mmcf; PM10, ~~6.03~~ **3.40** lb/mmcf; and SOx, 0.68 lb/mmcf.
[Note: See Table 17 for EF calculations.]

For maintenance operations, the emission factors shall be as follows: VOC, 2.64 lb/mmcf; PM10, 3.52 lb/mmcf; and SOx, 0.72 lb/mmcf.

[Note: See Table 16 for EF calculations.]

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

For the purposes of this condition, the annual emission limit shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12-month period beginning on the first day of each calendar month.

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. **The records shall include, but not be limited to, natural gas usage in a calendar month.**

[RULE 1303(b)(2)–Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition: D1, D7, D13, D19]

A99.1 The 2.5 PPM NOx emission limit(s) shall not apply during turbine ~~commissioning~~, start-up, ~~and~~ shutdown**, and maintenance** periods. ~~Commissioning shall not exceed 156 hours total.~~ Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. ~~The~~ **Each** turbines shall be limited to a maximum of ~~240~~ **540** start-ups per year **and a maximum of 10 hours of maintenance operations per year**.

For the purposes of this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

For the purposes of this condition, shutdown shall be defined as a reduction in turbine load ending in a period of zero fuel flow.

For the purposes of this condition, maintenance shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning and testing of the turbine control systems.

NOx emissions for an hour that includes a start-up shall not exceed 14.27 lbs, and for an hour that includes a shutdown 4.07 lbs. For the purpose of defining an hour that includes a start-up, the period begins when natural gas is first introduced into the turbine and ends after 60 minutes. The worst case includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence.

NOx emissions for maintenance operations shall not exceed 44.0 lbs in any hour.

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 1703(a)(2) - PSD-BACT, 10-7-1988;~~ RULE 2005, 6-3-2011]

[Devices subject to this condition: D1, D7, D13, D19]

A99.2 The 4.0 PPM CO emission limit(s) shall not apply during turbine ~~commissioning~~, start-up, ~~and~~ shutdown**, and maintenance** periods. ~~Commissioning shall not exceed 156 hours total.~~ Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. ~~The~~ **Each** turbine shall be limited to a maximum of ~~240~~ **540** start-ups per year **and a maximum of 10 hours of maintenance operations per year**.

For the purposes of this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

For the purposes of this condition, shutdown shall be defined as a reduction in turbine load ending in a period of zero fuel flow.

For the purposes of this condition, maintenance shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning and testing of the turbine control systems.

CO emissions for an hour that includes a start-up shall not exceed 11.6 lbs, and for an hour that includes a shutdown 4.15 lbs. For the purpose of defining an hour that includes a start-up, the period begins when natural gas is first introduced into the turbine and ends after 60 minutes. The worst case includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence.

CO emissions for maintenance operations shall not exceed 19.4 lbs in any hour.

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

[Devices subject to this condition: D1, D7, D13, D19]

A99.3 The 2.0 PPM ROG emission limit(s) shall not apply during turbine ~~commissioning~~, start-up, ~~and~~ shutdown**, and maintenance** periods. ~~Commissioning shall not exceed 156 hours total.~~ Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. ~~The~~ **Each** turbine shall be limited to a maximum of ~~240~~ **540** start-ups per year **and a maximum of 10 hours of maintenance operations per year**.

For the purposes of this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

<u>**For the purposes of this condition, shutdown shall be defined as a reduction in turbine load ending in a period of zero fuel flow.**</u>

<u>**For the purposes of this condition, maintenance shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning and testing of the turbine control systems.**</u>

ROG emissions for an hour that includes a start-up shall not exceed 1.29 lbs, and for an hour that includes a shutdown 1.27 lbs. For the purpose of defining an hour that includes a start-up, the period begins when natural gas is first introduced into the turbine and ends after 60 minutes. The worst case includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence.

<u>**ROG emissions for maintenance operations shall not exceed 1.25 lbs in any hour.**</u>

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]

[Devices subject to this condition: D1, D7, D13, D19]

A195.1 The 2.5 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

[~~RULE 1703(a)(2) - PSD-BACT, 10-7-1988~~; RULE 2005, 6-3-2011]

[Devices subject to this condition: D1, D7, D13, D19]

A195.2 The 4.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

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

[Devices subject to this condition: D1, D7, D13, D19]

A195.3 The 2.0 PPMV ROG emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

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

[Devices subject to this condition: D1, D7, D13, D19]

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: D1, D7, D13, D19]

B61.1 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 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition: D1, D7, D13, D19]

D12.1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the turbine.

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

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 2012, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

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

The test(s) shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

If the turbine is not in operation during one quarter, then no testing is required during that quarter.

The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted and the results submitted to the District within 60 days after the test date.

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: D1, D7, D13, D19]

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

Pollutant(s) to be tested	Required Test Method(s)	Sampling Time	Test Location
SOX emissions	AQMD Laboratory Method 307-91	Not Applicable	Fuel sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM emissions	**District Method 5.1**	**4 hours**	**Outlet of the SCR serving this equipment**
PM10 emissions	~~District Method 5~~ **EPA Method 201A**	4 hours	Outlet of the SCR serving this equipment

In the above table, PM emissions mean total PM emissions. The PM10 test method is EPA Method 201A/District Method 5.1. For PM and PM10 emissions, the sampling time is a minimum of four hours.

For SOx and VOC, ~~T~~ the test shall be conducted at least once every three years. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

For PM and PM_{10}, the tests shall be conducted at least once every 18 months in order to verify compliance with the emission rate of 1.67 lb/hr at maximum load during normal operations. These source tests shall be conducted using the protocol dated September 27, 2013 and approved by the SCAQMD on October 10, 2013. Protocol approval indicated three Method 201A/5.1 runs per unit will be required for future compliance tests.

If all tests conducted over a three-year period comply with the 1.67 lb/hr limit for PM10, the facility shall have the option of reducing the source test frequency to once every three years.

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

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

The test shall be conducted when this equipment is operating at loads of 100, 75, and 50 percent, with the exception of **PM and** PM10 testing. For **PM and** PM10, the test shall be conducted when this equipment is operating at a load of 100 percent.

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and AQMD, may be the following: a) Triplicate stack gas samples are extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of the Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per unmodified EPA Method TO-12 (with preconcentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmvC or less and reported to two significant figures, and (d) The temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees Fahrenheit. The test results shall be reported to two significant digits.

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

For the purposes of this condition, an alternative test method may be allowed for VOC emissions upon concurrence of AQMD, EPA, and CARB.

~~For the purposes of this condition, an alternative District approved test method for measuring PM10 emissions may be allowed for PM10 emissions.~~

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

[Devices subject to this condition: D1, D7, D13, D19]

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 operating no later than 90 days after initial startup of the turbine, in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. Within two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

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

[~~RULE 1703(a)(2)-PSD-BACT, 10-7-1988~~ **RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; RULE 218, 8-7-1981; RULE 218, 5-14-1999]

[Devices subject to this condition: D1, D7, D13, D19]

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 shall comply with the requirements of Rule 2012. 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). Within two weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start-up of the turbine.

[~~RULE 1703(a)(2)-PSD-BACT, 10-7-1988~~; RULE 2005, 6-3-2011; RULE 2012, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

E193.1 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 07-AFC-9 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C4, D7, C10, D13, C16, D19, C22, D25, D28, D29]

H23.1 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
NOx	40CFR60, SUBPART	KKKK
SOX	40CFR60, SUBPART	KKKK

[40 CFR 60 Subpart KKKK, 7-6-2006]

[Devices subject to this condition: D1, D7, D13, D19]

I298.1 This equipment shall not be operated unless the facility holds ~~9677~~ <u>15017</u> pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds ~~6886~~ <u>15017</u> pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: D1]

I298.2 This equipment shall not be operated unless the facility holds ~~9677~~ <u>15017</u> pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds ~~6886~~ <u>15017</u> pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: D7]

I298.3 This equipment shall not be operated unless the facility holds ~~9677~~ <u>15017</u> pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds ~~6886~~ <u>15017</u> pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: D13]

I298.4 This equipment shall not be operated unless the facility holds ~~9677~~ <u>15017</u> pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds ~~6886~~ <u>15017</u> pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: D19]

K40.1 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.

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

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (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, fuel flow rate (CFH), the heating content of the fuel, the flue gas temperature, and the generator power output (MW) under which the test was conducted.

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

[Devices subject to this condition: D1, D7, D13, D19]

~~K67.1 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.~~

~~Natural gas fuel use after the commissioning period and prior to CEMS certification.~~

~~Natural gas fuel use after CEMS certification.~~
Note: Added to recordkeeping requirements for condition A63.1.

~~[RULE 2005, 6-3-2011]~~

~~[Devices subject to this condition: D1, D7, D13, D19]~~

SCR/CO CATALYSTS

Note: *Applications were not required to be submitted for the SCR/CO catalysts. To assist the SCAQMD inspector, however, condition D12.2 will be revised to provide the injection rate in lb/hr to match the units of the meters.*

In addition, Rule 1703(a)(2)-PSD-BACT will be removed as a rule tag from conditions D12.3, D12.4, E179.1, and E179.2, because CPP is not PSD.

D12.2 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the 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 calibration records shall be kept on site and made available to District personnel upon request.

The ammonia injection system shall be placed in full operation as soon as the minimum temperature at the outlet to the SCR reactor is reached. The minimum temperature is 540 deg F.

The ammonia injection rate shall remain between ~~6.83 gal/hr and 16 gal/hr~~ **<u>52.32 lb/hr and 122.57 lb/hr</u>**.

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

[Devices subject to this condition: C4, C10, C16, C22]

BLACK START ENGINE

<u>B61.3 The operator shall not use diesel fuel containing the following specified compounds:</u>

Compound	**Range**	**ppm by weight**
Sulfur	**Greater than**	**15**

<u>[RULE 1303(a)(1) – BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; 40 CFR 60 Subpart IIII, 1-30-2013]</u>

<u>[Devices subject to this condition: D25]</u>

C1.1 The operator shall limit the operating time to no more than ~~200~~ **<u>50</u>** hour(s) in any one year.

The ~~200~~ **<u>50</u>** hours in any one year shall include no more than 50 hours **<u>in any one year</u>** for maintenance and performance testing **<u>and no more than 4.2 hours in any one month for maintenance and performance testing</u>**.

The duration of each test shall not exceed 38 minutes in any one hour.

[RULE 1110.2, ~~7-9-2010~~ **<u>2-1-2008; RULE 1110.2, 9-7-2012</u>**; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 9-10-2010; RULE 1470, 5-4-2012; RULE 2012, 5- 6-2005; **<u>40 CFR 60 Subpart IIII, 1-30-2013;</u>** CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D25]

D12.5 The operator shall install and maintain a(n) non-resettable elapsed time meter to accurately indicate the elapsed operating time of the engine.

[RULE 1110.2, ~~7-9-2010~~ **2-1-2008; RULE 1110.2, 9-7-2012**; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 9-10-2010; RULE 1470, 5-4-2012; RULE 2012, 5- 6-2005**; 40 CFR 60 Subpart IIII, 1-30-2013**]

[Devices subject to this condition: D25]

E193.1 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 07-AFC-9 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C4, D7, C10, D13, C16, D19, C22, D25, D28, D29]

E193.2 The operator shall operate and maintain this equipment according to the following requirements:

The operation of this engine ~~beyond the 50 hours per year allotted for maintenance and performance testing~~ **for emergency use** shall be allowed only in the event of a loss of grid power or up to 30 minutes prior to a rotating outage, provided that the utility distribution company has ordered rotating outages in the control area where the engine is located or has indicated that it expects to issue such an order at a certain time, and the engine is located in a utility service block that is subject to the rotating outage.

Engine operation shall be terminated immediately after the utility distribution company advises that a rotating outage is no longer imminent or in effect.

This engine shall be operated for the primary purpose of providing a back up source of power to start a turbine.

[RULE 1110.2, ~~7-9-2010~~ **2-1-2008; RULE 1110.2, 9-7-2012**; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 9-10-2010; RULE 1470, 5-4-2012; RULE 2012, 5- 6-2005]

[Devices subject to this condition: D25]

E193.3 The operator shall operate and maintain this equipment according to the following specifications:

The operator shall operate the diesel particulate filter system only with an operational HiBACK data logging and alarm system with backpressure and temperature monitors.

The HiBACK data logging and alarm system shall be programmed to provide a red warning signal and an audible alarm, whenever the engine backpressure reaches the maximum allowable backpressure of 40 inches of water. The engine backpressure shall not exceed 40 inches of water in operation.

The engine shall be operated at the load level required to achieve an engine exhaust gas temperature of 572 deg F (300 deg C) for passive regeneration of the diesel particulate filter for at least 30% of the operating time.

The engine shall not be operated below the passive regeneration temperature of 572 deg F for more than 240 consecutive minutes.

The operator shall regenerate the diesel particulate filter (i) after every 24 cold starts since the last regeneration, or (ii) whenever a yellow warning signal indicating the backpressure is 10% below the maximum allowable backpressure of 40 inches of water is received from the HiBACK alarm system, whichever occurs first. Filter regeneration is complete when the backpressure monitoring system indicates a normal backpressure reading.

The engine shall be shut down and the diesel particulate filter shall be cleaned whenever the backpressure reaches the maximum backpressure limit of 40 inches water. Cleaning shall be performed according to the manufacturer's recommendations in the installation and maintenance manual.

After every 200 hours of normal engine operation, the operator shall inspect the integrity of the diesel particulate filter and, if necessary, replace it.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **40 CFR 60 Subpart IIII, 1-30-2013]**

[Devices subject to this condition: D25]

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

Removal of the diesel particulate filter media for cleaning may only occur under the following conditions:

A. The internal combustion engine shall not be operated for maintenance and testing or any other non-emergency use while the diesel particulate filter media is removed; and

B. The diesel particulate filter media shall be returned and re-installed within 10 working days from the date of removal; and

C. The owner or operator shall maintain records indicating the date(s) the diesel particulate filter media was removed for cleaning and the date(s) the filter media was re-installed. Records shall be retained for a minimum of five years.

[RULE 1470, 5-4-2012]

[Devices subject to this condition: D25]

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

<u>The operator shall operate and maintain the stationary engine and diesel particulate filter according to the manufacturer's written emission-related instructions (or procedures developed by the operator that are approved by the engine manufacturer), change only those emission-related settings that are permitted by the manufacturer, and meet the requirements of 40 CFR 89, 94 and/or 1068, as they apply.</u>

<u>The operator shall comply with the emission standards specified in 40 CFR 60.4205(b) by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications.</u>

<u>[40 CFR 60 Subpart IIII, 1-30-2013]</u>

<u>[Devices subject to this condition: D25]</u>

I298.5 This equipment shall not be operated unless the facility holds ~~2412~~ <u>603</u> pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds ~~2412~~ <u>603</u> pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: D25]

K67.2 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

An engine operating log shall be maintained which on a monthly basis shall list all engine operations in each of the following areas:

A. Emergency use hours of operation,

B. Maintenance and testing hours, and

C. Other operating hours, with a description of the reason for operation.

In addition, each time the engine is started manually, the log shall include the date of operation and the timer reading in hours at the beginning and end of operation. The log shall be kept for a minimum of five calendar years prior to the current year and made available to District personnel upon request. The total hours of operation for the previous calendar year shall be recorded some time during the first 15 days of January each year.

[RULE 1110.2, ~~7-9-2010~~ **2-1-2008; RULE 1110.2, 9-7-2012; 40 CFR 60 Subpart IIII, 1-30-2013**]

[Devices subject to this condition: D25]

K67.3 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

The operator shall maintain records of diesel particulate filter inspections, replacements, and cleaning.

The operator shall maintain monthly records of the exhaust temperature, engine backpressure, and date and time for the duty cycle of the engine as downloaded from the HiBACK data logging and alarm system.

All records shall be maintained on file for a minimum of five years and made available to District personnel upon request.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; 40 CFR 60 Subpart IIII, 1-30-2013**]

[Devices subject to this condition: D25]

BACKGROUND

Existing Facility

Canyon Power Plant (CPP) is a natural gas-fired peaker power plant, nominally rated at 200 megawatts. The owner, SCPPA, is a consortium of municipalities and an irrigation district established by a Joint Powers Agreement to develop, construct, and operate electric generation and transmission projects. The City of Anaheim (COA), the sole participating member city, is the operator. The CPP is strictly dedicated for generating power to serve the COA's retail customers. CPP is RECLAIM and Title V, with the Title V term running from 3/23/10 to 3/22/15.

The CPP consists of (1) four identical General Electric LM6000PC Sprint combustion-turbine-generators (CTGs); (2) four identical selective catalytic reduction (SCR) systems and CO oxidation catalysts utilized for control of NOx and CO/VOC emissions, respectively; (3) one 10,000 gallon ammonia (NH_3) storage tank storing 19% aqueous ammonia which is part of the SCR process; (4) an 1141 bhp diesel emergency internal combustion engine (black start engine) used to start up the plant in the event of a loss of grid power; and (5) an oil water separator used to collect equipment washwater and rainfall. A 4-cell mechanical draft evaporative chiller cooling tower provides evaporative cooling for the inlet air to the CTGs to augment power production. The cooling tower is exempt from permitting pursuant to Rule 219(d)(3), which exempts water cooling towers not used for evaporative cooling of process water or not used for evaporative cooling of water from barometric jets or from barometric condensers and in which no chromium compounds are contained.

Permitting Background

On 12/28/07, SCPPA submitted an application for certification ("AFC") (07-AFC-9) to the CEC seeking certification for the new power plant. On 12/26/07, SCPPA submitted applications to the SCAQMD for permits to construct CPP, a new natural gas fired peaker power plant. The applications were A/Ns 476650 (Title V revision), -651, -654, -656, -657, -659, -660, -661, -663,- 665, -666, 481185, with A/N 476651 as the master file. The original scope required the access of PM_{10} priority reserve credits for the turbines from the Priority Reserve, which is governed by Rule 1309.1—Priority Reserve, amended August 3, 2007, because the facility-wide PM_{10} emissions would have been greater than 4 TPY. The VOC and SOx emissions from the turbines would have been exempt from offsets pursuant to the Rule 1304 offset exemption for facility-wide emissions of VOC and SOx less than 4 TPY. The black start engine would have been exempt from offsets pursuant to Rule 1304(a)(4) for emergency equipment.

Subsequently, the project underwent two major scope revisions to revise the operating schedule. The first scope change was made in response to the Superior Court's interim decision to enjoin the SCAQMD from implementing the 2007 amendment for Rule 1309.1—Priority Reserve. The second scope change was in response to the unavailability of any Rule 1304 offset exemptions, which was a development of the Court's decision. Consequently, the applicant was required to provide ERCs for all PM_{10}, VOC, and SOx emissions.

On 6/24/09, the Final Determination of Compliance (FDOC) was issued. On 3/17/10, the CEC certified the AFC. On 3/23/10, the P/Cs for CPP were issued. In a letter dated 7/29/11 regarding "California ISO Notification of Commercial Operation," Steve Sciortino, the then-responsible official, indicated that Turbines 3 and 4 successfully completed startup testing on 7/28/11. In a letter dated 9/15/11, Mr. Sciortino indicated that Turbines 1 and 2 successfully completed startup testing on 9/15/11. On 1/27/12, the facility submitted A/Ns 531827 (Title V revision), 531829 (master file), 531831-833. The purpose of the new applications was to revise condition A99.2 to increase the CO start-up emissions limit from 6.3 lb/hr to 11.6 lb/hr. On 6/14/12, the P/Cs with revised condition A99.2 were issued. On 9/20/12, the P/Os for the project were issued.

Pre-Project Major Source Status

The table below shows the pre-project potential-to-emit emissions for the facility and the major source thresholds for Title V and New Source Review (NSR). The pre-project facility is a major source for Title V and NSR. The pre-project potential to emit will be used to evaluate applicability for Rule 1303(b)(5)/Rule 2005(g), as well as applicability in Table 35—Rule 1325 Applicability and Table 37—Prevention of Significant Deterioration Applicability.

Table 1 - Pre-Project Major Source Status

Pollutant	**Major Source Threshold (TPY) For Title V and NSR**	**Pre-Project Facility Emissions—Commissioning Yr / Normal Operating Year**
NOx	10	20.56 tpy / 14.98 tpy
CO	50	14.40 tpy / 12.08 tpy
VOC	10	3.10 tpy / 3.10 tpy
PM_{10}	70	7.0 tpy / 7.18 tpy
SOx	100	0.80 tpy / 0.82 tpy

Source: Table 3—Major Source Applicability, on pg. 34 of FDOC.

Current Permits

The current permits are shown in the table below.

Table 2 - Current Permits to Operate

Equipment	Permit to Operate (A/N)	Device
Turbine No. 1	G20542 (A/N 531829, superseded A/N 476651)	D1, S6
Turbine No. 2	G20543 (A/N 531831, superseded A/N 476656)	D7, S12
Turbine No. 3	G20544 (A/N 531832, superseded A/N 476659)	D13, S18
Turbine No. 4	G20545 (A/N 531833, superseded A/N 476661)	D19, S24
SCR/CO Oxidation Catalyst No. 1	G20546 (A/N 476654)	C4, C3
SCR/CO Oxidation Catalyst No. 2	G20547 (A/N 476657)	C10, C9
SCR/CO Oxidation Catalyst No. 3	G20548 (A/N 476660)	C16, C15
SCR/CO Oxidation Catalyst No. 4	G20549 (A/N 476663)	C21, C22
Ammonia Storage Tank	G20550 (A/N 476665)	D28
Emergency ICE (Black Start Engine)	G20551 (A/N 476666)	D25
Oil Water Separator	G20552 (A/N 481185)	D29

Note: A/N 476651 (12 volumes) is the master file for the initial project, and includes a discussion of the condition A99.2 revision.

New Applications

Each turbine is currently permitted for 90 hours and 20 startups/shutdowns each month. In preparation for the projected increases in solar and wind generation and the anticipated loss of once-through-cooling power plants along the coast, the CAISO has imposed new operating requirements on peaking power plants to help mitigate these changes. Solar and wind power generation are unpredictable, and the output from these sources can change very rapidly depending on weather conditions.

The California Independent System Operator Flexible Resource Adequacy Criteria and Must Offer Obligation (FRAC-MOO) becomes effective January 1, 2015. To maintain system reliability, the CAISO will require load serving entities such as the CPP to provide a significant amount of flexible generation capacity to back up solar and wind generation as required. CAISO calls this type of flexible high ramp rate capacity "flexi-ramp" or "FRAC," and calls the load serving entity's must offer obligation "MOO." The CPP is capable of providing this type of FRAC-MOO capacity because it can reach full load in 10 minutes from a cold start (fast ramp rate) and the units can operate at a 42% minimum load and stand ready to ramp up to full load within a few minutes should clouds or lack of wind cause the output of solar and wind facilities, respectively, to decrease rapidly. Also, the CAISO expects two heavy ramping periods per day due to the amount of solar generation on the system when the renewable portfolio standards are fully implemented. That is, a plant like CPP would be scheduled on in the morning, off in the afternoon, and back on in the late afternoon/evening until loads drop off.

Canyon Power Plant was built to satisfy Anaheim's resource adequacy obligation as a load serving entity within the CAISO, and the proposed CEC permit modification is required to continue this purpose. The proposed 540 starts per year per unit allows three of the four Canyon units to meet the two starts per day FRAC-MOO requirement, and the increased annual NOx limit will provide 6-hour per day operation for Canyon to qualify under all three flexibility categories: base flexibility, peak flexibility, and super-peak flexibility. As the CPP's FRAC-MOO requirement is less than 150 MW, 540 starts per turbine (first annual operating scenario) will provide two starts per day for three of the four turbines thus satisfying the FRAC-MOO requirement. The 2,200 hours per year (first annual operating scenario) will satisfy the 6-hour per day requirement. The facility proposes to maintain the current language in the permit, which limits plant emissions and not run-hours because the plant may operate a significant amount of time at partial loads depending on system needs.

On 8/30/13, Karl Lany, SCEC, submitted the following applications on behalf of the facility. Subsequently, SCEC submitted three amendments to the applications as CAISO requirements evolved. New applications were not required because the facility provided sufficient notice to place the applications on hold and the changes related only to schedule.

Table 3 - New Applications

A/N	Prior Permit (A/N)	Equipment
555828	531829	Gas Turbine No. 1
555829	531831	Gas Turbine No. 2
555830	531832	Gas Turbine No. 3
555831	531833	Gas Turbine No. 4
555832	476666	Internal Combustion Engine, Emergency
555827		Title V/RECLAIM Significant Permit Revision

The changes proposed by the original applications and the three amendments are summarized below.

Applications--Original Scope, 8/30/13

1. Appendix A: NOx And SOx Emitting Equipment Exempt from Written Permit Pursuant To Rule 219
   Add ICEs rated at or below 50 bhp as reflected in past APEP submittals.

   On 7/16 and 7/17/14, RECLAIM AQAC Mitch Haimov was consulted regarding the criteria for adding equipment to Appendix A. The policy is that equipment should not be added unless they are existing or scheduled to be added in the near future. Contractor's equipment and rental equipment should not be included in the facility permit. The reporting requirements for rental equipment are set forth on Rule 2012, Appendix A, Chapter 1, pg. 2012A-1-2. On 7/17/14, Manny Robledo, Operations Manager, removed this request because no such engine is in operation or scheduled for near future installation.

2. Condition A63.1
   a. Re-evaluate monthly emission limits based on the following changes in the maximum monthly schedule.
      i. Increase normal operating hours from 90 to 160 hrs.
      ii. Increase startups/shutdowns from 20 to 22.
      iii. Add 10 hour for maintenance per year.

   b. Reduce PM_{10} emission factor for normal operations from 3.0 lb/hr to 1.67 lb/hr at maximum load to avoid the need to provide offsets for the increased operating schedule.

   c. Maintain PM_{10} monthly limit of 299 lb/calendar month, but increase VOC and SOx monthly limits in accordance with the increased monthly schedule.

3. Conditions A99.1 – A99.3
   a. Increase annual starts/shutdowns from 240/yr to 264/yr.

   b. Add maintenance operations to exemption from BACT requirements.

4. Conditions I298.1 – I298.4
   Increase NOx RTC holding requirements for turbines consistent with the increase in maximum operating hours per year (12 months times the proposed monthly maximum plus ten hours for maintenance).

5. Conditions C1.1
   Reduce black start engine operation from 200 hours to 50 hours.

6. Condition I298.5
   Reduce NOx RTC holding requirements for black start engine consistent with the reduction in operating hours.

On 11/5/13, Manny Robledo, Electric Operations Manager, requested that the project be placed on hold because the proposed schedule was in the process of being revised.

Amendment No. 1, 1/8/14
The amendment requested that the maximum monthly schedule be revised as follows, but the other proposed changes from 8/30/13 remain the same.

2. Condition A63.1
   a. Re-evaluate monthly emission limits based on the following changes in the maximum monthly schedule.
      i. Increase normal operating hours from 90 to 293.5 hours.
      ii. Increase startups/shutdowns from 20 to 22.
      iii. Add 10 hours for maintenance per year.

   c. Increase PM_{10} monthly limits.

On 2/26/14, Manny Robledo requested that the project be placed on hold because Canyon was in discussion with CAISO regarding the operating schedule.

Amendment No. 2, 6/5/14
The amendment requested that the maximum monthly schedule be revised again. The proposed maximum annual startups/shutdowns will now be less than 12 months times the number of startups/shutdowns per month. The other proposed changes from 8/30/13 remain the same.

2. Condition A63.1
   a. Re-evaluate monthly emission limits based on the following changes in the maximum monthly schedule.

      i. Increase normal operating hours from 90 to 280 hours.
      ii. Increase startups/shutdowns from 20 to 60.
      iii. Add 10 hours for maintenance per year.

3. Conditions A99.1 – A99.3
   a. Increase annual starts/shutdowns from 240/yr to 540/yr.

4. Conditions I298.1 – I298.4
   Increase NOx RTC holding requirements for turbines for the proposed annual operating schedule per turbine of 3400 normal operating hours, 540 startups/shutdowns, and 10 maintenance hours.

On 6/10/14, Karl Lany, SCEC, requested a hold because the proposed schedule will change again.

Amendment No. 3, 6/26/14

The amendment requested that the PM_{10} startup emissions be reduced and the maximum annual schedule be revised, but the other proposed changes from 8/30/13 remain the same.

2. Condition A63.1
   a. Re-evaluate monthly emission limits based on the following changes in the maximum monthly schedule. (Same as 6/5/14.)

      i. Increase normal operating hours from 90 to 280 hours.
      ii. Increase startups/shutdowns from 20 to 60.
      iii. Add 10 hours for maintenance per year.

   c. In revising the PM_{10} monthly limit in accordance with the monthly schedule, use the newly proposed decrease in startup emissions from 1.29 lb/event to 0.75 lb/event.

   d. Add annual emissions limits for VOC, PM_{10}, and SOx.

      Highest emissions from the two following profiles will be selected for each pollutant as annual emission limits. First annual operating profile: 2200 normal operating hours, 540 startups/shutdowns, and 10 maintenance hours. Second annual operating profile: 2674 normal operating hours, 365 startups/shutdowns, and 10 maintenance hours.

      The first profile results in higher annual CO emissions, and the second profile results in higher annual VOC, PM_{10}, and SOx emissions. Both yield the same annual NOx emissions.

3. Conditions A99.1 – A99.3
   a. Increase annual starts/shutdowns from 240/yr to 540/yr.

4. Conditions I298.1 – I298.4
   Increase NOx RTC holding requirements for turbines.

SOURCE TESTING

The original applications requested that the PM_{10} emission factor for normal operations set forth in condition A63.1 be reduced from 6.03 lb/mmcf (3.0 lb/hr at maximum load) that was based upon EPA AP-42 to 3.357 lb/mmcf (1.67 lb/hr at maximum load) to avoid the need to provide PM_{10} offsets for the proposed increase in the monthly and annual schedule. The proposed PM_{10} emission rate remained the same for the three subsequent amendments. (The proposed 3.357 lb/mmcf needs to be adjusted, because it assumes the 6.03 lb/mmcf in condition A63.1 was based solely on the 3.0 lb/hr. The 6.03 lb/mmcf was actually based on monthly emissions, including startups and shutdowns.)

On 6/26/13, the SCAQMD had issued permits to the City of Riverside Public Utilities Dept ("RPU") to modify existing turbines Nos. 3 (A/N 544562) and 4 (A/N 544563) located at its Riverside Energy Resource Center ("RERC") (ID 139796). The modifications included reducing the PM_{10} emission factor from 6.42 lb/mmcf (3.0 lb/hr max load) to 5.35 lb/mmcf (2.5 lb/hr max load) for two GE LM6000PC Sprint turbines (similar to the four turbines at CPP), as well as increasing the monthly and annual operating schedules. This PM_{10} emission factor change was supported by a memo by GE Energy entitled "PM10 Emissions from LM6000 for Mariposa Energy, LLC."

The GE memo provided a detailed technical analysis on PM_{10} emissions from the LM6000 gas turbines for the Mariposa Energy Project ("MEP") under the Bay Area AQMD (BAAQMD). The MEP, located in Liverpool, California, is a 200 MW simple cycle power plant consisting of four identical LM6000 PC-SPRINT gas turbines, similar to the turbines located at RERC and CPP. The project received the FDOC from the BAAQMD in November 2010, and approval of the AFC from the CEC on 5/18/11, with the facility beginning to produce power on 10/1/12.

In the memoranda, GE identifies the main sources of PM_{10} emissions from gas turbines fired on clean burning natural gas are:

- Formation of SO_3 from the sulfur in the fuel;
- Formation of ammonium sulfates from the ammonia in the SCR systems and the sulfur in the fuel;
- Particulate matter in the ambient air that gets pass the inlet air filtration systems;
- Contaminants in the water used for NOx control and power augmentation;
- Contaminants in the tempering air and other bypass air used for after-treatment purposes;
- Uncertainties in measurement system contributing to positive bias and variance.

GE analyzed PM_{10} data from a total of 42 source tests of LM6000 turbines permitted in the Bay Area. The variation in data was attributed to the variability in sulfur in the fuel, contaminants and particulates in the air and water, and testing uncertainty. After developing a statistical model to predict PM_{10} emissions and further analysis, GE arrived at the following conclusion:

"GE Emissions guarantees are based on 85% confidence interval with 97.5% pass rate. Based on these criteria and also taking other sources of variation into consider, it is our opinion that consistently testing PM10 emissions below 2.5 lb/hr cannot be achieved with certainty."

Since the proposed 1.67 lb/hr at max load for CPP is significantly lower than the 2.5 lb/hr at max load approved for RERC, existing source test results at CPP were reviewed and additional source tests were required to substantiate the 1.67 lb/hr at max load.

- ***Initial Source Test Results (2011)***
  The initial source test results for the four turbines at CPP were reviewed for PM to assess whether the proposed 1.67 lb/hr PM_{10} may be feasible.

  The initial source test protocol for the four turbines, dated 3/17/11, had been prepared by Delta Air Quality Services. The proposed test method for measuring PM was SCAQMD Method 5.1. In an evaluation, dated 4/19/11, Sr. Source Test Engineer Mike Cecconi concluded the protocol was "conditionally acceptable," with no deficiencies noted. Initial source test condition D29.1 required PM_{10} testing at 100% load only.

  Turbine Nos. 3 and 4
  On June 11-13, 2011, Advanced Environmental Compliance (AEC) performed the initial source testing on Turbine Nos. 3 and 4. (Delta was not available.) Source test reports for each turbine were issued 7/5/11. In an evaluation dated 8/18/11, Mike Cecconi concluded the source test report for the two units was "conditionally acceptable," with no deficiencies noted for PM_{10}.

  Turbine Nos. 1 and 2
  On August 9-11, 2011, Delta Air Quality Services, Inc. performed the initial source testing on Turbine No. 2, and on August 12-14, 2011, the testing for Turbine No. 1. Separate source test reports for each turbine were issued 9/12/11. In an evaluation dated 2/10/12, Mike Cecconi concluded the source test report for Turbine No. 1 was "acceptable" for PM_{10}. In an evaluation dated 2/10/12, Mike Cecconi concluded the source test report for Turbine No. 2 was "acceptable" for PM_{10}.

  The initial source test results for particulate matter for the four turbines are summarized in the table below. The results for Turbine Nos. 3 and 4 (AEC) range from 2.07 to 2.15 lb/hr PM. The results for Turbine Nos. 1 and 2 (Delta) were both 1.48 lb/hr PM. The lower Delta results appear to be credible because Delta has been working on improving QA/QC and keeping their equipment clean. Since the Delta results of 1.48 lb/hr PM are lower than the proposed 1.67 lb/hr PM_{10}, the next step is to evaluate and/or perform additional source tests on the turbines.

Table 4 - Initial Source Test Results for Particulate Matter For Turbines 1 – 4 (2011)

Turbine	Parameter	100% Load	Current Condition A63.1
No. 3	PM (SCAQMD Method 5.1)	2.07 lb/hr	6.03 lb/mmcf based on **3.0 lb/hr PM_{10} at max load** and startups/shutdowns
No. 4	PM	2.15 lb/hr	
No. 1	PM	1.48 lb/hr	
No. 2	PM	1.48 lb/hr	

- ***Additional Source Testing to Evaluate Proposed 1.67 lb/hr PM_{10}***
  Since the applicant requested that the PM_{10} emission factor be determined by the end of 2013 to allow the purchase of PM_{10} ERCs in early 2014, the evaluation of the proposed 1.67 lb/hr PM_{10} was extensively discussed with Sr. Source Test Engineer Mike Cecconi and expedited.

  Turbine Nos. 3 and 4 (2012)
  A survey of existing source test reports was conducted to assess whether the 1.67 lb/hr PM_{10} can be supported. The most relevant source testing had been performed by Delta on November 13-14, 2012 on Turbine Nos. 3 and 4 at CPP. Delta had performed a set of informational tests on the two turbines, including for total particulate using SCAQMD Method 5.1, and PM_{10} using EPA Method 201A/SCAQMD Method 5.1. Method 201A separates particulate matter less than 10 μm from the flue gas using a cyclone of an EPA approved design. The source test report was issued on 12/4/12. The purposes of the tests were to compare the two source test methods and to support a more representative PM_{10} emission factor.

  The source test report was submitted to the Source Testing Dept for evaluation of the proposed limit of 1.67 lb/hr PM_{10} at maximum load.

  In an e-mail dated 9/25/13, Mike Cecconi recapped his discussion with Matt McCune, Delta, regarding these source tests. One clarification provided by Mr. McCune was that Delta used the same equipment as is used in other PM tests. However, Delta scrupulously ensured the cleanliness of the sampling equipment and used more precise weighing to enable an extra digit to be used with the weight readings.

  In an evaluation dated 9/26/13, Mike Cecconi concluded the source test report for the two units was "conditionally acceptable." The PM_{10} reported emissions may be used for compliance determination and emission calculations provided the emission calculations are used with the noted cautions. The following comments were made regarding the Representativeness of Data & Process.

  - Each unit had a run conducted according to Method 5.1 (measuring total PM) and a run conducted according to EPA Method 201A (measuring PM_{10}). One of the reasons for the testing was to compare the results of the two methods. This round of testing was not for compliance testing. It should be noted that Gas Turbines No. 1-4 are identical units.

- Reported PM_{10} sample catches were very low (<5 mg) despite the fact that most of the test runs lasted 240 minutes per run (the Method 5.1 run for Unit 3 lasted only 168 minutes). The tester said that the sample sizes were so low that the results were approaching the statistical "noise" of the methods. The tester declined to estimate what the absolute accuracy of the PM_{10} measurements would be at these sample sizes. However, it should be noted that the grain loadings (grains/dscf) and the emission rates (lb/hr) were relatively consistent for all the runs.

- The tester was asked if he knew any reason why the PM_{10} emissions were considerable lower for this round of tests than they were during the initial source tests in 2011. While the tester could not point to any specific process conditions that could indicate possibly lower PM_{10} emission rates, he noted that when Delta initially tested Turbine Nos. 1 and 2 in 2011, there was dust in the air due to ongoing construction surrounding the turbines although there was no construction on the turbines themselves. He also noted that for the initial tests, the impinger water had a pale brown tinge that is not usual for PM_{10} testing of natural gas-fired units. Thus the dust in the air could have added to the PM_{10} in the samples, but the tester had no way to determine the exact source that caused the pale brown tinge.

The following comment was made regarding the Sampling & Analytical Methods/Results.

- Due to equipment problems during the Method 5.1 test for Unit 3, the test could not be conducted over four hours as the other tests were conducted. Instead, each of the 24 traverse points were sampled for seven minutes apiece for a total sampling time of 168 minutes instead of the usual 240 minutes of sampling conducted during the other test runs. PM_{10} tests should run for 240 minutes because of the small amount of PM_{10} that gas-fired turbine emit. However, the grain loadings (grains/dscf) and the emission rates (lb/hr) for this run matched well with the amount collected during the other runs. Thus, this run should not be penalized or disregarded because of the 168-minute sample time.

The source test results for PM and PM_{10} for the Turbine Nos. 3 and 4 are summarized in the table below.

Table 5 -Source Test Results For PM And PM_{10} For Turbines 3 And 4 (2012)

Turbine	Parameter	100% Load	Proposed PM_{10} Limit ("Emissions and Requirements" Column)
No. 3	PM (SCAQMD Method 5.1)	0.66 lb/hr	1.67 lb/hr at maximum load
	PM_{10} (EPA Method 201A)	0.55 lb/hr	
No. 4	PM	0.40 lb/hr	
	PM_{10}	0.48 lb/hr	

Turbine Nos. 1 and 2 (2013)
Additional data were required to assess whether the proposed 1.67 lb/hr PM_{10} can be supported. To that end, the applicant was requested to have Turbine Nos. 1 and 2 source tested according to a new approved protocol that will include testing for PM and PM_{10}.

A source test protocol for PM and PM_{10} testing for the two turbines, dated 9/27/13, was prepared by Delta. The proposed test method for measuring PM was SCAQMD Method 5.1 and PM_{10} by EPA Method 201A/SCAQMD Method 5.1. In an evaluation, dated 10/10/13, Mike Cecconi concluded the protocol was "conditionally acceptable," with no deficiencies noted. The following source test method deviation was approved.

- Usually three runs per unit are required when using Method 210A/5.1 in compliance tests. However, since the Method 210A/5.1 test results will be used to confirm the Method 5.1 test results in this round of testing, one Method 201A/5.1 test run per each Method 5.1 run will be sufficient. Three Method 201A/5.1 runs per unit will be required for future PM_{10} compliance tests.

On October 22-23, 2013, Delta performed the PM and PM_{10} source testing on Turbine Nos. 1 and 2, with the source test report issued 11/6/13. The source test report was submitted to the Source Testing Dept for evaluation of the proposed limit of 1.67 lb/hr PM_{10} at maximum load. In an evaluation dated 11/20/13, Mike Cecconi concluded the source test report was "conditionally acceptable." The PM_{10} reported emissions may be used for compliance determination and emission calculations provided the emission calculations are used with cautions.

The three comments regarding the Representativeness of Data & Process are almost identical to the three comments made for the source testing of Turbine Nos. 3 and 4 discussed above.

The source test results for PM and PM_{10} for the Turbine Nos. 3 and 4 are summarized in the table below.

Table 6 - Source Test Results For PM And PM_{10} For Turbines 1 And 2 (2013)

Turbine	Parameter	100% Load	Proposed PM_{10} Limit ("Emissions and Requirements" Column)
No. 1	PM (SCAQMD Method 5.1)	0.44 lb/hr	1.67 lb/hr at maximum load
	PM_{10} (EPA Method 201A)	0.42 lb/hr	
No. 2	PM	0.42 lb/hr	
	PM_{10}	0.83 lb/hr	

<u>Source Testing Conclusions for PM_{10} Emission Rates</u>

1. <u>Decrease PM_{10} emission rate for normal operations</u>
   Sr. Source Testing Engineer Mike Cecconi concluded that the source testing for PM and PM_{10} for the four turbines in 2012 and 2013 performed to support the proposed decrease in the PM_{10} emission rate from 3.0 lb/hr at maximum load to 1.67 lb/hr at maximum load are "conditionally acceptable." The results range from 0.40 lb/hr – 0.83 lb/hr, which are conservatively 24% - 50% of the proposed 1.67 lb/hr. Consequently, emissions calculations will be based on 1.67 lb/hr, and that limit will be added to the "Emissions and Requirements" with a rule tag of Rule 1303(b)(2)—Offsets.

   The source testing frequency in condition D29.3 will be increased. This condition currently requires PM_{10} source testing at least once every three years. The condition will be revised to require testing for PM and PM_{10} at least once every 18 months in order to verify compliance with the emission rate of 1.67 lb/hr at maximum load during normal operations. These source tests shall be conducted using the protocol dated September 27, 2013 and approved by the SCAQMD on October 10, 2013. Protocol approval indicated three Method 210A/5.1 runs per unit will be required for future compliance tests. If all tests conducted over a three-year period comply with the 1.67 lb/hr limit, the facility shall have the option of reducing the source test frequency to once every three years.

2. <u>Decrease PM_{10} emission rate for startups</u>
   Karl Lany, SCEC, provided the following reasoning for decreasing the PM_{10} startup emissions rate from 1.29 lb/startup to 0.75 lb/startup in the same ratio as the decrease from 3.0 lb/hr to 1.67 lb/hr for normal operations.

   Mr. Lany reviewed Table 13--Revised Turbine Startup Sequence for a Normal 35–Minute Startup Event, Turbine Trip, Purge for 5 Minutes, then Restart, found on pg. 52 of the FDOC. The table shows the startup emissions profile and the derivation of the 1.29 lb/startup rate. He also reviewed the startup emission curve that GE provided in the AFC, found in the Appendix to Section 6. His review indicated the two sources generally complement each other and indicate a reliance on a constant default emission factor and fuel consumption rate to determine PM_{10} emissions for each minute of the startup event.

The two sources show that the lb/minute and lb/hr PM_{10} emission rates steadily increase as fuel consumption rates and accumulated fuel consumption increase. In both cases, the emission factor levels out once fuel consumption rates hit steady 100% load. The primary difference between the two sources is that the initial AFC documentation suggests a faster startup period but was subsequently replaced with the 35-minute startup period requested by the applicant for the FDOC. Both sources, however, include a leveling out of full-load emissions at a rate of 3.01 lb/hr, which reflects the initially assumed default PM_{10} emission rate of approximately 6.3 lb/mmbtu. All available information suggests that there is no difference in the lb/hr rate between minute #1 and minute #35 of operation.

The above analysis confirms the reasonable assumption that GE based the start-up emissions on the same default emission rate as used for normal operations. As SCAQMD-approved source tests have demonstrated that the normal operations emission rate can be reduced from 3.0 lb/hr at maximum load to 1.67 lb/hr at maximum load, the start-up emissions rate of 1.29 lb/startup can be reduced by the same ratio to 0.75 lb/startup. The new start-up emissions is calculated as follows: [(1.29 lb/startup) * (1.67 lb/hr / 3.0 lb/hr) = 0.72 lb/startup]. The applicant requested a more conservative 0.75 lb/startup, but not a reduction in the shutdown emissions of 0.18 lb/hr. Based on the above analysis, the PM_{10} startup emissions will be reduced from 1.29 lb/startup to 0.75 lb/startup.

If the facility is unable to demonstrate sustained compliance with the 1.67 lb/hr limit and the limit is required to be increased, the start-up emissions will be increased proportionately.

PROCESS DESCRIPTION

1. **Turbine Nos. 1-4**

   a. **Turbines Pre-Modification A/N 531829, 531831, 531832, 531833**

   The four simple cycle CTGs are natural gas-fired General Electric LM6000PC Sprint Combustion Turbine Generators, rated at 50.95 MW. The CTGs are equipped with evaporative inlet air cooling and water injection into the combustion zone. The inlet combustion air is cooled via a chiller cooling tower system to increase turbine performance during high ambient temperature conditions. The CTGs have water injection spray evaporative inter-cooling between the low-pressure and high- pressure compressor sections as well as to the inlet of the low-pressure compressor to increase turbine performance.

   The water injection into the combustor also suppresses flame temperature and reduces the 1-hour average NOx concentration to 25 ppmvd at 15% oxygen prior to entry into the SCR. The SCR catalyst with ammonia injection further reduces the NOx emissions to

2.3 ppmv, 1-hour average, dry basis at 15% O2, which is lower than the 2.5 ppmv BACT limit.

A/N 476654, 476657, 476660, 476663—Selective Catalytic Reduction (SCR)/CO Oxidation Catalyst Systems Nos. 1-4
Each CTG is equipped with a selective catalytic reduction/CO oxidation catalyst system.

The CO oxidation catalyst, located between the CTG and the SCR, is used to control CO and VOC emissions. The catalyst reduces CO emissions to 4 ppmv and the VOC to 2 ppmv, both 1-hour averages, dry basis at 15% O_2.

The SCR catalyst uses ammonia injection in the presence of the catalyst to further reduce the NOx concentration in the exhaust gases. Diluted ammonia vapor is 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 at no greater than 2.3 ppmv at 15% O_2 on a 1-hour average. The ammonia slip will be limited to 5 ppmvd at 15% O_2. Each SCR will be vented through a dedicated stack, which is 11.7 ft diameter and 86 ft high.

b. Turbines—Post-Modification A/N 555828, 555829, 555830, 555831

The turbines and process are not proposed to be changed. These applications are modification applications, because the emissions will increase due to the proposed increases in the operating schedule.

As the SCR/CO oxidation catalyst systems will not be modified, applications were not required.

2. Emergency Internal Combustion Engine

a. ICE—Pre-Change A/N 476666

The ICE, Caterpillar, Model C-27, rated at 1141 BHP and fired on diesel, serves as a black start engine. The black start engine is used only in emergency situations where grid power from the COA's 69 kV system is unavailable to start the CTGs. The black start engine provides power to the turbine starter motors. Once the turbines are started and begin providing power to the grid, the black start engine is shut down. The engine is controlled by a diesel particulate filter (DPF), CleanAIR Systems, Inc. PERMIT™, Model FDA225, as a DPF is required by LAER.

Condition C1.1 limits operating time to no more than 200 hours in any one year with no more than 50 hours for maintenance and performance testing, which are standard requirements for emergency engines.

Condition C1.1 also limits the duration of each test to 38 minutes in any one hour. For the FDOC, although the black start engine is exempt from air quality modeling due to Rule 1304(a)(4), modeling was required by the CEC for CEQA compliance. Although the BACT limit of 4.8 g/bhp-hr, or 12.06 lb/hr, is used to calculate the required number of RTCs, the certified emission rate of 4.08 g/bhp-hr, or 10.27 lb/hr, was used for the modeling pursuant to CEC guidance. The engine may be tested at the 10.27 lb/hr rate for up to 38 minutes in any hour without causing an exceedance of the California one-hour NO_2 standard. Consequently, condition no. C1.1 limited the duration of maintenance tests for this engine to 38 minutes in any one hour.

b. <u>ICE—Post-Change A/N 555832</u>

The equipment is not proposed to be changed.

The application proposes to revise condition C1.1 to reduce the operating time limit from 200 hours to 50 hours in any one year. The reason is to reduce the number of NOx RTCs required to be held by condition I298.5.

The applicant explained that only 50 hours is required because the black start engine will only be used to start the power plant in case of a regional blackout and then it will be turned off after the plant is carrying load and generating electricity. The emergency engine is used to power the administration building, control systems, CEMS, turbine auxiliary pumps, balance of plant pumps, and emission control equipment, but it will not be used to provide backup power over an extended period of time. Since the facility tests the unit for an hour once a month, that leaves 38 hours for use during a system blackout. System blackouts have occurred very infrequently in the past, because CPP is connected directly to the Anaheim sub-transmission system through two redundant transformers. Therefore, the probability of a distribution power outage at the plant is extremely low.

Condition C1.1 continues to limit testing to 38 minutes in any one hour. The engine was not modeled for this project because the operating hours will be decreased and because emergency engines are exempt from modeling pursuant to Rule 1304(a)(4).

<u>EMISSIONS CALCULATIONS</u>

1. <u>Turbine Nos. 1-4</u>

The four identical CTGs emit combustion emissions consisting of criteria pollutants, toxic pollutants, and greenhouse gases.

A. <u>CRITERIA POLLUTANTS</u>

a. <u>Pre-Modification--A/N 531829, 531831, 531832, 531833</u>

The emissions calculations are found in A/N 476651, 476656, 476659, and 476661 (master file), the initial applications for CPP. The emissions calculations did not change for the subsequent applications, A/N 531829, 531831, 531832, 531833, which revised Condition No. A99.2 to increase the start-up emissions limit from 6.3 lb/hr to 11.60 lb/hr. The 30-day average for CO did not change because it is dependent on the CO emissions for a 35-minute start-up event (no change), not the maximum hourly start-up emissions (increase from 6.3 lb/hr to 11.6 lb/hr).

The emissions calculations for normal operations are presented below to allow comparison with post-modification calculations. Commissioning emissions are not discussed in detail because the 30-day averages for commissioning and normal operations are the same.

- ***Pre-Modification Startup and Shutdown Emissions per Turbine***
  The startup and shutdown emissions and duration are shown in the table below.

Table 7 – Pre-Modification Startup and Shutdown Emissions and Duration, per CTG

Pollutants	Startup, lbs/event	Shutdown, lbs/event	Startup Duration	Shutdown Duration
NOx	10.09	0.69	35 minutes	10 minutes
CO	4.10	0.62		
VOC	0.79	0.27		
PM_{10}	1.29	0.18		
SOx at 0.25 gr/100 dscf	0.14	0.02		

Source: Table 17—Startup and Shutdown Emissions, per CTG, on pg. 57 of FDOC.

- ***Pre-Modification Maximum Daily Emissions per Turbine***
  Maximum daily emissions during normal operations were calculated to determine whether the emissions increases will trigger BACT/LAER requirements.

  To determine the worst case operating scenario that yields the highest controlled emissions for normal operation, the applicant provided nine 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 nine scenarios (cases) were provided in the "Revised Permit to Construct/Permit to Operate Application for the Canyon Power Plant," dated September 2008, in Table 3-2 (Revised)—1-Hour Operating Emission Rates and Stack Parameters for Individual CTG Operating Load Scenarios on pg 3-3, supplemented by the "Turbine Operating Scenarios" tables in Appendix B. The normal operating emission rates were from **Case 4**, which was identified as the worst case operating scenario. On April 21, 2009, the applicant submitted minor corrections to the controlled NOx hourly emissions rates. (For details, see Table 9—Operating Scenarios and Table 10—Worst Case Operating Scenarios for Normal Operation on pages 46-47 of FDOC.)

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

Table 8 - Pre-Modification Maximum Daily Emissions, per CTG

Pollutants	No. of Normal Operating Hrs	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shutdowns	lb/shutdown	Maximum Daily Emissions lb/day
NOx	22.5	3.98	2	10.09	2	0.69	**111.11**
CO	22.5	4.24	2	4.10	2	0.62	**104.84**
VOC	22.5	1.2	2	0.79	2	0.27	**29.12**
PM_{10}	22.5	3.00	2	1.29	2	0.18	**70.44**
SOx	22.5	0.34	2	0.14	2	0.02	**7.97**

Source: Table 18—Maximum Daily Emissions, per CTG, on pg. 58 of FDOC.

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

- ***Pre-Modification Maximum Monthly Emissions and Emission Factors per Turbine***

  The maximum monthly emissions calculations for normal operations are shown in the table below. The applicant had requested that the maximum VOC, SOx, and PM_{10} in any one month during the commissioning period not exceed the maximum emissions during a normal operating month.

  The calendar monthly limits per turbine for VOC, PM_{10}, and SOx for both normal operations and the commissioning period set forth in existing condition A63.1 were from this table. As the commissioning has been completed, the emission factors will be removed.

Table 9 - Pre-Modification Maximum Monthly Emissions, Normal Operations, per CTG

Pollutants	No. of Normal Operating Hrs	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shutdowns	lb/shutdown	Maximum Monthly Emissions lb/month
NOx	90	3.98	20	10.09	20	0.69	**573.80**
CO	90	4.24	20	4.10	20	0.62	**476.00**
VOC	90	1.2	20	0.79	20	0.27	**129.20**
PM_{10}	90	3.00	20	1.29	20	0.18	**299.40**
SOx	90	0.34	20	0.14	20	0.02	**33.80**

Source: Table 20—Maximum Monthly Emissions, Normal Operations, per CTG, on pg. 59 of FDOC.

Maximum Monthly Emissions, lb/day = (no. normal operating hours) (normal emission rate) + (no. startups) (lb/startup) + (no. shutdowns) (lb/shutdown)

- ***Pre-Modification Maximum Annual Emissions for Each Turbine***
  The maximum normal operating year emissions for each turbine are shown in the table below.

Table 10 – Pre-Modification Maximum Annual Emissions, Normal Operating Year, with Emissions Factors, per CTG

Pollutants	Maximum Annual Emissions, lb/yr	Emission Factors, lb/mmcf
NOx	(573.80 lb/month) * (12 months) = 6885.6 lb/yr (3.44 tpy)	
CO	(476 lb/month) * (12 months) = 5712 lb/yr (2.86 tpy)	
VOC	(129 lb/month) * (12 months) = 1548 lb/yr (0.77 tpy)	2.59
PM_{10}	(299 lb/month) * (12 months) = 3588 lb/yr (1.79 tpy)	6.03
SOx	(34 lb/month) * (12 months) = 408 lb/yr (0.20 tpy)	0.68

Source: Table 23—Maximum Annual Emissions, Normal Operating Year, with Emissions Factors, per CTG, on pg. 61 of FDOC.

The table above also shows the normal operating emission factors, which are required to be included in condition nos. A63.1 for VOC, PM_{10}, and SO_X.

Emission Factor, lbs/mmcf = (lbs/yr) x (yr/1260 hrs) x (2.11 hr/mmcf)

The 2.11 hr/mmcf is calculated as 913 Btu/scf (LHV) / 433.6 MMBtu/hr (LHV), with both values provided by the applicant.

- ***Pre-Modification Maximum Annual Emissions for Project***
  The maximum normal operating year emissions for the facility are shown in the table below.

Table 11 - Pre-Modification Maximum Annual Facility/Project Emissions, Normal Operating Year

Equipment	NO_x, lb/yr	CO, lb/yr	VOC, lb/yr	PM_{10}, lb/yr	SO_x, lb/yr	CO_2e, tpy
Turbine No. 1	6885.6	5712	1548	3588	408	35,337.48
Turbine No. 2	6885.6	5712	1548	3588	408	35,337.48
Turbine No. 3	6885.6	5712	1548	3588	408	35,337.48
Turbine No. 4	6885.6	5712	1548	3588	408	35,337.48
Total for Four Turbines	27,542.4	22,848	6192	14,352	1632	141,349.92
Ammonia Tank	0	0	0	0	0	
Emergency ICE, Black Start Engine	2412	1306	10	10.8	2.46	30.22
Oil Water Separator	0	0	0	0	0	
Total for Project	29,954.40 (14.98 tpy)	24,154 (12.08 tpy)	6202 (3.10 tpy)	14,362.8 (7.18 tpy)	1634.46 (0.82 tpy)	141,380.14 tpy

Source: Table 27--Maximum Annual Facility/Project Emissions, Normal Operating Year, on pg. 73 of FDOC, except for CO_2e. CO_2e emissions are from Table 26 below.

- ***Pre-Modification Actual Emissions***
  As discussed in the *Rule Evaluation* section below, recent actual pre-project emissions will be used to evaluate applicability in Table 35—Rule 1325 Applicability, and Table 37—Prevention of Significant Deterioration Applicability.

Table 12 – Pre-Modification Actual Emissions for Canyon Power Plant for 2011 and 2012

	CO	NOx	PM_{10}	$PM_{2.5}$	ROG	SOx	CO_2e
Year	**Tons/Year**						
2011	5.67	10.57	1.21	1.21	0.61	0.18	23,499.65
2012	7.74	4.51	3.09	3.09	1.32	0.35	61,672.48
2-yr Average	6.71	7.54	2.15	2.15	0.97	0.27	42,586.0

CO, NOx, PM, ROG, and SOx reported emissions from Facility Information Detail (FIND). (Applicant also provided the Annual Emission Reports for 2011 and 2012).
PM emissions are from four turbines, black start engine, and Rule 219 exempt cooling tower.
Assume PM = PM_{10} = $PM_{2.5}$.

CO_2e emissions for turbines are from the GHG Summary Reports for Part 75 reporting. CO2e emissions for engine are provided by SCEC.

2011: [(21313.3 metric tons CO_2e/yr reported for turbines)(2204.6 lb/metric ton)(tons/2000 lbs)] + (6 tons for engine) = 23,499.65 tpy

2012: [(55948 metric tons CO_2e/yr reported for turbines)(2204.6 lb/metric ton)(tons/2000 lbs)] + (1 ton for engine) = 61,672.48 tpy

- ***Pre-Modification Offset Requirements, NSR Entries, ERCs/RTCs***
  Offset Requirements
  The pre-modification offset requirements, as applicable to the FDOC, are described below.

  VOC, SOx, and PM_{10}
  Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant from a new or modified source to be offset unless exempt from offset requirements pursuant to Rule 1304. "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." Rule 1304(d)(1)(A) provides, in part, that any new facility that has a potential to emit less than 4 tons per year for VOC, SOx, or PM_{10} shall be exempt from offsets for those pollutants that are under the threshold. As discussed above, Rule 1304 exemptions were not available because of the Superior Court decision. Therefore, CPP was required to provide emission reduction credits (ERCs) for all increases in emissions from permitted equipment, based on a 30-day average, for these pollutants.

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 applicant had requested that the emissions for the commissioning month be no higher than the emissions for a normal operating month. The offset ratio for emission reduction credits (ERCs) is 1.2-to-1. The applicant was required to hold the required amount of ERCs before the Permits to Construct were issued. As discussed above, priority reserve credits (PRCs) were not available because of the court decision on Rule 1309.1.

CO
Since CO is an attainment pollutant and is not a precursor to any nonattainment pollutant, offsets were not required.

NOx
The facility had opted into RECLAIM. Rule 2205(b)(2) requires a new facility to sufficient RTCs to offset the total facility emissions for the first year of operation, at a 1-to-1 ratio. Specifically, equipment shall not be operated unless the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. Further, the equipment shall not be operated unless at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase. Thus, the emissions during the initial commissioning year (9677 pounds) and the emissions during subsequent normal operating years (6886 pounds) were required to be calculated to determine the number of RTCs required.

NSR Entry Calculations
The NSR entries were calculated for each turbine, as follows.

Operating Schedule
Operating Schedule: 52 wks/yr, 7 days/wk, 24 hrs/day to annualize the emissions.

The maximum monthly emissions for each turbine are from Table 9 above (same as Table 20 in FDOC).

NO_x
Actual controlled = 2.3 ppm = 3.98 lb/hr (normal operation)
Actual uncontrolled = 25 ppm with water injection = 43.64 lb/hr
(provided by Express Integrated Technologies)

To calculate control efficiency:
Control efficiency = [(43.64 – 3.98)/43.64] x 100% = 90.88%

To calculate R2:
30-DA = (573.80 lb/month, Table 9) (month/30 days) = 19.13 lb/day
Lb/hr = (19.13 lb/day) (day/24 hr) = 0.80 lb/hr

To calculate R1:
Lb/day, uncontrolled = (19.13 lb/day) / (1- 0.9088) = 209.76 lb/day
Lb/hr, uncontrolled = (209.76 lb/day) (day/24 hr) = 8.74 lb/hr

CO
Actual controlled = 4.0 ppm = 4.24 lb/hr (normal operation)
Actual uncontrolled = 53 ppm (provided by Express Integrated Technologies) = 56.18 lb/hr

To calculate control efficiency:
Control efficiency = [(56.18 – 4.24)/56.18] x 100% = 92.45%

To calculate R2:
30-DA = (476 lb/month, Table 9) (month/30 days) = 15.87 lb/day
Lb/hr = (15.87 lb/day) (day/24 hr) = 0.66 lb/hr

To calculate R1:
Lb/day, uncontrolled = (15.87 lb/day) /(1-0.9245) = 210.20 lb/day
Lb/hr, uncontrolled = (210.20 lb/day) (day/24 hr) = 8.76 lb/hr

ROG
Actual controlled = 2.0 ppm = 1.2 lb/hr (normal operation)
Actual uncontrolled = 3 ppm (provided by Express Integrated Technologies) = 1.8 lb/hr

To calculate control efficiency:
Control efficiency = [(1.8 – 1.2)/1.8] x 100% = 33.33%

To calculate R2:
30-DA = (129.2 lb/month, Table 9) (month/30 days) = 4.31 lb/day
Lb/hr = (4.31 lb/day) (day/24 hr) = 0.18 lb/hr

To calculate R1:
Lb/day, uncontrolled = (4.31 lb/day) /(1-0.3333) = 6.46 lb/day
Lb/hr, uncontrolled = (6.46 lb/day) (day/24 hr) = 0.27 lb/hr

PM_{10}
Actual controlled = Actual uncontrolled = 3 lb/hr (normal operation)

To calculate R2 and R1:
30-DA = (299.4 lb/month, Table 9) (month/30 days) = 9.98 lb/day
Lb/hr = (9.98 lb/day) (day/24 hr) = 0.42 lb/hr

$\underline{SO_x}$
Actual controlled = Actual uncontrolled = 0.34 lb/hr (normal operation)
(based on 0.25 gr/100 scf average natural gas sulfur content)

To calculate R2 and R1:
30-DA = (33.8 lb/month, Table 9) (month/30 days) = 1.13 lb/day
Lb/hr = (1.13 lb/day) (day/24 hr) = 0.047 lb/hr

Emissions Update: On 10/14/14, Sr. Engineer John Yee updated the 30-day averages in the NSR database for A/N 531829, 531831, 531832, 531833 for the four turbines to match the 30-day averages shown above.

CO: Updated from 15.84 lb/day to 15.87 lb/day.
NOx: Updated from 19.20 lb/day to 19.13 lb/day
PM_{10}: Updated from 10.08 lb/day to 9.98 lb/day
ROG: Updated from 4.32 lb/day to 4.31 lb/day.
SOx: Updated from 1.20 lb/day to 1.13 lb/day.

Offsets/RTCs Required for Project

The following table shows the offsets/RTCs required for the pre-modification project.

Table 13 - Pre-Modification Offsets/RTCs Required for Project

A/N	Equipment	VOC 30-Day Avg, lbs/day	VOC ERCs, lbs/day	SOx 30-Day Avg, lbs/day	SOx ERCs, lbs/day	PM_{10} 30-Day Avg, lbs/day	PM10 ERCs, lbs/day	NOx RTCs for Commissioning/ Normal Operating Yr
476651	Turbine No. 1	4.31	6	1.13	2	9.98	12	9677/6886
476656	Turbine No. 2	4.31	5	1.13	1	9.98	12	9677/6886
476659	Turbine No. 3	4.31	5	1.13	1	9.98	12	9677/6886
476661	Turbine No. 4	4.31	5	1.13	1	9.98	12	9677/6886
476654	SCR/CO Oxidation Catalyst No. 1	0	0	0	0	0	0	0
476657	SCR/CO Oxidation Catalyst No. 2	0	0	0	0	0	0	0
476660	SCR/CO Oxidation Catalyst No. 3	0	0	0	0	0	0	0
476663	SCR/CO Oxidation Catalyst No. 4	0	0	0	0	0	0	0
476665	Ammonia Tank	0	0	0	0	0	0	0
481185	Oil Water Separator	0	0	0	0	0	0	0
476666	Emergency ICE, black start engine	0.01	0	0	0	0.01	0	2412/2412
	Total Project	17.25		4.52		39.93		41,120/29,956
	1.2 offset factor	20.69		5.42		47.92		
	ERCs Required	**21**	**21**	**5**	**5**	**48**	**48**	

Source: Table for 30-Day Aves on pg 74 of FDOC, and Table 40A--ERCs and RTCs Required on pg. 100 of FDOC.

b. Post-Modification A/N 555828, 555829, 555830, 555831

- ***Post-Modification Startup and Shutdown Emissions per Turbine***

  For the modification, the startup and shutdown emissions and duration are shown in the table below. One, the PM_{10} startup emissions will decrease from 1.29 lb/event to 0.75 lb/event, pursuant to recent SCAQMD-approved source testing. Two, the CO startup emissions will be conservatively corrected from 4.10 lb/startup to 11.6 lb/startup. When application numbers 531829, 531831-833 were approved to revise condition A99.2 to increase the CO start-up emissions limit from 6.3 lb/hr to 11.6 lb/hr, the lb/startup was not increased from 4.10 lb/startup to 11.6 lb/startup at that time. The reasons were that startups only take 35 minutes, the exceedances above the 4.10 lb/startup were rare, and the exceedances appeared to primarily be caused by limitations of the CO/O2 analyzers and CEMS/DAHS systems. As the new applications are conservatively based on 11.6 lbs/start-up, the start-up emissions will be changed accordingly.

Table 14 – Post-Modification Startup and Shutdown Emissions, per CTG

Pollutants	Startup, lbs/event	Shutdown, lbs/event	Startup Duration	Shutdown Duration
NOx	10.09	0.69	35 minutes	10 minutes
CO	~~4.10~~ **11.60**	0.62		
VOC	0.79	0.27		
PM_{10}	~~1.29~~ **0.75**	0.18		
SOx at 0.25 gr/100 dscf	0.14	0.02		

- ***Post-Modification Maximum Daily Emissions per Turbine***

  For the modification, the PM_{10} normal operation emission rate will decrease from 3.00 lb/hr to 1.67 lb/hr, and the PM_{10} startup emission rate will decrease from 1.29 lb/event to 0.75 lb/event. The CO startup emission rate will increase from 4.10 lb/event to 11.6 lb/event.

Table 15 - Maximum Daily Emissions, per CTG

Pollutants	No. of Normal Operating Hrs	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shutdowns	lb/shutdown	Maximum Daily Emissions lb/day
NOx	22.5	3.98	2	10.09	2	0.69	111.11
CO	22.5	4.24	2	~~4.10~~ **11.60**	2	0.62	~~104.84~~ **119.84**
VOC	22.5	1.2	2	0.79	2	0.27	29.12
PM_{10}	22.5	~~3.00~~ **1.67**	2	~~1.29~~ **0.75**	2	0.18	~~70.44~~ **39.44**
SOx	22.5	0.34	2	0.14	2	0.02	7.97

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

- ***Post-Modification Maximum Monthly Emissions and Emission Factors per Turbine***

For the modification, the number of normal operating hours will increase from 90 to 280 hours, the number of startups/shutdowns will increase from 20 to 60, the PM_{10} normal operation emission rate and the PM_{10} startup emissions will decrease, and 10 hours of maintenance will be added.

During the maintenance period, the emissions may not be fully controlled as the tuning and testing of the emission control systems are performed. To account for the worse case, emission rates are based on uncontrolled emission rates for the full ten hours. As discussed above, the controlled emissions rates were from Case 4 of the nine cases provided in the "Turbine Operating Scenarios" tables in Appendix B of the "Revised Permit to Construct/Permit to Operate Application for the Canyon Power Plant," dated September 2008. For the maintenance period, the uncontrolled emissions rates for NOx, CO, and VOC will be from Case 4 of the same tables. For PM_{10} and SOx, the uncontrolled emission rates are equal to controlled emission rates.

The table below shows the maintenance emission rate limits for conditions A99.1 – A99.3 (NOx, CO, VOC), and the maintenance emission factors for condition A63.1 (VOC, PM10, SOx).

Table 16 - Maintenance Operations, Uncontrolled Emissions

Pollutants	Concentration, ppm at 15% O_2	Maintenance Emission Rates, lb/hr, for Conditions A99.1 – A99.3	Maintenance Emission Factors, lb/mmcf, for Condition A63.1
NOx	25	44	
CO	18	19.40	
VOC	2	1.25	2.64
PM_{10}		1.67	3.52
SOx		0.34	0.72

Emission Factor, lbs/mmcf = (lb/hr) x (2.11 hr/mmcf from FDOC)

The table below shows the maximum monthly emissions, which will be based on 335 total hours, consisting of 280 normal operating hours, 60 startups and shutdowns, and 10 hours of maintenance.

Table 17 - Post-Modification Maximum Monthly Emissions, Normal Operations, per CTG

Pollutants	No. of Normal Operating Hrs	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shutdowns	lb/shutdown	Total Maximum Emissions, Not Including Maintenance	Normal Operation Emission Factors, lbs/mmcf, For A63.1	No. of Hours for Maintenance	Uncontrolled Emission Rate for Maintenance lb/hr	Total Maximum Monthly Emissions lb/month
NOx	~~90~~ 280	3.98	~~20~~ 60	10.09	~~20~~ 60	0.69	1761.20		10	44.00	~~573.80~~ 2201.20
CO	~~90~~ 280	4.24	~~20~~ 60	~~4.10~~ 11.60	~~20~~ 60	0.62	1920.40		10	19.40	~~476.00~~ 2114.40
VOC	~~90~~ 280	1.2	~~20~~ 60	0.79	~~20~~ 60	0.27	399.60	2.59	10	1.25	~~129.20~~ 412.10
PM_{10}	~~90~~ 280	~~3.00~~ 1.67	~~20~~ 60	~~1.29~~ 0.75	~~20~~ 60	0.18	523.40	3.40	10	1.67	~~299.40~~ 540.10
SOx	~~90~~ 280	0.34	~~20~~ 60	0.14	~~20~~ 60	0.02	104.80	0.68	10	0.34	~~33.80~~ 108.20

Maximum Monthly Emissions, lb/month = (no. normal operating hours) (controlled normal emission rate) + (no. startups) (lb/startup) + (no. shutdowns) (lb/shutdown) + (no. maintenance hours) (uncontrolled normal emission rate)

Emission Factor, lbs/mmcf = (lb/month) (month/325 hr) x (2.11 hr/mmcf)

From the table above, the monthly limits in condition A63.1 will be increased to VOC, 412 lb/month; PM_{10}, 540 lb/month; and SOx, 108 lb/month. For normal operations, including startups and shutdowns but not maintenance, the emission factors for VOC and SOx will remain unchanged, but the PM_{10} emission factor will decrease from 6.03 lb/mmcf to 3.40 lb/mmcf.

- ***Post-Modification Maximum Annual Emissions for Each Turbine***

  The maximum annual emissions for each pollutant will be based on the higher of the emissions from the two annual operating profiles proposed by the applicant. The two operating profiles were selected to result in the same number of NOx RTCs required. The maximum monthly emissions are determined based on the summer months when electric power demand is high. However, the same high demand is not required the rest of the year. The 30-day averages and the number of ERCs, unless exempt by Rule 1304, are determined by the maximum monthly emissions. The number of RTCs, however, is based on maximum annual emissions. The maximum annual emissions are 12 times the maximum monthly emissions unless annual limits are set by permit conditions. The facility is requesting less than 12 times the maximum monthly emissions in order to limit the number of RTCs required.

  The maximum annual emissions from the first annual operating profile (2615 total hours, consisting of 2200 normal operating hours, 540 startups/shutdowns, and 10 maintenance hours), are shown below.

Table 18 - Post-Modification Maximum Annual Emissions, Normal Operations, per CTG
First Annual Operating Profile

Pollutants	No. of Normal Operating Hrs	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shutdowns	lb/shutdown	No. of Hours for Maintenance	Uncontrolled Emission Rate for Maintenance lb/hr	Maximum Annual Emissions lb/yr
NOx	2200	3.98	540	10.09	540	0.69	10	44.00	15,017.20
CO	2200	4.24	540	11.60	540	0.62	10	19.40	16,120.80
VOC	2200	1.2	540	0.79	540	0.27	10	1.25	3,224.90
PM_{10}	2200	1.67	540	0.75	540	0.18	10	1.67	4,192.90
SOx	2200	0.34	540	0.14	540	0.02	10	0.34	837.80

Maximum Annual Emissions, lb/year = (no. normal operating hours) (controlled normal emission rate)
+ (no. startups) (lb/startup) + (no. shutdowns) (lb/shutdown) + (no. maintenance hours) (uncontrolled normal emission rate)

The maximum annual emissions from the second annual operating profile (2958 total hours consisting of 2674 normal operating hours, 365 startups/shutdowns, and 10 maintenance hours), are shown in the table below.

Table 19 - Post-Modification Maximum Annual Emissions, Normal Operations, per CTG
Second Annual Operating Profile

Pollutants	No. of Normal Operating Hrs	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shutdowns	lb/shutdown	No. of Hours for Maintenance	Uncontrolled Emission Rate for Maintenance lb/hr	Maximum Annual Emissions lb/yr
NOx	2674	3.98	365	10.09	365	0.69	10	44.00	15,017.22
CO	2674	4.24	365	11.60	365	0.62	10	19.40	15,992.06
VOC	2674	1.2	365	0.79	365	0.27	10	1.25	3,608.20
PM_{10}	2674	1.67	365	0.75	365	0.18	10	1.67	4,821.73
SOx	2674	0.34	365	0.14	365	0.02	10	0.34	970.96

The following table compares the emissions and operating schedule for the two profiles and presents the maximum annual emissions for each pollutant and the maximum annual operating schedule.

Table 20 – Post-Modification Maximum Annual Emissions/Schedule Comparison of the Two Annual Operating Scenarios

Pollutants	First Annual Operating Scenario, lb/yr	First Annual Operating Scenario Schedule	Second Annual Operating Scenario, lb/yr	Second Annual Operating Scenario Schedule	Higher of Two Annual Operating Scenarios, lb/yr	Higher of Two Annual Operating Scenarios, Schedule
NOx	**15,017.20**	2615 total hrs, consisting of 2200 normal operating hrs, 540 startups/shutdowns, 10 maintenance hrs	**15,017.22**	2958 total hrs, consisting of 2674 normal operating hrs, 365 startups/shutdowns, 10 maintenance hrs	**15,017.22**	**2958 total hrs, 540 startups/shutdowns, 10 maintenance hrs.**
CO	**16,120.80**		15,017.22		**16,120.80**	
VOC	3,224.90		**3,608.20**		**3,608.20**	
PM_{10}	4,192.90		**4,821.73**		**4,821.73**	
SOx	837.80		**970.96**		**970.96**	

Annual limits for VOC, PM_{10}, and SOx will be added to condition A63.1 because the annual emissions will no longer be 12 times the monthly limits. The annual emissions limits will be VOC, 3608 lb/yr; PM_{10}, 4822 lb/yr; and SOx, 971 lb/yr. For conditions I298.1 – I298.4, the number of RTCs will increase from 6886 lbs to 15,017 lbs. (The 9677 lb for the commissioning year will be removed.) For conditions A99.1 – A99.3, the number of startups will be increased from 240 to 540.

The facility has requested that there not be a limit on annual hours because the turbines may operate at partial loads. Limits on the maximum annual emissions for VOC, PM_{10}, and SOx will be added to condition A63.1 for the following reasons. Annual toxics emissions are based on 2958 total hours. Annual greenhouse gas emissions are based on the second annual operating schedule (2958 total hours). The dispersion modeling for annual NO_2 and $PM_{10}/PM_{2.5}$ are based on the second annual operating scenario. Maximum annual emissions for the turbines are included in Table 21—Post-Modification Maximum Annual Facility Emissions. The maximum facility emissions for SO_2 and PM_{10} from Table 21 will be used to determine applicability in Table 35—Rule 1325 Applicability, and Table 37—Prevention of Significant Deterioration Applicability.

- ***Post-Modification Maximum Annual Emissions for the Facility***
  The maximum annual emissions for the facility are shown in the table below. NOx, CO, VOC, PM_{10} and SOx emissions per turbine are from Table 20 above, and CO_2e is from Table 27 below. (The black start engine calculations for criteria pollutants, toxic pollutants, and greenhouse gases are shown later in this section.)

Table 21 - Post-Modification Maximum Annual Facility Emissions

Equipment	NO_x, lb/yr (tpy)	CO, lb/yr (tpy)	VOC, lb/yr (tpy)	PM_{10}, lb/yr (tpy)	SO_x, lb/yr (tpy)	CO2e, tpy
Turbine No. 1	15,017.22 (7.51 tpy)	16,120.80 (8.06 tpy)	3,608.20 (1.80 tpy)	4,821.73	970.96	83,081.44
Turbine No. 2	15,017.22	16,120.80	3,608.20	4,821.73	970.96	83,081.44
Turbine No. 3	15,017.22	16,120.80	3,608.20	4,821.73	970.96	83,081.44
Turbine No. 4	15,017.22	16,120.80	3,608.20	4,821.73	970.96	83,081.44
Total for Turbines	**60,068.88**	**64,483.20**	**14,432.80**	**19,286.92**	**3883.84**	**332,325.76**
Ammonia Tank (no change)	0	0	0	0	0	0
Emergency ICE, Black Start Engine	603.00	326.50	2.50	2.70	0.62	30.22
Oil Water Separator (no change)	0	0	0	0	0	0
Total for Facility	**60,671.88 (30.34 tpy)**	**4,809.70 (32.40 tpy)**	**14,435.30 (7.22 tpy)**	**19,289.62 (9.64 tpy)**	**3884.46 (1.94 tpy)**	**332,355.98 tpy**

The table below shows the annual emission increases for the facility. The project increase for PM_{10} and NOx emissions are used in the applicability analyses for Rules 1303(b)(5)(C) and 2005(g)(4)--Protection of Visibility.

Table 22 – Post-Modification Increase in Annual Emissions from Facility

Pollutants	Pre-Project Annual Emissions, lb/yr (tpy)	Post-Project Annual Emissions, lb/yr (tpy)	Increase in Emissions, lb/yr (tpy)
NOx	29,954.40 (14.98 tpy)	60,671.88 (30.34 tpy)	30,717.48 (15.36 tpy)
CO	24,154 (12.08 tpy)	64,809.70 (32.40 tpy)	40,655.70 (20.32 tpy)
VOC	6202 (3.10 tpy)	14,435.30 (7.22 tpy)	8233.30 (4.12 tpy)
PM_{10}	14,362.8 (7.18 tpy)	19,289.62 (9.64 tpy)	4926.82 (2.46 tpy)
SOx	1634.46 (0.82 tpy)	3884.46 (1.94 tpy)	2250.00 (1.12 tpy)
CO_2e	141,380.14 tpy	332,355.98 tpy	190,975.84 tpy

- ***Post-Modification NSR Entries***

The NSR entries are calculated below for each turbine.

Operating Schedule

Operating Schedule: 52 wks/yr, 7 days/wk, 24 hrs/day to annualize the emissions.

The maximum monthly emissions for each turbine are from Table 17 above.

NO_x

Actual controlled = 2.3 ppm = 3.98 lb/hr (normal operation)
Actual uncontrolled = 25 ppm with water injection = 44 lb/hr (GE Vendor Data, Case 4)

To calculate control efficiency:
Control efficiency = [(44.00 – 3.98)/44.00] x 100% = 90.95%

To calculate R2:
30-DA = (2201.2 lb/month, Table 17) (month/30 days) = 73.37 lb/day
Lb/hr = (73.37 lb/day) (day/24 hr) = 3.06 lb/hr

To calculate R1:
Lb/day, uncontrolled = (73.37 lb/day) / (1 – 0.9095) = 810.72 lb/day
Lb/hr, uncontrolled = (810.72 lb/day) (day/24 hr) = 33.78 lb/hr

CO

Actual controlled = 4.0 ppm = 4.24 lb/hr (normal operation)
Actual uncontrolled = 18 ppm = 19.4 lb/hr (GE Vendor Data, Case 4)

To calculate control efficiency:
Control efficiency = [(19.4 – 4.24)/19.4] x 100% = 78.14%

To calculate R2:

30-DA = (2114.40 lb/month, Table 17) (month/30 days) = 70.48 lb/day
Lb/hr = (70.48 lb/day) (day/24 hr) = 2.94 lb/hr

To calculate R1:
Lb/day, uncontrolled = (70.48 lb/day) /(1 – 0.7814) = 322.42 lb/day
Lb/hr, uncontrolled = (322.42 lb/day) (day/24 hr) = 13.43 lb/hr

<u>*ROG*</u>
Actual controlled = 2.0 ppm = 1.20 lb/hr (normal operation)
Actual uncontrolled = 2 ppm = 1.25 lb/hr (GE Vendor Data, Case 4)
To calculate control efficiency:
Control efficiency = [(1.25 – 1.2)/1.25] x 100% = 4%

To calculate R2:
30-DA = (412.10 lb/month, Table 17) (month/30 days) = 13.74 lb/day
Lb/hr = (13.74 lb/day) (day/24 hr) = 0.57 lb/hr

To calculate R1:
Lb/day, uncontrolled = (13.74 lb/day) /(1 – 0.04) = 14.31 lb/day
Lb/hr, uncontrolled = (14.31 lb/day) (day/24 hr) = 0.60 lb/hr

<u>*PM_{10}*</u>
Actual controlled = Actual uncontrolled = 1.67 lb/hr (normal operation)

To calculate R2 and R1:
30-DA = (540.10 lb/month, Table 17) (month/30 days) = 18.00 lb/day
Lb/hr = (18.00 lb/day) (day/24 hr) = 0.75 lb/hr

<u>*SO_x*</u>
Actual controlled = Actual uncontrolled = 0.34 lb/hr (normal operation)
(based on 0.25 gr/100 scf average natural gas sulfur content)

To calculate R2 and R1:
30-DA = (108.20 lb/month, Table 17) (month/30 days) = 3.61 lb/day
Lb/hr = (3.61 lb/day) (day/24 hr) = 0.15 lb/hr

- <u>***Project Daily Emissions Increases***</u>
  The following table summarizes daily emissions increased for the project, which will be used in Table 28—Rule 212(c)(2) Applicability, and Table 39--Significant Permit Revision Applicability.

Table 23—Post-Modification Daily Emissions Increases for Project (30-Day Averages)

A/N	Equipment	VOC 30-Day Average, lbs/day	SOx 30-Day Average, lbs/day	PM_{10} 30-Day Average, lbs/day	CO 30-Day Average, lbs/day	NOx 30-Day Average, lbs/day
555828	Turbine No. 1	13.74 – 4.31 = 9.43	3.61 - 1.13 = 2.48	18.00 - 9.98 = 8.02	70.48 – 15.87 = 54.61	73.37 – 19.13 = 54.24
555829	Turbine No. 2	9.43	2.48	8.02	54.61	54.24
555830	Turbine No. 3	9.43	2.48	8.02	54.61	54.24
55531	Turbine No. 4	9.43	2.48	8.02	54.61	54.24
555832	Emergency ICE, black start engine	0	0	0	0	0
	Total Project	37.72 (0.019 tpy)	9.92 (0.005 tpy)	32.08 (0.016 tpy)	218.44 (0.109 tpy)	216.96 (0.108 tpy)

- ***Project 30-Day Averages***
  The following table summarizes the 30-day averages for the project, which will be used to calculate the required offsets in the Rule 1303(b)(2) analysis below.

Table 24 - Post-Modification Project 30-Day Averages

A/N	Equipment	VOC 30-Day Average, lbs/day	SOx 30-Day Average, lbs/day	PM_{10} 30-Day Average, lbs/day
555828	Turbine No. 1	13.74	3.61	18.00
555829	Turbine No. 2	13.74	3.61	18.00
555830	Turbine No. 3	13.74	3.61	18.00
55531	Turbine No. 4	13.74	3.61	18.00
555832	Emergency ICE, black start engine	Emergency equipment exempt from offsets per Rule 1304(a)(4).		
	Total Project, lbs/day	54.96 lb/day	14.44 lb/day	72.00 lb/day

B. TOXIC POLLUTANTS

a. Pre-Modification--A/N 531829, 531831, 531832, 531833

The pre-modification risk assessment for Rule 1401 was based on 1260 hr/yr for each turbine. Emission factors for all toxic pollutants, except ammonia, formaldehyde, benzene, acrolein, and speciated PAHs, were from USEPA AP-42 Table 3.1-3 for uncontrolled natural gas-fired stationary turbines. Formaldehyde, benzene, and acrolein emission factors were from the background document for AP-42 Section 3.1, Table 3.4-1 for a natural gas-fired combustion turbine with a CO catalyst. Speciated PAH emissions and hexane (no AP-42) were from the California Air Toxics Emission Factors (CATEF) database for natural gas-fired combustion turbines with SCR and CO catalyst. The ammonia emissions levels were from the turbine manufacturer.

b. Post-Modification A/N 555828, 555829, 555830, 555831

The post-modification risk assessment will be based on 2958 hrs/yr for each turbine (second annual operating profile). Based on current District policy, emission factors for all toxic pollutants, except ammonia, are from USEPA AP-42 Table 3.1-3 for uncontrolled natural gas-fired stationary turbines. The ammonia emission level is from the turbine manufacturer. Ammonia is a toxic air contaminant for the purpose of Rule 1401, but not a federal hazardous air pollutant.

The toxic emissions are shown in the table below.

Table 25 - Toxic Air Contaminants per Turbine

Pollutant	CAS	Emission Factor (lb/MMBtu)	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)	Annual Emission Rate (tons/yr)	Emission Factor Source
Acetaldehyde	75070	4.00E-05	1.92E-02	5.67E+01	2.84E-02	AP-42
Acrolein	107028	6.40E-06	3.07E-03	9.08E+00	4.54E-03	AP-42
Ammonia	7664417		3.64	1.08E+04	5.40E+00	Vendor Data Case 4 (Highest)
Benzene	71432	1.20E-05	5.75E-03	1.70E+01	8.51E-03	AP-42
Butadiene, 1,3-	106990	4.30E-07	2.06E-04	6.09E-01	3.05E-04	AP-42
Ethylbenzene	100414	3.20E-05	1.53E-02	4.53E+01	2.27E-02	AP-42
Formaldehyde	50000	7.10E-04	3.40E-01	1.01E+03	5.00E-01	AP-42
Naphthalene	91203	1.30E-06	6.23E-04	1.84E+00	9.21E-04	AP-42
Total PAHs (other than naphthalene)		9.00E-07	4.31E-04	1.28E+00	6.38E-04	AP-42
Propylene Oxide	75569	2.90E-05	1.39E-02	4.11E+01	2.06E-02	AP-42
Toluene	108883	1.30E-04	6.23E-02	1.84E+02	9.20E-02	AP-42
Xylenes	1330207	6.40E-05	3.07E-02	9.07E+01	4.54E-02	AP-42
Total Annual HAP Emissions per Turbine, TPY					**7.2E-01**	

The hourly and annual emissions are calculated as follows:

Hourly emissions, lb/hr = (Emission Factor) (479 MMBtu/hr)

Annual emissions, lb/yr = (Emission Factor) (479 MMBtu/yr * 2958 hrs/yr)

C. GREENHOUSE GASES (GHG)

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

a. Pre-Modification A/N 531829, 531831, 531832, 531833

As GHG emissions were not required to be calculated in 2009 for the FDOC, they will be calculated here.

Emission factors for CO_2, CH_4, and N_2O are from Emission Factors for Greenhouse Gas Inventories, revised April 4, 2014, Table 1—Stationary Combustion Emission Factors, for fuel type natural gas.

For <u>each</u> turbine:

CO_2: 53.06 kg CO_2/MMBtu

CH_4 : 1 g CH_4/MMBtu

N_2O: 0.10 g N_2O/MMBtu

Annual heat input/turbine = [12 months/yr] [(90 hr normal operation/month) + (20 start-ups) (35 min/startup) (hr/60 min) + (20 shutdowns) (10 min/start-up) (hr/60 min)] * [479 MMBtu/hr] = 1260 hrs/yr * 479 MMBtu/hr = 603,540 MMBtu/yr

CO_2 = (603,540 MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
= 70,559,740.91 lb/yr = 35,299.87 tpy

CH_4 = (603,540 MMBtu/yr)(1 g/MMBtu)(2.205×10^{-3} lb/g)
= 1330.81 lb/yr = 0.67 tpy

N_2O = (603,540 MMBtu/yr)(0.1 g/MMBtu)(2.205×10^{-3} lb/g)
= 133.08 lb/yr = 0.07 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 = (35,299.87 tpy CO_2)(1 lb CO_2e/lb CO2) + (0.67 tpy CH_4)
(25 lb CO2e/lb CH_4) + (0.07 tpy N_2O)(298 lb CO_2e/lb N_2O)
= 35,337.48 tpy per turbine

Table 26 – Pre-Modification Greenhouse Gases for Facility

	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
Turbine No. 1	35,299.87	0.67	0.07	35,337.48
Turbine No. 2	35,299.87	0.67	0.07	35,337.48
Turbine No. 3	35,299.87	0.67	0.07	35,337.48
Turbine No. 4	35,299.87	0.67	0.07	35,337.48
Black Start Engine	30.11	0.00125	0.00025	30.22
Facility	141,229.59	2.68	0.28	141,380.14

b. <u>Post-Modification A/N 555828, 555829, 555830, 555831</u>
Based on the second annual operating profile—

Annual heat input/turbine = [(2674 hr normal operation/yr) + (365 start-ups) (35 min/startup) (hr/60 min) + (365 shutdowns) (10 min/start-up) (hr/60 min) + 10 hr maintenance] * [479 MMBtu/hr] = 2957.75 hr/yr * 479 MMBtu/hr = 1,416,762.25 MMBtu/yr

Emission factors for CO_2, CH_4, and N_2O are from Emission Factors for Greenhouse Gas Inventories, revised April 4, 2014, Table 1—Stationary Combustion Emission Factors, for fuel type natural gas.

For <u>each</u> turbine:

CO_2 = (1,416,762.25 MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
= 165,727,288.6 lb/yr = 82,863.64 tpy

For NSR entry, calculate lb/hr based on annualized schedule of 52 wk/yr, 7 days/wk, 24 hr/day:
(165,727,288.6 lb/yr)(yr/52 wk)(wk/7 days)(days/24 hrs) = 18,970.61 lb/hr

CH_4 = (1,416,762.25 MMBtu/yr)(1 g/MMBtu)(2.205×10^{-3} lb/g)
= 3123.96 lb/yr = 1.56 tpy

For NSR entry:
(3123.96 lb/yr)(yr/8736 hr) = 0.36 lb/hr

N_2O = (1,416,762.25 MMBtu/yr)(0.1 g/MMBtu)(2.205×10^{-3} lb/g)
= 312.40 lb/yr = 0.6 tpy

For NSR entry:
(312.40 lb/yr)(yr/8736 hr) = 0.04 lb/hr

CO_2e = (82,863.64 tpy CO_2)(1 lb CO_2e/lb CO2) + (1.56 tpy CH_4)
(25 lb CO2e/lb CH_4) + (0.6 tpy N_2O)(298 lb CO_2e/lb N_2O)
= 83,081.44 tpy per turbine

Table 27 – Post-Modification Greenhouse for Facility

	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
Turbine No. 1	82,863.64	1.56	0.6	83,081.44
Turbine No. 2	82,863.64	1.56	0.6	83,081.44
Turbine No. 3	82,863.64	1.56	0.6	83,081.44
Turbine No. 4	82,863.64	1.56	0.6	83,081.44
Black Start Engine	30.11	0.00125	0.00025	30.22
Facility	331,484.67	6.24	2.40	332,355.98

2. **<u>Black Start Emergency Internal Combustion Engine</u>**
   A. **<u>CRITERIA POLLUTANTS</u>**
      a. **<u>Pre-Change A/N 476666</u>**
      Operating schedule: 50 wk/yr, 1 day/wk, 1 hr/day

For non-RECLAIM pollutants, this engine would have been exempt from offset requirements per Rule 1304(a)(4), which exempts a source exclusively used as emergency standby equipment, if it were not for the Superior Court decision. The 30-day averages from the engine were included in the project emissions to determine project offsets for VOC, PM_{10}, and SOx. Because the NSR rules in Regulation XIII do not specify a basis for the operating schedule, the District policy is to use 50 hours of operation.

For NOx, the RECLAIM rules do not provide an offset exemption. 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. Therefore, the number of RTCs required was based on 200 hours based on condition C1.1. Emergency internal combustion engines are limited by District rules to 200 hours.

<u>NOx</u>
NOx, uncontrolled = NOx, controlled

According to RECLAIM Engineer Susan Tsai, RECLAIM allows the use of the BACT limit for the emission factor without requiring source testing for confirmation, but not the District certified emission level (4.08 g/bhp-hr for this engine). BACT for NOx + ROG is 4.8 g/bhp-hr. As BACT for only NOx is not provided, the entire 4.8 g/bhp-hr was used as the emission factor.

NOx, lb/hr = (1141 bhp) (4.8 g/bhp-hr BACT) (lb/454 g) = 12.06 lb/hr
lb/day = (12.06 lb/hr) (1 hr/day) = 12.06 lb/day
30-DA = (12.06 lb/day) (1 day/wk x 4.33 /30 days) = 1.75 lb/day (NSR Data Summary Sheet)

Number of RTCs required:
Condition I296.2 (now I298.5) specified the RTCs required for the commissioning year and subsequent normal operating years, which are the same.

RTCs required each year = (12.06 lb/hr) (200 hours) = 2412 lb/yr

<u>CO</u>
CO, uncontrolled = CO, controlled.

CO, lb/hr = (1141 bhp) (2.6 g/bhp-hr BACT) (lb/454 g) = 6.53 lb/hr
lb/day = (6.53 lb/hr) (1 hr/day) = 6.53 lb/day
30 DA = (6.53 lb/day) (1 day/wk x 4.33 /30 days) = 0.95 lb/day (NSR Data Summary Sheet)

<u>VOC</u>
VOC, uncontrolled = VOC, controlled
Use certified emission factor of 0.02 g/bhp-hr, because the BACT limit is for NOx + ROG.

VOC, lb/hr = (1141 bhp) (0.02 g/bhp-hr per certification) (lb/454 g) = 0.050 lb/hr
lb/day = (0.050 lb/hr) (1 hr/day) = 0.050 lb/day
30 DA = (0.050 lb/day) (1 day/wk x 4.33 /30 days) = 0.01 lb/day (NSR Data Summary Sheet)

<u>PM_{10}</u>
The diesel particulate filter is CARB certified for 85% reduction.

- <u>Uncontrolled</u>
  PM_{10}, lb/hr = (1141 bhp) (0.15 g/bhp-hr PM BACT) (0.96 PM_{10}/PM) (lb/454 g) = 0.36 lb/hr
  lb/day = (0.36 lb/hr) (1 hr/day) = 0.36 lb/day

- <u>Controlled</u>
  PM_{10}, lb/hr = (0.36 lb/hr) (1-0.85 control) = 0.054 lb/hr
  lb/day = (0.054 lb/hr) (1 hr/day) = 0.054 lb/day
  30 DA = (0.054 lb/day) (1 day/wk x 4.33 /30 days) = 0.01 lb/day (NSR Data Summary Sheet)

<u>SOx</u>
SOx, uncontrolled = SOx, controlled

SO_x, lb/hr = (1141 bhp) (0.0049 g/bhp-hr for 15 ppmw fuel) (lb/454 g)
= 0.012 lb/hr
lb/day = (0.012 lb/hr) (1 hr/day) = 0.012 lb/day
30 DA = (0.012 lb/day) (1 day/wk x 4.33 /30 days) = 0 lb/day (NSR Data Summary Sheet)

b. <u>Post-Change A/N 555832</u>
Operating schedule: 50 wk/yr, 1 day/wk, 1 hr/day

Post-change emissions are the same as pre-change, except there will be a reduction in the number of RTCs required.

Condition I298.5 sets forth the RTCs required for each year. Condition C1.1 will limit operation to 50 hours.

RTCs required each year = (12.06 lb/hr) (50 hours) = 603 lb/yr

B. <u>TOXIC POLLUTANTS</u>

a. <u>Pre-Change A/N 476666</u>
Although the black start engine was exempt from modeling pursuant to Rules 1304(a)(4), which exempts standby equipment, CEQA required modeling for the total facility. The District modeling staff's evaluation of the air quality modeling protocol stated the risks of the diesel-fired black start engine are determined by its particulate

emissions, and the VOC and particulate emissions from the black start engine are not to be speciated.

The HRA used a particulate emission rate of 0.33 lbs/hr, provided by the manufacturer based on the BACT limit of 0.15 g/bhp-hr (Tier 2), with an 85% control efficiency from the filter.

PM_{10}, lb/yr = (0.33 lbs/hr) (1 – 0.85) (200 hr) = 9.9 lb/yr

Note: Diesel particulate is not a federal HAP.

b. Post-Change A/N 555832

Operating schedule: 50 wk/yr, 1 day/wk, 1 hr/day

Diesel PM = PM_{10}, lb/yr = (0.33 lbs/hr) (1 – 0.85) (50 hr) = 2.48 lb/yr = .0012 tpy

C. GREENHOUSE GASES (GHG)

a. Pre-Change A/N 476666

Combustion of natural gas in the black start engine results in emissions of CO_2, CH_4, and N_2O.

Emission factors for CO_2, CH_4, and N_2O are from Emission Factors for Greenhouse Gas Inventories, revised April 4, 2014, Table 1—Stationary Combustion Emission Factors, for fuel type Distillate Fuel Oil No. 2.

CO_2: 10.21 kg CO_2/gallon
CH_4: 0.41 g CH_4/gallon
N_2O: 0.08 g N_2O/gallon

Fuel consumption at full load = 53.5 gal/hr (Caterpillar Diesel Generator Set Standby 750 ekW 937 kVA)

CO_2, lb/hr = (10.21 kg/gallon)(53.5 gal/hr)(2.2046 lb/kg) = 1204.23 lb/hr
lb/yr = (1204.23 lb/hr) (50 hr/yr) = 60,211.50 lb/yr = 30.11 tpy

CH_4, lb/hr = (0.41 g/gallon)(53.5 gal/hr)(2.205 x 10^{-3} lb/g) = 0.05 lb/hr
lb/yr = (0.05 lb/hr) (50 hr/yr) = 2.50 lb/yr = 0.00125 tpy

N_2O, lb/hr = (0.08 g/gallon)(53.5 gal/hr)(2.205 x 10^{-3} lb/g) = 0.01 lb/hr
lb/yr = (0.01 lb/hr) (50 hr/yr) = 0.50 lb/yr = 0.00025 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.

$$CO_2e = (30.11 \text{ tpy } CO_2)(1 \text{ lb } CO_2e/\text{lb } CO2) + (0.00125 \text{ tpy } CH_4)$$
$$(25 \text{ lb } CO2e/\text{lb } CH_4) + (0.00025 \text{ tpy } N_2O)(298 \text{ lb } CO_2e/\text{lb } N_2O) = 30.22 \text{ tpy}$$

b. <u>Post-Change A/N 555832</u>
Operating schedule: 50 wk/yr, 1 day/wk, 1 hr/day

Emissions are the same as pre-change.

<u>RULE EVALUATION</u>

The turbines and black start engine are expected to comply with all applicable SCAQMD rules and regulations, and federal and state regulations, as follows:

<u>DISTRICT RULES AND REGULATIONS</u>
<u>Rule 212—Standards for Approving Permits</u>
<u>Rule 2005(h) –Public Notice for RECLAIM</u> *<u>(requires compliance with Rule 212)</u>*
Public notice **<u>is</u>** required for this project, as discussed below.

- ***Rule 212(c)(1)***
  Public notice is required for any new or modified permit unit, source under Regulation XX (RECLAIM), or 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.

  Although the turbine emissions will increase, this subsection does **not** require public notice because the turbines are **not** be located within 1000 feet of the outer boundary of a school. The nearest K-12 school—Valadez Middle School Academy, 161 East La Jolla Street, Placentia, CA 92870--is located 0.5 miles (2640 ft) away, according to www.greatschools.org.

- ***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 project will exceed the daily maximum thresholds set forth in subdivision (g) for NOx, VOC and PM_{10}, as shown below. The increase in 30-day averages are from Table 23.

Table 28 - Rule 212(c)(2) Applicability

	NOx, lb/day	CO, lb/day	VOC, lb/day	PM_{10}, lb/day	SOx, lb/day	Lead, lb/day
Increase in 30-day averages, lb/day	216.96	218.44	37.72	32.08	9.92	0
Rule 212(c)(2) Daily Maximum, lbs/day	40	220	30	30	60	3
Increase Exceed Daily Maximum?	Yes	No	Yes	Yes	No	No

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 the Anaheim Central Library located at 500 W. Broadway, Anaheim, CA 92805 during the 30-day comment period: (1) public notice, (2) project information submitted by the applicant, and the (3) District's permit 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 (Orange County Register).

Pursuant to (g)(3), the public notice will be mailed to the following persons: the applicant, the Region IX EPA administrator, the CARB, affected local air pollution control districts, the chief executives of the city and county where the project will be located, the regional land use planning agency, and State, Federal Land Manager, or Indian Governing Body whose lands may be affected by the emissions from the proposed project. The Indian Governing Bodies are the Pala Band of Mission Indians and the Pechanga Band of Luiseno Mission Indians.

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
Each turbine is operating with a certified CO CEMS and adhering to retention of records requirements and reporting requirements. 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 and black start engine under normal operation.

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 turbines and black start engine under normal operation.

Rule 407 – Liquid and Gaseous Air Contaminants
This rule applies to the turbines but exempts the black start engine pursuant to subdivision (b)(1). The rule limits CO emissions to 2000 ppmv. The CO emissions from the turbine will be controlled by an oxidation catalyst to the BACT/LAER level of 4 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 turbines will comply with the sulfur limit in Rule 431.1. Therefore, compliance with this rule is expected.

Rule 409 – Combustion Contaminants
This rule applies to the turbines but expressly not to the internal combustion engine. 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 0.0067 gr/scf.

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

where:

A = Maximum PM_{10} emission rate during normal operation, 1.67 lb/hr (source tests)
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

$$D = F_d * \frac{20.9}{(20.9 - \%\ O_2)} * TFD = 8710 * \frac{20.9}{17.9} * 479 = 4.87\ E{+}06\ scf/hr$$

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, 479 MMBTU/hr

Grain Loading = [(1.67 * 12) / (4.29) (4.87 E+06)] * 7000 = 0.0067 gr/scf < 0.1 gr/scf

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 431.2—Sulfur Content of Liquid Fuels
A person shall not purchase any liquid fuel having a sulfur content in excess of 0.05 percent by weight, except existing supplies of any liquid fuel as of October 1, 1993, with sulfur content higher than 0.05 percent in storage may be used until such supply is exhausted. Facility conditions F14.1 and F14.2 require compliance with Rule 431.2.

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 turbine 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 0.0024 gr/scf.

Combustion Particulate (gr/scf) = (PM_{10}, lb/hr / Stack Exhaust Flow, scf) * 7000 gr/lb

PM_{10} = 1.67 lb/hr (source tests)

Stack exhaust flow = 4.87 E+06 scf/hr (see Rule 409 analysis, above)

Combustion Particulate = (1.67 / 4.87 E+06) * 7000 = 0.0024 gr/scf < 0.01 gr/scf limit

Rule 1110.2—Emissions from Gaseous- and Liquid-Fueled Engines

The black start engine is exempt per section (h)(2), which exempts emergency standby engines that operate 200 hours or less per year as determined by an elapsed operating time meter. Condition no. C1.1 will limit operation to no more than 50 hours in any one year, as proposed by A/N 555832. Condition no. D12.5 requires an operational non-resettable elapsed operating time meter.

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).

- ***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. Emissions will increase for the turbines, but not for the black start engine.

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.

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). Pursuant to Rule 1302(s), a facility is a major polluting facility (same as major 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.

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 and (2) black start emergency engine.

1. <u>A/N 555828, 555829, 555830, 555831—Turbine Nos. 1 - 4</u>

   The major source thresholds for NSR applicability and Prevention of Significant Deterioration (PSD) applicability are different. As discussed below under *<u>Regulation XVII—Prevention of Significant Deterioration</u>*, the CPP is <u>not</u> an existing major stationary source as defined by Rule 1702(m)(2) for PSD, because the pre-project potentials to emit for CO, NOx, SO_2, and PM_{10} emissions all are less than 250 tpy. Further, the modification does not constitute a major source in and of itself, because the net increases for CO, NOx, SO_2, and PM_{10} are less than 250 tpy. **Thus, CO, NOx, SO_2, and PM_{10} are not subject to PSD review, which would have included a PSD top-down analysis.**

   For the FDOC, the CPP was a "major polluting facility" for the purposes of NSR as shown in Table 1–Pre-Project Major Source Status, above, and subject to BACT/LAER. The BACT/LAER guidelines for simple cycle gas turbines were based on the SCAQMD permits issued to the City of Riverside Public Utilities Department on 4/28/05. The BACT limit for CO, however, was lowered to 4.0 ppmvd from the previous 6.0 ppmvd for the City of Riverside, because the District had sufficient test results for initial and periodic monitoring source testing for LM6000 turbines operating at existing power plants to demonstrate that 4.0 ppmvd is achieved in practice. Further, the applicant had confirmed with GE that the 4.0 will be consistently achievable. The initial source test results and subsequent periodic testing confirm each turbine meets the BACT standards.

   In addition, a top-down BACT analysis was performed for NOx. The control technologies evaluated were water/steam injection, dry low-NOx combustor design, catalytic combustor (e.g., XONON), selective catalytic reduction (SCR), and EMx (formerly SCONOx). Because the controlled NOx emission rate will be 1 - 2.5 ppm with water injection with SCR, steam injection with SCR, or dry low-NOx combustors with SCR, these technologies were all considered BACT. Consequently, the turbines were equipped with water injection with SCR.

   The BACT/LAER guidelines applicable to the FDOC are set forth in the table below.

Table 29 - Simple Cycle Gas Turbine MSBACT/LAER Requirements

	NOx	CO*	VOC	PM_{10}/SOx	NH_3
Simple Cycle Gas Turbine BACT Limits	2.5 ppmvd @ 15% O_2, 1-hr average	4.0 ppmvd @ 15% O_2, 1-hr average*	2.0 ppmvd @ 15% O_2, 1-hr average	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5.0 ppmvd @ 15% O_2, 1-hr average

Source: Table 31—Simple Cycle Gas Turbine MSBACT/LAER Requirements, on pg. 82 of FDOC.

These BACT/LAER guidelines have not changed since the FDOC was evaluated in 2009.

Currently, condition A99.1, A99.2, and A99.3 provide that the BACT limits of 2.5 ppm NOx, 4.0 ppm CO, and 2.0 ppm ROG shall not apply during commissioning, startup and shutdown periods. For the proposed project, the applicant has requested the addition of a maximum of 10 hours of maintenance operations per year. For the purposes of these conditions, maintenance shall be defined as optimizing and re-balancing of the NH_3 grid or catalyst modules, and the retuning and testing of the turbine control systems. During the maintenance period, the emissions may not be fully controlled. To account for the worse case, emission calculations will be based on uncontrolled emission rates for the full ten hours.

2. **A/N 555832—Black Start Emergency Internal Combustion Engine**

As there is no increase in emissions, BACT is not triggered.

For the FDOC, the Tier 2 engine was determined to meet the BACT requirements as set forth below.

Table 30 - Engine BACT Requirements and Manufacturer's Specifications

	NOx + NMHC	SOx	CO	PM
BACT Limits ≥ 750 HP	Tier 2 4.8 g/bhp-hr (6.4 g/kW-hr)	Diesel fuel with a sulfur content no greater than 0.0015% by wt. (Rule 431.2)	Tier 2 2.6 g/bhp-hr (3.5 g/kW-hr)	Compliance with Rule 1470: ≤ 0.15 g/bhp-hr Tier 2 0.15 g/bhp-hr (0.20 g/kW-hr)
AQMD Certified Emissions Levels (A/N 457437)	4.1 g/bhp-hr (0.02 g/bhp-hr ROG + 4.08 g/bhp-hr NOx)	Meets Rule 431.2.	0.75 g/bhp-hr	0.06 g/bhp-hr

Source: Table 35--Engine BACT Requirements and Manufacturer's Specifications, on pg. 93 of FDOC.

Further, LAER required a diesel particulate filter. The engine is equipped with a CleanAIR Systems PERMIT™ DPF. This DPF system was verified by CARB under Executive Order DE-05-002-01 to reduce emissions of diesel particulate matter consistent with a Level 3 device (greater than or equal to 85 percent reduction), with the use of low sulfur diesel with 15 ppm or lower sulfur content. New condition B61.2 will limit diesel fuel sulfur content to 15 ppm by weight, which will supplement the revised Rule 431.2 conditions, F14.1 and F14.2. Condition B61.2 will be tagged with Rule 1303(a)(1)--BACT and 40 CFR Subpart IIII.

- ***Rule 1303(b)(1)–Modeling***
- ***Rule 2005(b)(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--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.

1. **A/N 555828, 555829, 555830, 555831—Turbine Nos. 1 - 4**

   In a package dated 8/13/14, supplemented by subsequent additional modeling, the applicant provided modeling to demonstrate compliance with Rule 1303 (CO, PM_{10}, SO_2), Rule 2005 (NO_2), and Rule 1401 (Health Risk Assessment for toxics). The Request for Modeling Review, Rev. 1, dated 9/3/14, requested review of the modeling. On 10/2/14, Planning, Rule Development & Area Sources (PRDAS) staff Robert Wu noted that the modeling omitted the building downwash. In a revised package dated 10/7/14, the applicant provided modeling that incorporated the building downwash. The Request for Modeling Review, Rev. 2, dated 10/8/14, requested review of the revised modeling.

   The modeling review memo, dated 10/14/14, from Director of Strategic Initiatives Susan Nakamura to Sr. Engineering Manager Andrew Lee provided comments on the modeling. PRDAS staff has reproduced the applicant's modeling results and confirmed that the information provided in the requesting memo is consistent with the modeling files. The review memo concluded that the proposed project is in compliance with the modeling requirements of Rules 1303 and 1401.

   The applicant utilized AERMOD (version 14134) for the air dispersion modeling, which is the current EPA approved model and requires hourly meteorological data. The surface and upper air meteorological MET were obtained for 2006 to 2009, and 2012 from a nearby SCAQMD monitoring station located in Anaheim (AQS ID 060590007). For

NOx, CO, PM_{10}, and $PM_{2.5}$, the monitoring data from the Central Orange County Station (SCAQMD Anaheim (Pampas Lane)) meteorological station for 2010 through 2012, as available, were used to determine the background concentrations. As this station is located within five miles of CPP, the concentration measurements from this station are representative of the local air quality for the proposed project. For SO_2, the background concentration data are from the North Coastal Orange County Station (SCAQMD Costa Mesa meteorological station) for the same period, as available. While this station is located in a more coastal location and farther from the facility, it is the only station in the area that measures SO_2 concentrations.

- Normal Operation and Maintenance
  For the original permitting, the modeling was based on startups and normal operation. For the proposed project, the modeling is based on maintenance and normal operation. **The reason is that the uncontrolled maintenance rates are higher than the startup rates**. As discussed above, the uncontrolled NO_2 maintenance rate is 44 lb/hr, and the uncontrolled CO maintenance rate is 19.4 lb/hr.

  The table below presents reasonable worst-case emissions scenarios for a turbine for each combination of pollutant and averaging time corresponding to an air quality standard or significance limit.

Table 31 - Modeled Emission Rates - Normal Operation and Maintenance

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions Per Turbine, (lbs per entire averaging time period)	Modeling Emission Rate Per Turbine (g/sec)
1-hour	NO_2 and CO: One hour maintenance emissions (uncontrolled emissions from General Electric at 59 deg F ambient).	NO_2	44	5.54388
		CO	19.4	2.44435
	SO_2: Maximum hourly permitted emissions based on natural gas sulfur content of 0.25 gr/100 scf (periodic testing required by condition B61.1).	SO_2	0.34	0.04284
3-hour	SO_2: Maximum hourly permitted emissions based on natural gas sulfur content of 0.25 gr/100 scf.	SO_2	1.02	0.04284
8-hour	CO: 8 hours maintenance operations emissions.	CO	155.2	2.44435
24-hour	SO_2 and $PM_{10}/PM_{2.5}$: 10 hrs of maintenance operations and 14 hours of normal operations. (Maintenance emissions are the same as normal operation emissions for SO_2, $PM_{10}/PM_{2.5}$.)	SO_2	8.16	0.04284
		PM_{10}/ $PM_{2.5}$	40.08	0.21042

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions Per Turbine, (lbs per entire averaging time period)	Modeling Emission Rate Per Turbine (g/sec)
Annual	NO_2 and PM_{10}/$PM_{2.5}$: Maximum PTE reflecting total allowable starts, shutdowns, maintenance and normal operations (second annual operating scenario--2958 total hrs, 365 starts/shutdowns)	NO_2	15,017	0.21600
		PM_{10}/ $PM_{2.5}$	4822	0.06935

g/sec = (lbs/modeling period) * (453.59 g/lb) * (1/hr per modeling period) * (hr/60 min) * (min/60 sec). Annual g/sec reflects average emissions over an 8760 hour period.

The modeling results for normal operation and maintenance for a single turbine are summarized in the table below. For NO_2, SO2, CO, PM_{10} (federal 24-hr), and $PM_{2.5}$, the table shows that the highest predicted concentration for each turbine (bold font) plus the background concentration do not exceed the most stringent air quality standard. For PM_{10} (state 24-hr and annual), the highest predicted concentration for each turbine does not exceed the significant change in air quality concentration.

Table 32 - Modeling Results – Maintenance and Normal Operation

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m³)				Background Concentration (µg/m³)	Highest Predicted CTG Concentration Plus Background Concentration (µg/m³)	State Standard CAAQS (µg/m³)	Federal Standard, Primary NAAQS (µg/m³)	Significant Change in Air Quality Concentration (µg/m³)	Comply (Yes/No)
		CTG1	CTG2	CTG3	CTG4						
NO_2	1-hour	**7.8766**	7.60882	7.48579	7.53934	138.88	146.75	339	--		Yes
	Federal 1-hour	4.67182	**4.76275**	4.73611	4.72387	114.98	119.74	–	188		Yes
	Annual	**0.01955**	0.01938	0.01948	0.01947	32.93	32.95	57	100		Yes
SO_2	1-hour	**0.06074**	0.05869	0.05773	0.05815	24.89	24.95	655	--		Yes
	Federal 1-hour	0.0431	**0.04345**	0.04317	0.04276	12.58	12.62	--	196		Yes
	3-hour	0.04742	0.04619	0.04611	**0.04759**	156.94	156.99	--	1,300		Yes
	24-hour	0.01177	0.01177	**0.01181**	0.01177	5.50	5.51	105			Yes
CO	1-hour	**3.47287**	3.3548	3.30056	3.32417	3436.81	3440.28	23,000	40,000		Yes
	8-hour	**1.89034**	1.87458	1.86652	1.85499	2634.89	2636.78	10,000	10,000		Yes
PM_{10}	24-hour	**0.06218**	0.06190	0.06207	0.06207	53.00	53.06		150		Yes
	24-hour	**0.06218**	0.06190	0.06207	0.06207	53.00		50		2.5	Yes
	Annual	**0.00628**	0.00622	0.00625	0.00625	24.80		20		1	Yes
$PM_{2.5}$	24-hour	0.04236	**0.04264**	0.04246	0.04201	28.10	28.14		35		Yes
	Annual	**0.00628**	0.00622	0.00625	0.00625	11.0	11.01	12	12		Yes

2. **A/N 555832—Black Start Emergency Internal Combustion Engine**

The engine is exempt from modeling requirements per Rule 1304(a)(4), which exempts a source exclusively used as emergency standby equipment for nonutility electrical power generation, provided the source does not operate more than 200 hours per year as evidenced by an engine-hour meter. Condition C1.1 is being revised to limit operation to no more than 50 hours in any one year, and condition D12.5 requires an operational non-resettable elapsed operating time meter.

- ***Rule 1303(b)(2)—Offsets***
- ***Rule 2005(b)(2)-Offsets***

1. **A/N 555828, 555829, 555830, 555831—Turbine Nos. 1 - 4**

   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 offset ratio for emission reduction credits (ERCs) is 1.2-to-1.

   For the original project in 2009, the facility provided ERCs for the entire project because the Rule 1304 offset exemptions were not available due to the court decision. Rule 1304 exemption are available now. The applicable exemptions are Rule 1304(d)(2)(A) and (d)(2)(B). The rule language is reproduced below.

   (d) Facility Exemption

   (2) Modified Facility

   (A) Any modified facility that has a post-modification potential to emit less than the amounts in Table A shall be exempt from Rule 1303(b)(2).

   (B) Any modified facility that has a post-modification potential to emit equal to or more than the amounts in Table A shall be required to obtain offsets for the corresponding emissions increase, or the amount in excess of Table A figures if the pre-modification potential to emit was less than the amounts in Table A in accordance with Rule 1303 (b)(2).

TABLE A

Pollutant	Emissions in Tons per Year	
Volatile Organic Compounds (VOC)	4	
~~Nitrogen Oxides (NO_x)~~	~~4~~	*(RECLAIM facility)*
Sulfur Oxides (SO_x)	4	
Particulate Matter (PM_{10})	4	
~~Carbon Monoxide (CO)~~	~~29~~	*(currently in attainment)*

(3) Determination of emissions pursuant to Table A shall include emissions from permitted equipment excluding Rule 219 equipment not subject to NSR and shall also include emissions from all registered equipment except equipment registered pursuant to Rule 2100.

The number of ERCs and RTCs required are calculated below.

VOC: From Table 13, original project PTE = 17.25 lb/day (including black start engine)
From Table 24, new project PTE = 54.96 lb/day

Per Rule 1304(d)(2)(B), since prior PTE was less than 4 tpy (22 lb/day), ERCs are required for new project PTE in excess of 4 tpy.

ERCs required = (54.96 lb/day – 22 lb/day) x 1.2 offset factor =
39.55 lb/day → 40 lb/day

SOx: From Table 13, original project PTE = 4.52 lb/day
From Table 24, new project PTE = 14.44 lb/day

Per Rule 1304(d)(2)(A), ERCs are not required for new project if new project PTE is less than 4 tpy.

Since new project PTE is 14.44 lb/day and less than 4 tpy (22 lb/day), ERCs are not required.

PM_{10}: From Table 13, original project PTE= 39.93 lb/day (including black start engine)
From Table 24, new project PTE = 72.00 lb/day

Per Rule 1304(d)(2)(B), since prior PTE was greater than 4 tpy, ERCs are required for emissions increase.

ERCs required = (72.00 lb/day – 39.93 lb/day) x 1.2 offset factor =
38.50 lb/day → 39 lb/day

NOx: See *Rule 2005(c)(2)* analysis below for discussion on NOx RTC requirements. From Table 21, the number of RTCs required per year is 15,017 lbs for each turbine and 603 lbs for the engine.

Table 33 - Post-Modification ERCs and RTCs Required

A/N	Equipment	VOC ERCs, lbs/day	SOx ERCs, lbs/day	PM_{10} ERCs, lbs/day	NOx RTCs, lb/yr
555828	Turbine No. 1	10	0	10	15,017
555829	Turbine No. 2	10	0	10	15,017
555830	Turbine No. 3	10	0	10	15,017
55531	Turbine No. 4	10	0	9	15,017
555832	Emergency ICE, black start engine	Emergency equipment exempt from offsets per Rule 1304(a)(4).			603
	Total Project, lbs/day	40	0	39	60,671

A summary of the change of title applications submitted by CPP for the required VOC ERCs and the PM_{10} ERCs are shown in the table below. As Rule 1309—*Emission Reduction Credits and Short Term Credits* has not been SIP-approved, the STERCs have been converted to ERCs for use as offsets.

Table 34 - ERC Certificate Nos. and History

		Canyon Power Plant					**Seller of ERCs**		**Originator of ERCs**		
Emittent	**STERC Cert. No**	**ERC Cert. No.**	**Title Change Appl. No.**	**Date of Issue**	**ERC Type**	**Amount (lb/day)**	**Name**	**Cert. No.**	**Address**[2]	**Cert. No.**	**Zone**
ROG		AQ013821	560429	4/3/2014	ERC	36	International Paper Co., ID 156851	AQ013172	233 Wilshire Blvd Ste 310, Santa Monica, CA 90401	AQ001416	01-Coastal
ROG	A/N 568859 for change of title for the remaining 4 lb/days ROG ERCs approved on 11/18/14. ERC certificate issuance pending.										
					ROG Total	40					
PM_{10}		AQ013820	560428	4/3/2014	ERC	4	Element Markets LLC, ID 155272	AQ012083	2323 Valley St, Burbank, CA 91505	AQ000227	01-Coastal
PM_{10}		AQ013819	540426	4/3/2014	ERC	31	Koch Supply & Trading LP, ID 152470	AQ013743	420 S. Henry Ford Ave, Wilmington, CA 90744	AQ000802	01-Coastal
PM_{10}	AQ013747	AQ013832[1]	560293	3/27/2014	STERC	2	Superior Industries International Inc., ID	AQ012047	7800 Woodley Ave, Van Nuys, CA	AQ012047	01-Coastal
PM_{10}	AQ013748		560294		STERC	(STERC		AQ012048		AQ012048	
PM_{10}	AQ013749		560295		STERC			AQ012049		AQ012049	
PM_{10}	AQ013750		560296		STERC			AQ012050		AQ012050	

		Canyon Power Plant					Seller of ERCs		Originator of ERCs		
Emittent	**STERC Cert. No**	**ERC Cert. No.**	**Title Change Appl. No.**	**Date of Issue**	**ERC Type**	**Amount (lb/day)**	**Name**	**Cert. No.**	**Address[2]**	**Cert. No.**	**Zone**
PM_{10}	AQ013751		560297		STERC	Stream)	2083	AQ012051	91406	AQ012051	
PM_{10}	AQ013752		560298		STERC			AQ012052		AQ012052	
PM_{10}	AQ013759	AQ013834[1]	560299	3/27/2014	STERC	1 (STERC Stream)	Superior Industries International Inc., ID 2083	AQ012056	7800 Woodley Ave, Van Nuys, CA 91406	AQ012056	01-Coastal
PM_{10}	AQ013760		560300		STERC			AQ012057		AQ012057	
PM_{10}	AQ013761		560301		STERC			AQ012058		AQ012058	
PM_{10}	AQ013762		560302		STERC			AQ012059		AQ012059	
PM_{10}	AQ013763		560303		STERC			AQ012060		AQ012060	
PM_{10}	AQ013764		560304		STERC			AQ012061		AQ012061	
PM_{10}	AQ013753	AQ013833[1]	560305	3/27/2014	STERC	1 (STERC Stream)	Superior Industries International Inc., ID 2083	AQ012074	7800 Woodley Ave, Van Nuys, CA 91406	AQ012074	01-Coastal
PM_{10}	AQ013754		560306		STERC			AQ012075		AQ012075	
PM_{10}	AQ013755		560307		STERC			AQ012076		AQ012076	
PM_{10}	AQ013756		560308		STERC			AQ012077		AQ012077	
PM_{10}	AQ013757		560309		STERC			AQ012078		AQ012078	
PM_{10}	AQ013758		560310		STERC			AQ012079		AQ012079	
					PM_{10} Total	**39**					

1 George Haddad, IM, converted each stream of STERCs to an ERC on 5/21/14, pursuant to instructions from then NSR Senior Engineer George Illes.

2 The Certificates of Proof includes the address where the reduction was created, but not the company name.

2. **A/N 555832—Black Start Emergency Internal Combustion Engine**
   The engine is exempt from offset requirements per Rule 1304(a)(4), which exempts a source exclusively used as emergency standby equipment for nonutility electrical power generation, provided the source does not operate more than 200 hours per year as evidenced by an engine-hour meter. Condition C1.1 is being revised to limit operation to no more than 50 hours in any one year, and condition D12.5 requires an operational non-resettable elapsed operating time meter.

- ***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 applicable because ERCs are required for VOC and PM_{10}. Rule 2005(e) is applicable for the RTC purchases. Compliance is expected.

- ***Rule 1303(b)(4)-Facility Compliance***
  CPP is required to comply with all applicable rules and regulations of the District. As part of the associated significant Title V revision application, A/N 555827, the application included a Form 500-A2—Title V Application Certification. The form was signed by Manny Robledo, Electrical Operations Manager, on 8/28/13, and certified item 2.a., which states: "The equipment or devices to which this permit revision applies, will in a timely manner comply with all applicable requirements identified in Section II and Section III of Form 500-CA."

  On 2/21/14, Inspector George Wu performed the annual RECLAIM audit and Title V inspection. There were no Notices of Violation. The three Notices to Comply (NCs) with compliance dates are summarized below:

  - NC E09968, issued 2/28/14—Recertify the CEMS such at all CO air contaminant data points are within 10 to 95 percent of the full Span Range. To demonstrate compliance, submit CEMS application for modification of the existing CEMS.

    Application submitted 3/14/14. In a letter dated 7/22/14, Source Test Engineer Mike Cecconi provided notification of the final certification for the CEMS.

  - NC E09971, issued 4/11/14—Correct 500-ACC and 500-SAM forms with proper responsible official signature. Compliance achieved 4/15/14.

  - NC E09973, issued 5/1/14—Submit accurate APEP report. Apply proper missing data procedures when the data point didn't meet the requirements of

Rule 2012 Appendix A (B)(5). Apply proper missing data procedures when an out of control period occurs. Compliance achieved 5/13/14.

Based on the above, the CPP is complying with all applicable rules and regulations of the District.

- ***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. As shown in Table 1 above, CPP is an existing major polluting facility as defined by Rule 1302(s). The proposed modification is a major modification under Rule 1302(r), for which the applicability threshold includes an increase in PTE for NOx or VOC of 1 lb/day for a facility located in the South Coast Air Basin. Thus the following provisions are applicable.

- ***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.

Since the CPP is an existing facility applying for an increase in operating schedule, the analysis of alternative sites, sizes, production processes, and environmental controls are not applicable. The requested operational flexibility is required by CAISO for the CPP to qualify as a FRAC-MOO resource that will back up solar and wind generation as required.

- ***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.

Manny Robledo, Electric Operations Manager, Anaheim Public Utilities, provided a letter, dated 9/17/2014, certifying that the CPP and the Anaheim Combustion Turbine (ID 56940) are in compliance as required by Rules 1303(b)(5)(B) and 2005(g)(1).

- ***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).

  From Table 22, the project increase in PM_{10} emissions is 2.46 tpy and the increase in NOx emission is 15.36 tpy. Thus these provisions are not applicable.

Rule 1313-Permits to Operate

(g) Emission Limitation Permit Conditions

Every permit shall have the following conditions:

(1) Identified BACT conditions

(2) Monthly maximum emissions from the permitted source.

1. **A/N 555828, 555829, 555830, 555831—Turbine Nos. 1 - 4**

   (1) The BACT/LAER emissions limits are included in the "Emissions and Requirements" column. BACT conditions are tagged "Rule 1303(a)(1)-BACT."

   (2) The maximum monthly limits for VOC, PM_{10}, and SOx for each turbine are listed in condition A63.1.

2. **A/N 555832—Black Start Emergency Internal Combustion Engine**

   (1) The Tier 2 BACT emissions limits are included in the "Emissions and Requirements" column. In addition, BACT conditions, such as new condition B61.2 limiting diesel fuel sulfur content to 15 ppm by weight, are tagged "Rule 1303(a)(1)-BACT."

(2) Condition C1.1 limits monthly emissions by limiting maintenance and testing to 4.2 hrs in any one month.

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 35 – Rule 1325 Applicability

	NOx	SO_2	$PM_{2.5}$
Pre-Project Potential to Emit, TPY, Commissioning Year/Normal Operating Year, TPY (*Table 1*)	20.56/14.98	0.80/0.82	7.00/7.18
Is Pre-Project a Major Polluting Facility for Particular Pollutant?	Not major facility, PTE is less than 100 tpy.	Not major facility, PTE is less than 100 tpy.	Not major facility, PTE is less than 100 tpy.
Pre-Project Actual Emissions (2011 & 2012 Avg) TPY (*Table 12*)	7.54	0.27	2.15
Post-Project Potential to Emit, TPY (*Table 21*)	30.34	1.94	9.64
Net Emissions Increase (Post-Project PTE – Pre-Project actual)	22.80	1.67	7.49
If Pre-Project is a major polluting facility for particular pollutant, does post-project result in a net significant emissions increase?	Pre-Project not major facility.	Pre-Project not major facility.	Pre-Project not major facility.
If Pre-Project is not a major facility for particular pollutant, does Post-Project 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.	No, net increase is less than 100 tpy.
Rule 1325 Applicable?	**No**	**No**	**No**

Rule 1325 is not applicable to NOx, SO_2, and $PM_{2.5}$.

Rule 1401—New Source Review of Toxic Air Contaminants
Rule 2005(j) – 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.

1. **A/N 555828, 555829, 555830, 555831—Turbine Nos. 1 - 4**
   For the health risk assessment, the applicant performed a Tier 3 Screening Risk Assessment for each turbine using the latest version of the Rule 1401 Risk Calculator Program provided by the SCAQMD. The 1-hour ambient concentrations derived from the AERMOD dispersion modeling for Rules 1303

and 2005 were used for the input in combination with hourly and annual toxic pollutant emissions rates per turbine from Table 25 above. All health risk results conservatively reflect the potential post-modification potential to emit, rather than the incremental increase in emissions from the proposed project. The AERMOD analysis was normalized to complement the Rule 1401 screening tool by utilizing an emission rate of 1.0 gram per second for each turbine.

As discussed for the Rule 1303(b)(1) and Rule 2005(c)(1)(B) modeling analysis above, the modeling review memo, dated 10/14/14, from Director of Strategic Initiatives Susan Nakamura to Sr. Engineering Manager Andrew Lee concluded that the proposed project is in compliance with the modeling requirements of Rules 1303 and 1401. On 11/18/14, using the same procedure approved by the modeling review memo, the Tier 3 Screening Risk Assessments were revised for each turbine to reflect updated toxic emissions, using uncontrolled AP-42 emission factors only, to provide more conservative results.

The table below demonstrates that each of the three turbines will be in compliance with the MICR limit of 1 in a million, and the chronic and acute hazard index limits of 1.0.

Table 36 – Rule 1401 Compliance Summary

Health Risk Index	Residential/ Sensitive Receptor Risk	Worker Receptor Risk	Rule 1401 Standard (no T-BACT)	Complies?
Turbine No. 1				
MICR	4.26E-08	2.71E-08	1×10^{-6}	**Yes**
HIC	1.65E-04	3.18E-04	1	**Yes**
HIA	7.99E-04	1.54E-03	1	**Yes**
Turbine No. 2				
MICR	4.48E-08	2.62E-08	1×10^{-6}	**Yes**
HIC	1.74E-04	3.07E-04	1	**Yes**
HIA	8.41E-04	1.49E-03	1	**Yes**
Turbine No. 3				
MICR	4.70E-08	2.58E-08	1×10^{-6}	**Yes**
HIC	1.82E-04	3.02E-04	1	**Yes**
HIA	8.83E-04	1.46E-03	1	**Yes**
Turbine No. 4				
MICR	4.93E-08	2.60E-08	1×10^{-6}	**Yes**
HIC	1.91E-04	3.04E-04	1	**Yes**
HIA	9.26E-04	1.47E-03	1	**Yes**

2. **A/N 555832—Black Start Emergency Internal Combustion Engine**
   The engine is exempt from Rule 1401 per section (g)(1)(F), which exempts emergency internal combustion engines that are exempted under Rule 1304.

Rule 1470—Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, amended 5/4/2012

(b)(47) This defines a "new engine" as a stationary CI engine installed or to be installed at a facility on or after January 1, 2005. As the engine was installed in 2010, it is a "new engine" for the purpose of this rule.

(c)(2)(A) These requirements limiting non-emergency operation for facility located 500 feet or less from a school are not applicable because the closest school is about 2640 ft away.

(c)(2)(C) No person shall operate any new stationary emergency standby diesel-fueled CI engine (>50 bhp), excluding new direct-drive emergency standby fire pump engines and new direct-drive emergency standby flood control pump engines, unless it meets all of the following applicable operating requirements and emission standards.

(i) Such engines shall not operate more than 50 hours per year for maintenance and testing, as defined in (b)(43). Condition C1.1 implements this requirement.

(ii) New engines installed prior to January 1, 2011, shall emit diesel PM at a rate less than or equal to 0.15 g/bhp-hr, and meet the NMHC, NOx, NMHC + NOx, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13, CCR, Section 2423).

The engine meets the Tier 2 requirements referenced above, which is the same as the SCAQMD BACT limits. The PM emissions rate is 0.01 g/bhp-hr because the AQMD-certified PM emissions level is 0.06 g/bhp and the CleanAIR Systems DPF, required by LAER, is CARB verified for 85% reduction.

(c)(2)(F) Diesel Particulate Filter Cleaning Option for New Emergency Standby Engines

Owners or operators using a diesel particulate filter to comply with the diesel PM standards of this rule may remove the control equipment filter media for cleaning, provided all of the following conditions are met:

(i) the new emergency standby engine shall not be operated for maintenance and testing or any other non-emergency use while the diesel particulate filter media is removed;
(ii) the control equipment filter media shall be returned and re-installed within 10 working days from the date of removal;
(iii) the owner or operator shall maintain records indicating the date(s) the control equipment filter media was removed for cleaning and the date(s) the filter media was re-installed. Records shall be retained pursuant to the requirements specified in (d)(7)(C) (36 months).

These new requirements will be added in new condition E193.4.

(c)(7)(C)(i) To be part of a Demand Response Program (DRP) and enrolled in an Interruptible Service Contract (ISC) after on or after January 1, 2005, the engine is required to meet a diesel PM standard of 0.01 gram/bhp-hr or less, among other requirements. The engine with DPF meets this standard. The power plant, however, has not requested such enrollment.

<u>Rule 1472—Requirements for Facilities with Multiple Stationary Emergency Standby Diesel-Fueled Internal Combustion Engines</u>

(b) This rule is applicable to facilities operating three or more stationary emergency standby diesel-fueled ICEs. The facility has only this one engine under evaluation.

<u>REGULATION XVII – PREVENTION OF SIGNIFICANT DETERIORATION</u>

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.

- ***<u>RULES 1701, 1702, 1706–PSD APPLICABILITY</u>***
  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 new emissions for modified permit units shall be calculated as the potentials to emit.

  (1)(B) The emissions before modification 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, if any, are subject to PSD review.

Table 37 – Prevention of Significant Deterioration Applicability

	CO	**NOx**	**SO_2**	**PM_{10}**
Pre-Project Potential to Emit, Commissioning Year/Normal Operating Year, TPY (*Table 1*)	14.40/12.08	20.56/14.98	0.80/0.82	7.0/7.18
Is Pre-Project a Major Stationary Source?	Not major source, as PTE is less than 250 tpy for CO, NOx, SO_2, 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.)			
Pre-Project Actual Emissions (2011 & 2012 Avg), TPY (*Table 12*)	6.71	7.54	0.27	2.15
Post-Project Potential to Emit, TPY (*Table 21*)	32.40	30.34	1.94	9.64
Net Emissions Increase (Post-Project PTE – Pre-Project actual)	25.69	22.80	1.67	7.49
If Pre-Project is a major source, does Post –Project result in a significant net emissions increase?	Pre-project not major source.	Pre-project not major source.	Pre-project not major source.	Pre-project not major source.
If Pre-Project is not a major source, does Post-Project constitute a modification that would constitute a major source in and of itself?	No, net increase is less than 250 tpy.	No, net increase is less than 250 tpy.	No, net increase is less than 250 tpy.	No, net increase is less than 250 tpy.
PSD Applicable?	**No**	**No**	**No**	**No**

The 250 tpy major source threshold is applicable to the CPP, because it is not one of the 28 source categories subject to the 100 tpy threshold listed in Rule 1702(m)(1). One of the source categories subject to the 100 tpy threshold is fossil fuel-fired steam electric plants of more than 250 million BTU/hr, but this refers to a combined cycle plant, not a simple cycle plant like the CPP.

The CPP is <u>not</u> an existing major stationary source as defined by Rule 1702(m)(2) because the potentials to emit for CO, NOx, SO_2, and PM_{10} emissions all are less than 250 tpy. (If a source is a major source for any one regulated pollutant, it is considered to be a major source for all regulated pollutants.) Further, the modification does not constitute a major source in and of itself, because the net increases for CO, NOx, SO_2, and PM_{10} are less than 250 tpy. **Thus, CO, NOx, SO_2, and PM_{10} are not subject to PSD review.**

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 ("Guidance Document"), March 2011, provide applicability criteria for new sources and modified sources. Initial emission thresholds – known as Steps 1 and 2 of the Tailoring Rule – are provided for PSD and Title V permitting based on carbon dioxide equivalent (CO_2e) emissions. Not included in the Guidance Document is EPA's Step 3 of the GHG Tailoring Rule, issued on 6/29/12, which continues to focus GHG permitting on the largest emitters by retaining the permitting thresholds that were established in Steps 1 and 2. In addition, the Step 3 rule improves the usefulness of plantwide applicability limitations (PALs) by allowing GHG PALs to be established on CO_2e emissions, in addition to the already available mass emissions PALs, and to use the CO_2e-based applicability thresholds for GHGs provided in the "subject to regulation" definition in setting the PAL on a CO_2e basis.

From the Guidance document, **Tailoring Rule Step 1**--*PSD Applicability Test for GHGs in PSD Permits Issued from January 2, 2011, to June 30, 2011*--

PSD applies to the GHG emissions from a proposed modification to an existing major source if ***both*** of the following are true:

- Not considering its emissions of GHGs, the modification would be considered a major modification anyway and therefore would be required to obtain a PSD permit (called an "anyway modification"), ***and***

- The emissions increase ***and*** the net emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis ***and*** greater than zero TPY on a mass basis.

Tailoring Rule Step 2--*PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011*—

PSD applies to the GHG emissions from a proposed modification to an existing source if any of the following is true:

- PSD for GHGs would be required under Tailoring Rule Step 1.

OR BOTH:

- The existing source's PTE for GHGs is equal to or greater than 100,000 TPY on a CO_2e basis ***and*** is equal to or greater than 100/250 TPY (depending on the source category) on a mass basis, ***and***

- The emissions increase ***and*** the **net** emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO2e basis ***and*** greater than zero TPY on a mass basis.

OR BOTH:

- The existing source is minor for PSD (including GHGs) before the modification, ***and***

- The actual or potential emissions of GHGs from the modification *alone* would be equal to or greater than 100,000 TPY on a CO2e basis ***and*** equal to or greater than the applicable major source threshold of 100/250 TPY on a mass basis. Note that minor PSD sources cannot "net" out of PSD review.

Prior to the U.S. Supreme Court decision in *Utility Air Regulatory Group v. EPA (No. 12-1146)* issued on 6/23/14, the greenhouse gases would have been subject to PSD review under the second set of applicability criteria, as shown in the table below.

Table 38 – Prevention of Significant Deterioration Applicability for Greenhouse Gases Prior to Supreme Court Case

	CO_2e
Pre-Project (existing source) Potential to Emit, TPY *(Table 11)*	141,380.14 TPY > 100,000 TPY and > 250 TPY mass basis.
GHG Emissions Increase = Post-Project Potential to Emit *(Table 21)*	332,355.98 TPY > 75,000 TPY and > 0 TPY mass basis
Pre-Project Actual Emissions (2011 & 2012 Avg) *(Table 12)*	42,586.0 TPY
GHG Net Emissions Increase = Post-Project PTE – Pre-Project Actual	289,520.22 TPY > 75,000 TPY and > 0 TPY mass basis
PSD for Greenhouse Gases Applicable?	Yes

In *Utility Air Regulatory Group v. EPA* (No. 12-1146), the Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). The Court said that EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The Court also said that that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, to contain limitations on GHG emissions based on the application of BACT. The EPA, however, would need to justify the 75,000 TPY CO2e threshold on proper grounds. EPA is currently evaluating the implications of the Court's decision, including how the EPA will need to revise its permitting regulations and related impacts to state programs, and awaiting further action by the U.S. Courts.

On 7/24/14, EPA issued a memo regarding "Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in *Utility Air Regulatory Group v. Environmental Protection Agency*." On pg. 2, the memo addresses "Permit Applications for Sources and Modifications Previously Classified as "Major" Based Solely on Greenhouse Gas Emissions ("Step 2" Sources)." The memo indicates that in order to act consistent with its understanding of the Supreme Court's decision pending judicial action to effectuate the final decision, the EPA will no longer require PSD or Title V permits for Step 2 sources. More specifically, the EPA will no longer apply or enforce federal regulatory provisions or the EPA approved PSD State Implementation Plan (SIP) provisions that require a stationary source to obtain a PSD permit if greenhouse gases are the only pollutant (i) that the source emits or has the potential to emit above the major source thresholds, or (ii) for which there is a significant emissions increase and a significant net emissions increase from a modification (e.g., 40 CFR 52.21(b)(49)(v)). Nor does the EPA intend to continue applying regulations that would require that states include in their SIP a requirement that such sources obtain PSD permits. Thus, the EPA does not intend to continue processing PSD or Title V permit applications for Step 2 sources or require new applications for such permits in cases where the EPA is the permitting authority.

To act consistent with the Supreme Court's decision pending judicial action to effectuate the final decision and with EPA's decision to no longer require PSD or Title V permits for Step 2 sources and to no longer enforce SIP-approved rules such as Rule 1714, the SCAQMD will <u>not</u> be issuing a PSD permit for greenhouse gases for this project.

The only GHG PSD requirement is a top-down BACT analysis for GHGs. The available CO_2 control technologies are: (A) carbon capture and storage (CCS); (B) lower emitting alternative technology, and (C) thermal efficiency. Even if a top-down BACT analysis were performed for this project, the equipment and permit conditions would not change, as discussed below.

- Carbon capture and storage (CCS)--CCS technology is composed of three main components: (1) CO_2 capture and compression, (2) transport, and (3) storage/sequestration. As post-combustion carbon capture technologies are still in the developmental stage or installed on pilot scale projects, CCS technology is not feasible for the CPP.

- Lower emitting alternative technology-- Commercially available and low or non-GHG emitting power production technology include geothermal, hydroelectric, biomass fueled, solar power, nuclear powered, and wind facilities. It is not feasible to replace the existing simple cycle turbines with lower emitting alternative technology. In addition, as of January 1, 2015, the CAISO will require the CPP to provide a significant amount of flexible generation capacity to back up solar and wind generation in order to qualify as a FRAC-MOO facility.

- Thermal efficiency—As evaluated below, the thermal efficiency requirements from the proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (6/18/14)* will not be applicable to CPP. Each turbine will not meet the applicability threshold of selling the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system. In addition, the thermal efficiency of 1100 lbs CO_2/MW-hour$_{net}$ for the California Emissions Performance Standard (EPS) from *California Code of Regulations (CCR), Chapter 11—Greenhouse Gases Emission Performance Standard, Article 1—Provisions Applicable to Powerplants 10 MW and Larger (SB 1368)* is not applicable to CPP because it is a peaker facility that will not provide baseload generation at an annualized plant capacity factor of at least 60 percent.

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***
    The BACT analysis for NOx is combined with the ***Rule 1303(a)(1)—BACT/LAER*** 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. The NO_2 modeling analysis is combined with the **Rule 1303(b)(1)—Modeling** analysis, above.

  - ***(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."

The CPP is a new facility, because all Permits to Construct were issued on 3/13/10. Thus condition I298 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.

- RTCs for Turbines
  From Table 21, conditions I298.1 – I298.4 will require 15,017 lbs of NOx RTCs for each turbine.

- RTCs for Black Start Engine
  From Table 21, conditions I298.5 will require 603 lbs of NOx RTCs for the black start engine.

- RTCs Required to Be Purchased Prior to Issuance of Turbine Permits for Modification
  Total facility RTCs required = (4 turbines) (15,017 lbs/turbine) + (603 lb/engine) = 60,671 lbs RTCs.

  CPP has purchased 50,000 lbs RTCs for this project with the RTC trade registration completed on 2/6/14.

  The permit is anticipated to be issued in late December 2014. As the facility is a Cycle 1 RECLAIM facility, the compliance year will run from 1/1/15 through 12/31/15. Section B, printed 9/30/14, shows the RTCs available for 1/2015 – 12/2015, and 7/2015 – 6/2016 are 84,000 lbs, which is more than the 60,671 lbs required.

Year	NOx RTC Holding as of 1/1/2014
7/2014 - 6/2015	36,925 (To be conservative, these RTCs will not be counted towards the required RTCs because they may be used up for the 2014 compliance year.)
1/2015 - 12/2015	47,075
7/2015 - 6/2016	36,925
Total	84,000

- ***(e)--Trading Zone Restrictions***
  This is combined with the Rule 1303(b)(3) analysis, above.

- ***(g)—Additional Federal Requirements for Major Stationary Sources***
  Sections (g)(1) - (g)(4) are combined with the **Rule 1303(b)(5)** analysis above.

- ***(h)—Public Notice***
  The analysis is combined with the **Rule 212** analysis, above.

- ***(i)—Rule 1401 Compliance***
  This is combined with the **Rule 1401** analysis, above.

- ***Rule 2012-RECLAIM Monitoring Recording and Recordkeeping Requirements***
  A NOx CEMS is operating on each of the turbines, as required by condition D82.2.

Regulation XXX—Title V Permits

- **Rule 3003—Applications**
  This facility is in the RECLAIM program. The proposed project is considered as a "significant permit revision" for RECLAIM pollutants and non-RECLAIM pollutants but not hazardous air pollutants (HAPs) to the RECLAIM/Title V permit for this facility.

  Rule 3000(b)(31) defines a "significant permit revision" as any Title V permit revision where the cumulative emission increases of non-RECLAIM pollutants or hazardous air pollutants (HAPs) from these permit revisions during the term of the permit are greater than any of the following emission threshold levels:

Air Contaminant	Daily Maximum (lbs/day)
HAP	30
VOC	30
NOx	40
PM10	30
SOx	60
CO	220

  To determine if a project is considered as a "significant permit revision" for non-RECLAIM pollutants or HAPs, emission increases for non-RECLAIM pollutants or HAPs resulting from all permit revisions that are made after the issuance of the initial Title V permit (or renewal) shall be accumulated and compared to the above threshold levels. RECLAIM pollutants, however, are not subject to the emission accumulation requirements. For RECLAIM pollutants, the revision is significant for any modification at a RECLAIM facility that results in an emission increase of RECLAIM pollutants over the facility's starting Allocation plus the nontradeable allocations.

This proposed project will be the second permit revision (not including the annual re-issuances of Section B: RECLAIM Annual Emission Allocation) to the initial Title V permit issued to this facility on March 23, 2010.

The following table summarizes the cumulative emission increases in 30-day averages resulting from all permit revisions since the initial Title V permit was issued. For this project, the increases are from Table 23.

Table 39 - Significant Permit Revision Applicability

Facility Permit Rev No	Revision	HAP, lb/day	VOC, lb/day	NOx, lb/day	PM_{10}, lb/day	SOx, lb/day	CO, lb/day
0	Initial Title V Permit, A/N 476650, issued 3/23/10.						
1	First Permit Revision, A/N 531827—Revise condition A99.2 to increase hourly startup emissions from 6.3 lb/hr to 11.60 lb/hr.						
	A/N 531829—Turbine No. 1	0	0	0	0	0	0
	A/N 531831—Turbine No. 2	0	0	0	0	0	0
	A/N 531832—Turbine No. 3	0	0	0	0	0	0
	A/N 531833—Turbine No. 4	0	0	0	0	0	0
2	Proposed Second Permit Revision, A/N 555827—Increase operating schedule for turbines, decrease operating schedule for engine.						
	A/N 555828—Turbine No. 1	0	9.43	54.24	8.02	2.48	54.61
	A/N 555829—Turbine No. 2	0	9.43	54.24	8.02	2.48	54.61
	A/N 555830—Turbine No. 3	0	9.43	54.24	8.02	2.48	54.61
	A/N 555831—Turbine No. 4	0	9.43	54.24	8.02	2.48	54.61
	A/N 555832—Black Start Engine	0	0	0	0	0	0
	Cumulative Total	0	37.72	216.96	32.08	9.92	218.44
	HAP, VOC, PM10, SOx, CO: Maximum daily limits	30	30		30	60	220
	NOx: Starting allocation plus the nontradeable allocations.			0			
	Cumulative total exceed maximum daily limit or starting allocation plus nontradeable allocations?	No	Yes	Yes	Yes	No	No

Since the cumulative emission increases resulting from all permit revisions are greater than the VOC and PM_{10} emission threshold levels and the starting allocation plus nontradeable allocations for NOx, this proposed project is considered as a "significant permit revision."

Pursuant to Rule 3003(j), a proposed permit incorporating this permit revision will be submitted to EPA for a 45-day review. All affected States review procedures required by Rule 3003(m), and all public participation procedures required by Rule 3006(a) will be followed prior to the issuance of the permit. The affected States are CARB, the Pala Band of Mission Indians, and the Pechanga Band of Luiseno Mission Indians.

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(c)(2) public notice for a single public 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).

- **FEDERAL REGULATIONS**

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 18, 2014)

Under CAA section 111(d), the EPA is proposing emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA is proposing state-specific emission rate-based goals for carbon dioxide emissions from the power sector, as well as guidelines for states to follow in developing, submitting, and implementing state plans to achieve the state-specific goals. (79 FR 34830, 34832 - 833) Nationwide, by 2030, this rule would achieve CO_2 emission reductions from the power sector of approximately 30 percent from CO_2 emission levels in 2005. (79 FR 34832)

The EPA is proposing that, for the emission guidelines, an affected EGU is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an ''existing source'' for purposes of CAA section 111, and that in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs (79 FR 1430; January 8, 2014). The January 8, 2014 proposed GHG standards for new EGUs generally define an affected EGU as any boiler, integrated gasification combined cycle (IGCC), or combustion turbine (in either simple cycle or combined cycle configuration) that (1) is capable of combusting at least 250 million Btu per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input (stationary combustion turbines have an additional criteria that they combust over 90 percent natural gas); (3) sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system; and (4) was not in operation or under construction as of January 8, 2014 (the date the proposed GHG standards of performance for new EGUs were published in the Federal Register). The minimum fossil fuel consumption condition applies over any consecutive three-year period (or as long as the unit has been in operation, if less). The minimum electricity sales condition applies on an annual basis for boilers and IGCC facilities and over rolling three-year periods for combustion turbines (or as long as the unit has been in operation, if less). (79 FR 34854)

Applicability Analysis

The first step is to analyze the applicability of the proposed rule to the four identical simple cycle combustion turbines. The four applicability criteria and the applicability of each to the turbines are discussed below:

(1) Capable of combusting at least 250 million Btu per hour;

> The design heat input for each turbine is 479 MMBtu/hr, which is greater than the 250 MMBtu/hr applicability threshold.

(2) Combusts fossil fuel for more than 10 percent of its total annual heat input (stationary combustion turbines have an additional criteria that they combust over 90 percent natural gas);

The turbines are designed to operate on natural gas for 100% of the heat input at all times.

(3) Sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system on a three-year rolling average basis;

As each turbine will be permitted to operate no more than 2958 hours (including startups, shutdowns, and 10 hrs maintenance), it will supply less than 219,000 MWh net-electrical output to the grid.

$$50.95\ MW_{gross} * \frac{MW_{net}}{0.97\ MW_{gross}} * 2948\ hours = 154{,}846\ MWh_{net} < 219{,}000\ MWh_{net}$$

If each turbine is operating at maximum capacity for the full maximum operating schedule of 2958 hours, the maximum annual capacity would be slightly greater than one-third of its potential electrical output.

$$\text{Annual capacity factor} = \frac{50.95\ MW_{gross} * 2958\ hr}{50.95\ MW_{gross} * 8760\ hr} * 100\% = 33.76\% > 33.3\%$$

Since the 2958 hours includes 212.9 hrs startups, 60.8 hrs shutdowns, and 10 hrs maintenance during which a turbine is operating at less than the maximum potential electrical output, however, a turbine will be selling less than one-third of its potential electrical output to a utility distribution system on a three-year rolling average basis.

(4) Was in operation or under construction as of January 8, 2014 (the date the proposed GHG standards of performance for new EGUs were published in the Federal Register).

The turbines were started up in 2011.

The proposed regulation will not be applicable to CPP because turbine will not meet the applicability threshold of selling the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system.

40 CFR Part 60 Subpart GG–NSPS for Stationary Gas Turbines

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 commence 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 turbines are subject to the requirements of 40 CFR Subpart KKKK (see below) and thus are exempt from the requirements of this subpart pursuant to §60.4305(b).

<u>40 CFR Part 60 Subpart IIII--NSPS for Stationary Compression Ignition Internal Combustion Engines</u>

§60.4200(a)—The provision of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) engines as specified in paragraphs (a)(1) through (a)(4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

§60.4200(a)(2)(i) specifies this subpart is applicable to owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006 and are not fire pump engines. Therefore, this subpart is applicable to the engine under evaluation.

§60.4205(b)—Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE. Since the black start engine has a displacement of 27 liters, §60.4202 is applicable.

§60.4202(a)—Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

§60.4202(a)(2) provides that for engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

40 CFR 89.112—Exhaust emission from nonroad engines shall not exceed the applicable exhaust standards in Table 1 of this provision.

According to Table 1, for an engine rated at 250 kW for model year 2006 and later, Tier 2 is applicable (6.4 g/kW-hr NMHC + NOx, 3.5 g/kW-hr CO, 0.2 g/kW-hr PM). The engine complies with these limits, which are the same as the District BACT standards.

Permit condition: Accordingly, the Tier 2 limits for NMHC + NOx, CO, and PM tagged with 40 CFR 60 Subpart IIII will be added to the "Emissions and Requirements" column.

§60.4207(b)—Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

§80.510(b)—Except as other specifically provided in this subpart, all NR and LM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content.

(i) 15 ppm maximum for NR [nonroad] diesel fuel

(ii) 500 ppm maximum for LM [locomotive or marine] diesel fuel

Permit condition: New condition B61.2 will limit diesel fuel sulfur content to 15 ppm by weight, which is the same as required for the DPF. The condition will be tagged with Rule 1303(a)(1)--BACT and 40 CFR Subpart IIII.

§60.4209(a)— An owner or operator of an emergency stationary CI ICE that does not meet the standards applicable to non-emergency engines must install a non-resettable hour meter prior to start-up of the engine.

Permit condition: Condition D12.5 already requires a non-resettable hour meter. 40 CFR 60 Subpart IIII will be added to the existing rule tags.

§60.4209(b)—An owner or operator of a stationary CI ICE equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Permit condition: Condition no. E193.3 already requires a backpressure monitor that will provide a red light and audible alarm at the maximum allowable backpressure of 40 inches of water. 40 CFR 60 Subpart IIII will be added to the existing rule tags.

§60.4211(a)—An owner or operator who must comply with the emission standards specified in this subpart must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to manufacturer's emission-related written instructions;
(2) Change only those emission-related settings that are permitted by the manufacturer; and
(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply.

Permit condition: Pursuant to prior EPA guidance, condition E193.5 will be added to implement the above requirements regarding the engine, with 40 CFR 60 Subpart IIII as the rule tag.

§60.4211(c)—An owner or operator of a 2007 model year and later stationary CI ICE and must comply with the emission standards specified in §60.4204(b) [non-emergency engine] or §60.4205(b) [emergency engine], or an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to the fire pump engine power rating in table 3 to this subpart and must comply with the emission standard specified in §60.4205(c), must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

Permit condition: Pursuant to prior EPA guidance, the above requirements will be added to new condition E193.5, which will have 40 CFR 60 Subpart IIII as the rule tag. As discussed above, the engine is in compliance with the emissions standards specified in 40 CFR 60.4205(b).

§60.4211(f)—Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations....

Permit condition: Federal standards allow 100 hours per year for testing and maintenance and no time limit for emergency use. District requirements are more stringent and allow 50 hours for testing and maintenance, and 200 hours total including the 50 hours for testing and maintenance. Condition C1.1 already implements the more stringent District requirements (revised to 50 hr total per A/N 555832), and will add 40 CFR 60 Subpart IIII as a rule tag.

§60.4214(b)—If the stationary CI ICE is an emergency stationary ICE, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to on-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

Permit condition: Condition no. K67.2 already sets forth the recordkeeping requirements. 40 CFR Subpart IIII will be added as a rule tag.

§60.4214(c)—If the stationary CI ICE is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Permit condition: Condition K67.3 already requires records of diesel particulate filter inspections, replacements, and cleaning. 40 CFR Subpart IIII will be added as a rule tag.

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

Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input greater than 10 MMBtu/hr, which commenced construction, modification or reconstruction after February 18, 2005.

§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.

(b)—Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG.

Analysis: This subpart is applicable to the combustion turbines, which are rated at 479 MMBtu/hr each. The turbines were constructed in 2011, with the owner/operator entering into a contractual obligation on or about 2009 when the FDOC was issued. Compliance with Subpart KKKK is required by condition H23.1.

§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.

Analysis: In the "Emissions and Requirements" column, an emissions limit of 25 ppmv NOx continues to be included for the turbines pursuant to this subpart. Since source test reports demonstrate the four turbines are in compliance with the BACT limit of 2.5 ppmv @ 15% O_2, the turbines are in compliance with this section.

§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.

Analysis: 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 turbines continue to be expected to comply with the 0.06 lb/MMBtu limit. Accordingly, in the "Emissions and Requirements" column, an emissions limit of 0.06 lb/MMBtu SO_2 continues to be included for the turbines 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> The NOx emissions from each turbine are controlled with water injection but primarily with an SCR. The monitoring of the emissions from each turbine is 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

Further, condition B61.1 limits the H_2S to 0.25 grains/100 scf (0.34 lb/hr) in natural gas as that is the basis for the SOx emissions calculations. The condition also requires monthly laboratory analysis of the fuel.

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

§63.6080 Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

§63.6085 (b) A major source of HAP emissions is a contiguous site under common control that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year.

The actual and potential emissions are reviewed below.

Actual Emissions--The 2013 annual emissions reporting, reflected in the table below, indicates the highest single HAP rate is 0.37 tpy formaldehyde < 10 tpy. The combination of HAP rate is 0.38 tpy < 25 tpy.

Potential Emissions—

From the toxic contaminant emissions set forth in Table 25 above:

Total HAPs = (0.72 tpy/turbine)(4 turbine) + 0.0012 tpy/engine = 2.88 tpy < 25 tpy

Conclusion: This power plan is an area source for HAPs.

Table 40 - Reported Toxic Pollutants for 2013 (lb/yr):

Pollutant ID	Pollutant Description	Annual Emissions
106990	1,3-Butadiene	0.528
7664417	Ammonia ***Note: Ammonia is not a federal HAP.***	18,455.364
7440382	Arsenic	0.000
71432	Benzene	12.574
7440439	Cadmium	0.000
18540299	Chromium (VI)	0.000
50000	Formaldehyde	742.895 lb/yr = 0.37 tpy
7439921	Lead (inorganic)	0.002
91203	Naphthalene	1.370

7440020	Nickel	0.001
1151	PAHs, total, with components not reported	0.954
	Total HAPs	758.32 lb/yr = 0.38 tpy

Therefore, the CPP will continue to be an area source, and the requirements of this regulation do **not** apply.

<u>40 CFR Part 63 Subpart ZZZZ--NESHAPS for Stationary Reciprocating Internal Combustion Engines</u>

§63.6580 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions.

§63.6585(b) A "major source" is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year.

§63.6585(c) An "area source" is a source that is not a major source.

> <u>Analysis</u>: As analyzed for 40 CFR Part 63 Subpart YYYY above, the CPP will continue to be an area source.

§63.6590(a) This subpart applies to each affected source. An "affected source" is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

§63.6590(a)(2)(iii) A stationary RICE located at an area source of HAP emissions is new if construction of the stationary RICE is commenced on or after June 12, 2006. Therefore, the engine under evaluation is new.

§63.6590 (c) provides an affected source that meets any of the criteria in paragraphs (c)(1) through (c)(7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII for compression ignition engines or 40 CFR part 60 subpart JJJJ for spark ignition engines. No further requirements apply for such engines under this part.

(c)(1) A new or reconstructed stationary RICE located at an area source.

<u>Conclusion</u>: Since the emergency engine is a new compression-ignition RICE located at an area source, it is required to meet 40 CFR Part 60 Subpart IIII—

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. (See rule analysis for Subpart IIII, above.)

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.

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 CTG is controlled with SCR and CO catalyst to meet BACT limits. For each CTG, the post-control NOx, CO, and VOC emissions, however, are less than the major source thresholds.

From Table 21, the NOx emissions will be 7.51 tpy, which is less than the 10 tpy threshold. The CO emissions will be 8.06 tpy, which is less than the 50 tpy threshold. The VOC emissions will be 1.80 tpy, which is less than the 10 tpy threshold. Thus, the CAM regulations are not applicable.

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 CPP facility is complying 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, CPP 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.

This project to increase operating schedule is subject to CEQA. The California Energy Commission (CEC) is the lead agency. The approval of the Petition for Amendment by the CEC is tentatively scheduled for the Business Meeting on 12/10/14. The Order approving the Petition to Amend will complete the CEQA action for this project. The SCAQMD may issue the permits prior to the CEC's approval of the Petition to Amend.

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."

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 four identical turbines at CPP. § 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 analyzed for the proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 18, 2014)*above, if each turbine is operating at maximum capacity for the full maximum operating schedule of 2958 hours, the maximum annual capacity would be slightly greater than one-third of its potential electrical output.

$$\text{Annual capacity factor} = \frac{50.95\ MW_{gross} * 2958\ hr}{50.95\ MW_{gross} * 8760\ hr} * 100\% = 33.76\% < 60\%$$

Since the 2958 hours includes 212.9 hrs startups, 60.8 hrs shutdowns, and 10 hrs maintenance during which a turbine is not operating at its potential electrical output, however, the annual capacity will be less than the calculated 33.76% and significantly less than the required 60% capacity factor. Therefore, the EPS is not applicable to CPP.

RECOMMENDATION

Based on the above analysis, it is recommended that the Permits to Operate be issued following the conclusion of the required CEC, EPA, and public review and comment periods and subject to any comments received during these periods. The approval of the Petition for Amendment by the CEC is tentatively scheduled for the Business Meeting on 12/10/14. The Order approving the Petition to Amend will complete the CEQA action for this project. The SCAQMD may issue the permits prior to the CEC's approval of the Petition to Amend.