South Coast
Air Quality Management District
21865 E. Copley Drive, Diamond Bar, CA 91765-4182
(909) 396-2000 · www.aqmd.gov

February 28, 2003

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01-AFC-17
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Mr. Robert L. Therkelsen, Deputy Director
Systems Assessment & Facilities Siting
California Energy Commission
1516 9th Street
Sacramento, CA 95814-5512

Subject: Inland Empire Energy Center Project (01-AFC-17) to be located at Romoland in Riverside County, CA

Dear Mr. Therkelsen:

This letter is to inform you that the South Coast Air Quality Management District has completed our analysis of the proposed project to be located at Romoland, CA. Attached for your review is a Final Determination of Compliance (FDOC). Since the issuance of the Preliminary Determination of Compliance (PDOC) comments from the EPA and the applicant have resulted in numerous changes. For that reason the FDOC replaces in whole the PDOC, which was previously submitted to the California Energy Commission (CEC) on June 26, 2002.

The final permit to construct is contingent on the CEC approval of the project. In addition, the applicant will be required to obtain emission reduction credits for CO, PM10, VOC, and SOx before the final permit to construct can be issued. Prior to operation of the proposed project, the applicant will be required to obtain sufficient NOx RECLAIM Trading Credits to offset the total facility emissions for the first year of operation.

If you have any questions or wish to provide comments regarding this project, please call Mr. Li Chen (909) 396-2426 or Mr. John Yee (909) 396-2531.

Very truly yours,

Pang Mueller
Senior Manager
Refinery, Energy, & RECLAIM Administration
Engineering and Compliance

CM:TV:JTY:LC

Attachments

cc: Jim Bartridge, CEC
Gerardo Rios, US EPA
Mike Hatfield, Inland Empire Energy Center

CERTIFIED MAIL
Return Receipt Required

PROOF OF SERVICE (REVISED 12/9/02) FILED WITH
ORIGINAL MAILED FROM SACRAMENTO ON 3-3-03
K.A.M.

INLAND EMPIRE ENERGY CENTER PERMIT TO CONSTRUCT & FINAL DETERMINATION OF COMPLIANCE

COMPANY NAME AND ADDRESS

INLAND EMPIRE ENERGY CENTER, LLC (IEEC)
4160 Dublin Boulevard
Dublin, CA 94568-3139
SCAQMD ID #129816

Contact: Mike Hatfield, (925) 479-6716

EQUIPMENT LOCATION

The new facility will be located on an approximately 46-acre parcel (Assessor's Parcel No. 331-1808) in Section 14, Township 5S, Range 3W, near Romoland, Riverside County. The project site borders McLaughlin Road to the south, San Jacinto Road to the east, and Antelope Road to the west. The north side of the site is adjacent to an asphalt plant and the Burlington Northern Santa Fe (BNSF) railway. Site access from Ethanac Road will be provided by paved improvements to Antelope Road. The mailing address is 26226 Antelope Road, Romoland, CA 92585.

EQUIPMENT DESCRIPTION

Section H of the facility permit: Permit to Construct and temporary Permit to Operate

PROCESS 1: COMBUSTION AND POWER GENERATION SYSTEM 1: GAS TURBINE COMBUSTION					
Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
TURBINE, #1, NATURAL GAS, GENERAL ELECTRIC, MODEL 7251FB, COMBINED CYCLE, WITH DRY LOW NOx BURNERS, WITH STEAM INJECTION, 1,813 MMBtu/HR. WITH A/N 391432	D1	C17	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005 BACT]; NOx: 98.3 PPMV NATURAL GAS (8) [40CFR 60 SUBPART GG]; NOx (INTERIM): 14.03 LBS/MMSCF (1) [RULE 2012]; **CO**: 3 PPMV (4) [RULE 1303 BACT]; CO: 4 PPMV [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407];	29-1, 29-2, 40-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 193-1, 195-1, 195-2, 195-3, 296-1, 327-1
GENERATOR, 174 MW	B11				
GENERATOR, #1, HEAT RECOVERY STEAM	B13				

PROCESS 1: COMBUSTION AND POWER GENERATION **SYSTEM 1: GAS TURBINE COMBUSTION**					
Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
GENERATOR (HRSG) STEAM TURBINE GENERATOR, 322 MW COMMON WITH HRSG #2	B15			**ROG**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 150 PPMV (8) [40CFR 60 SUBPART GG]; SO2: (9) [40CFR 72 – ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GRAIN PER 100 SCF [RULE 1303-OFFSET]	
BURNER, DUCT, NATURAL GAS, 697 MMBtu/HR, LOCATED IN THE HRSG OF TURBINE #1 WITH A/N 391432	D14	C17	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005 BACT]; NOx: 0.2 LB/ MMBtu NATURAL GAS (8) [40CFR 60 SUBPART DA]; NOx(INTERIM): 14.03 LBS/MMSCF (1) [RULE 2012]; **CO**: 4 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **ROG**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 0.2 LB/MMBtu (8) [40CFR 60 SUBPART DA]; SO2: (9) [40CFR 72 – ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GRAIN PER 100 SCF [RULE 1303-OFFSET]	29-1, 29-2, 40-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 193-1, 195-1, 195-2, 195-3, 296-1, 327-1

PROCESS 1: COMBUSTION AND POWER GENERATION SYSTEM 1: GAS TURBINE COMBUSTION					
Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
CO OXIDATION CATALYST #1, SERVING TURBINE/HRSG #1 A/N 391423	C17	C4, D1, D14			
SELECTIVE CATALYTIC REDUCTION, #1, SERVING TURBINE/HRSG #1 WITH AMMONIA INJECTION, INJECTION GRID A/N:391423	C4 B18	C17		NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT]	12-1, 12-2, 12-3, 29-3, 179-1,179-2, 195-6, 232-1
STACK, #1 SERVING TURBINE AND HRSG #1, 195' HEIGHT X 18'6" DIAMETER A/N: 391432	S19	C4			
TURBINE, #2, NATURAL GAS, GENERAL ELECTRIC, MODEL 7251FB, COMBINED CYCLE, WITH DRY LOW NOx BURNERS, WITH STEAM INJECTION, 1,813 MMBtu/HR. WITH A/N: 391424 GENERATOR, #2, SERVICE TURBINE #2, 174 MW GENERATOR, #2, HEAT RECOVERY STEAM GENERATOR (HRSG) STEAM TURBINE GENERATOR, 322 MW, COMMON WITH HRSG #1	D2 B12 B20 B22 B15	C18	NOx MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005]; NOx 98.3 PPMV (8) [40CFR 60 SUBPART GG]; NOx(INTERIM): 14.03 LBS/ MMSCF (1) [RULE 2012]; **CO**: 3 PPMV (4) [RULE 1303 BACT]; CO: 4 PPMV [RULE 1303 BACT]; CO: 2000 PPMV (5) [RULE 407]; **ROG**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 150 PPMV (8) [40CFR 60 SUBPART GG] SO2: (9) [40CFR 72 – ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GR PER 100 SCF [RULE 1303-OFFSET]	29-1, 29-2, 40-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 193-1, 195-1, 195-2, 195-3, 296-1, 327-1

PROCESS 1: COMBUSTION AND POWER GENERATION
SYSTEM 1: GAS TURBINE COMBUSTION

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
BURNER, DUCT, NATURAL GAS, 697 MMBtu/HR, LOCATED IN THE HRSG OF TURBINE #2 A/N 391424	D21	C18	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005 BACT]; NOx: 0.2 LB/ MMBtu NATURAL GAS (8) [40CFR 60 SUBPART DA]; NOx (INTERIM): 14.03 LBS/ MMSCF (1) [RULE 2012]; **CO**: 4 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **ROG**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 0.2 LB/MMBtu (8) [40CFR 60 SUBPART DA]; SO_2: (9) [40CFR 72 – ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GR PER 100 SCF [RULE 1303-OFFSET]	29-1, 29-2, 40-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 193-1, 195-1, 195-2, 195-3, 296-1, 327-1
CO OXIDATION CATALYST #2, SERVING TURBINE/HRSG #2 A/N 391424	C18	D2, D21, C5			
SELECTIVE CATALYTIC REDUCTION, #2, SERVING TURBINE/HRSG #2, WITH A/N:391425 WITH AMMONIA INJECTION, INJECTION GRID	C5 B25	C18		**NH3**: 5 PPMV (4) [RULE 1303-BACT]	12-1, 12-2, 12-3, 29-3, 179-1, 179-2, 195-6, 232-1
STACK, #2, SERVING TURBINE AND HRSG #2, HEIGHT: 195'0", DIAMETER: 18'6" A/N: 391425	S26	C5			

PROCESS 1: COMBUSTION AND POWER GENERATION
SYSTEM 2: AUXILIARY EQUIPMENT

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
BOILER, AUXILIARY, NATURAL GAS FIRED, 129 MMBtu/HR A/N 391426 BURNER, NATURAL GAS, TBD	D3	C27	NOx MAJOR SOURCE	**NOx**: 7 PPMV (4) [RULE 2005 BACT]; NOx: 8.36 LBS/ MMSCF (1) [RULE 2012]; **CO**: 50 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **PM**: 0.1 GR/SCF (5) [RULE 409];	29-4, 40-2, 63-2, 82-3, 82-4, 99-4, 193-1, 195-4, 195-5, 296-1
CO OXIDATION CATALYST #3, SERVING AUXILIARY BOILER, A/N 391427	C27	D3, C6			
SELECTIVE CATALYTIC REDUCTION, #3, SERVING AUXILIARY BOILER WITH A/N:391427 WITH AMMONIA INJECTION, INJECTION GRID	C6 B25	C27		**NH3**: 5 PPMV (4) [RULE 1303-BACT]	12-1, 12-2, 12-3, 29-3, 179-1, 179-2, 195-7, 232-2
EMERGENCY GENERATOR, NATURAL GAS, IC ENGINE, CATERPILLAR, MODEL G3516LE, 1467 HP A/N 391430	D9		NOx: PROCESS UNIT	**NOx**: 1.5 GM/BHP-HR (4) [RULE 2005]; NOx: 380 LB/MMSCF (1) [RULE 2012]; **CO**: 2.0 GM/BHP-HR (4) [RULE 1303]; ROG: 1.5 GM/BHP-HR (4) [RULE 1303];	1-1, 12-4, 12-5, 67-2,193-1, 296-1
EMERGENCY FIRE PUMP, ENGINE, DIESEL, CATERPILLAR, MODEL 3406B, 337 BHP A/N 391431	D10		NOx: PROCESS UNIT	**NOx**: 5.89 GM/BHP-HR (4) [RULE 2005]; NOx: 240 LBS/1000 GAL (1) [RULE 2012]; **CO**: 3.55 GM/BHP-HR (4) [RULE 1303]; ROG: 1.0 GM/BHP-HR (4) [RULE 1303];	1-1, 12-4,12-5, 67-2,193-1, 296-1

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 2: INORGANIC CHEMICAL STORAGE					
SYSTEM 1: AMMONIA STORAGE TANKS					
STORAGE TANK, SERVING TURBINE #1, WITH A VAPOR RETURN LINE, 28% WT AQUEOUS AMMONIA SOLUTION, 16,000 GAL. A/N 391428	D7				144-1, 157-1, 193-1
STORAGE TANK, SERVING TURBINE #2, WITH A VAPOR RETURN LINE, 28% WT AQUEOUS AMMONIA SOLUTION, 16,000 GAL. A/N 391429	D8				144-1, 157-1, 193-1
PROCESS 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE-SPECIFIC RULE					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, ARCHITECTURE COATINGS	E			ROG: (9) [RULE 1113, 5-4-1999; RULE 1171, 6-13-1997]	67-3
RULE 219 EXEMPT CLEANING EQUIPMENT USING SOLVENTS	E			ROG: (9) [RULE 1171, 6-13-1997]	23-1

BACKGROUND

Inland Empire Energy Center, LLC (IEEC), a wholly owned subsidiary of Calpine Corporation, submitted an application on August 17, 2001 to the California Energy Commission (CEC) seeking certification of a brand new power plant to be located at Romoland in Riverside County. The power plant will consist of two combustion turbine generators (CTG) with heat recovery steam generators (HRSG) and one steam turbine generator (STG), with a total peak generating capacity of 670 MW. The gas turbines are expected to be General Electric PG7251 (FB) units. Each turbine will drive a 174 MW generator. The HRSGs supply steam to a condensing steam turbine, which in turn drives a 204 MW generator. Net power generation capacity after taking away auxiliary power consumption is 538 MW. The HRSGs are equipped with duct burners (DB), and the duct burners are fired during peak periods for additional power output. Net power generation capacity with duct burners firing increases from 538 MW to 670 MW. Selective catalytic reduction (SCR) systems and CO oxidation catalysts will be utilized for control of NOx and CO emissions, respectively. Two 16,000-gallon ammonia storage tanks and an ammonia distribution grid will be built for the SCR systems. A natural gas fired boiler (steam capacity of 100,000 pound/hour) will be installed to provide steam for serving the steam turbine, the HRSG, and for auxiliary purposes as needed. Emissions from the boiler will be conditioned with a separate SCR system and a CO oxidation catalyst. A 14-cell mechanical draft evaporative cooling tower is to be built to provide cooling for the steam turbine condenser. Additional auxiliary equipment also include a natural gas fired 1,000 kW emergency generator and a 370 horsepower diesel emergency fire pump engine.

The facility will be located in the area that is zoned for industrial use. However, the proposed site is very close to the Romoland Elementary School that serves some 800 children. The distance between the school and the facility is 0.73 mile based on the data provided in the application, but is less than ¼ mile according to the school district. Because of the site proximity, the Romoland School District has filed a request to intervene with the CEC and to seek mitigation plans. The CEC will address the intervene request.

As a part of the CEC certification process IEEC submitted applications to the South Coast Air Quality Management District (AQMD) seeking air quality permits for the equipment. The following table shows corresponding application numbers.

Table 1 Applications Submitted by IEEC

Application number	Equipment Description
391432	Turbine #1 with HRSG
391424	Turbine #2 with HRSG
391426	Auxiliary boiler
391423	SCR for turbine #1
391425	SCR for turbine #2
391427	SCR for auxiliary boiler
391428	Aqueous ammonia tank #1
391429	Aqueous ammonia tank #2
391430	Emergency generator
391431	Emergency fire pump engine
391464	Facility Title V permit application

The applications were submitted to AQMD on September 16, 2001. AQMD deemed the original applications incomplete on November 8, 2001. AQMD indicated the deficiencies and requested additional information. IEEC provided the requested documents to AQMD on November 16, 2001. After reviewing the applications with the supplemental materials AQMD deemed the applications complete on November 21, 2001.

The facility has applied to be a Title V facility and to be included in the NOx RECLAIM program.

AQMD issued the Preliminary Determination of Compliance (PDOC) on June 26, 2002 along with the public notice. Comments on the PDOC were received from the US EPA, the Southern California Association of Governments (SCAG), the National Park Service, one citizen, and the applicant. The comments are discussed in the FDOC. AQMD will also reply to the respondents in letter after the FDOC is published.

PROCESS DESCRIPTION

The power plant will utilize combined-cycle for power generation. The gas turbine (Brayton) cycle is combined with a steam turbine (Rankine) cycle for improved thermal efficiency. The gas turbine cycle will utilize two General Electric 7FB combustion gas turbines. The 7F series gas turbine is currently the most advanced and commercially available gas turbine produced by GE. The 7FB model offers better performance over the earlier 7FA model. It has a higher firing temperature and a higher compression ratio than the 7FA model. Consequently the thermal efficiency is higher. The turbines will be fired with pipeline natural gas exclusively, to be brought to the facility through construction of a new natural gas pipeline. At base load each turbine produces 174 MW of power under average ambient conditions.

The steam turbine cycle consists of two heat recovery stream generators (HRSG) equipped with duct burners and a condensing steam turbine generator. The HRSG will be a vertical flow, triple pressure, reheat type steam generator. Each HRSG is connected to one combustion gas turbine. Exhaust gases from the two gas turbines are used to generate steam in the HRSGs. Steam from both HRSGs is fed into the steam turbine generator for power generation. The steam turbine has three-stage turbines for improved efficiency. Approximately 204 MW will be produced by the steam turbine when the combustion turbines are operating at base load at average ambient conditions, without duct burner firing.

The power plant has two ways of increasing power production beyond base load besides through evaporative cooling of the inlet air. The first method is by steam injection that applies a portion of the stream produced from the HRSGs to the combustion gas turbine. The second method is by addition of heat input through the HRSG duct burners. The duct burners of each HRSG have a heat input rate of 697 MMBtu/hr. With steam injection and duct burners firing, the peak output on a 97 °F day could reach approximately 670 MW.

At base load the gross power generation capacity is 552 MW. Net power output, after taking away auxiliary loads of 14 MW, is 538 MW. Fuel consumption is approximately 1,813 MMBtu/hr for each turbine (at 36 °F and 60% relative humidity). The fuel consumption rate equates to a heat rate of about 6,740 Btu/kW-hr based on the higher heating value (HHV), or about 6,078 Btu/kW-hr based on the lower heating value (LHV). The LHV based thermal efficiency is 56.1%.

Additional 132 MW can be generated through the steam turbine generator with the duct burners firing. Since the mechanism of generating power through duct burner firing is essentially a Rankine cycle (steam cycle), the efficiency is much less than the combined cycle efficiency of 56.1%. The gas turbine with the duct burners firing is equivalent to producing power of 670 MW at a fuel consumption rate of 5,020 MMBtu/hr. This fuel consumption rate equates to a heat input rate of about 7,490 Btu/kW-hr based on the higher heating value (HHV), or about 6,750 Btu/kW-hr based on the lower heating value (LHV). The LHV based thermal efficiency is now 50.6%. The efficiency consideration will be reviewed by the CEC.

The following table is a brief description of the combustion gas turbine generator (CTG)

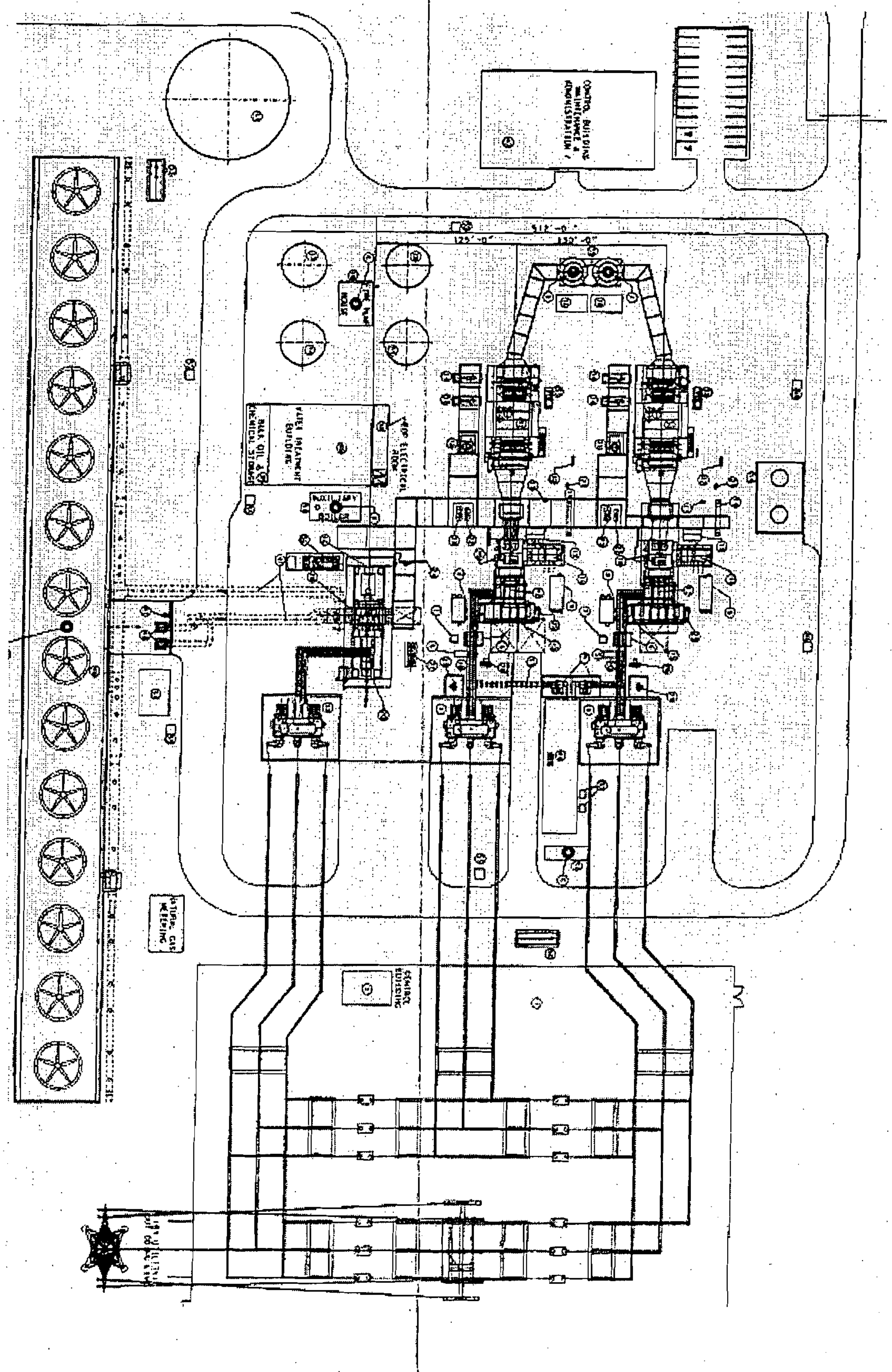
Table 2 Combustion Gas Turbine and HRSG Specifications

Parameter	Specifications
Manufacturer	GE
Model	7251 FB
Fuel Type	Pipeline Natural Gas
Natural Gas Heating Value (HHV)	1,010 Btu/scf
Gas Turbine Heat Input (HHV)	1,813 MMBtu/hr
Gas Turbine Heat Input (HHV), including Duct Burners	2,510 MMBtu/hr
Duct Burner Heat Input (HHV)	697 MMBtu/hr
Fuel Consumption	1.795 MMscf/hr
Fuel Consumption, with Duct Burners Firing	2.485 MMscf/hr
Gas Turbine Exhaust Flow	684, 437 DSCFM(1)
Gas Turbine Exhaust Flow, with Duct Burners Firing	700, 387 DSCFM(2)
Gas Turbine Power Generation	174 MW
Steam Turbine Power Generation	204 MW
Steam Turbine Power, with Duct Burners Firing	322 MW
Gross Power Generation	552 MW
Net Power Generation	538 MW
Net Power Generation, with Duct Burners Firing	670 MW
Net Plant Heat Rate, LHV	6,078 Btu/kW-hr
Net Plant Efficiency	56.1% (LHV based)

(1) Provided in the application, at 61 deg. F
(2) Provided in the application, at 36 deg. F

The next graph provides a general layout of the facility.

The three groups of vertical lines represent the connections from the two combustion gas turbines and one steam turbine to the electric power grid. The two HRSGs are near the top-right portion of the diagram, while the steam turbine is on the left side close to the cooling tower. The 14-cell cooling tower can clearly be seen on the left side of the graph.



AIR POLLUTION CONTROL (APC)

Multiple emission control methods are utilized for the combustion gas turbines and the HRSGs duct burners. On the front end, the combustion gas turbines are equipped with GE's Dry Low NOx (DLN) burners. These burners are capable of achieving high combustion efficiency while mitigating NOx emissions by using staged, premixed combustion. As a result of high combustion efficiency, emissions of CO, ROG, and PM10 are small. The 1-hour average NOx concentration is limited to 25 ppmv, dry basis at 15% O_2. On the back end, selective catalytic reduction (SCR) with ammonia injection is used for further reduction of NOx emissions, and CO oxidation catalyst is used for CO emissions reduction. As a result NOx emissions are limited to 2.0 ppmv, 1-hour average, dry basis at 15% O_2. CO emissions are limited to 3.0 ppmv without the duct burners firing and 4 ppmv with the duct burners firing, 1-hour average, dry basis at 15% O_2. ROG emissions are limited to 2.0 ppmv when the duct burners are firing, dry basis at 15% O_2, 1-hour average. ROG emissions are limited to 1.4 ppmv when the duct burners are not firing, actual stack concentration, 1-hour average. The combustion gas turbines and duct burners minimize SOx and PM10 emissions by use of commercial grade natural gas.

The auxiliary boiler utilizes another set of SCR and CO oxidation catalyst for NOx and CO emissions control. The auxiliary boiler will burn natural gas exclusively, and it will be subject to new source review (NSR) that includes BACT, modeling analysis, and offset requirements.

Detailed descriptions of the air pollution control components are given in the next sections.

Selective Catalyst Reduction (SCR) (A/N 391423, 391425, 391427)

The IEEC has proposed to use an SCR system developed by Nooter Eriksen using a Cormetech catalyst. The following are the specifications of the SCR system used for a combined cycle gas turbine system. The SCR will be located at downstream of the HP evaporator section of the HRSG. Temperature window is between 450 °F and 700 °F.

Table 3 Selective Catalyst Reduction (SCR)

Catalyst Properties	Specifications
Manufacturer	Cormetech
Catalyst Description	Titanium-Vanadium Oxides
Catalyst Type	Honeycomb
Catalyst Volume	~4,379 ft^3
Space Velocity	~11,000 hr^{-1}
Area Velocity	~115 ft/hr
Ammonia Injection Rate	400 lb/hr of 28% wt. Aqueous ammonia solution
NOx removal efficiency	>90%
NOx level at the outlet	2.0 ppmv, dry basis at 15% O_2, 1 hour average

Catalyst Properties	Specifications
Temperature at the outlet	630 °F
SCR Reactor Temperature	450 to 700 °F
Unit Cost	$1.5 million

<u>CO Oxidation Catalyst</u>

The CO oxidation catalyst is permitted together with the SCR catalyst. IEEC has indicated that Nooter Eriksen is responsible for the catalyst system and the manufacturer is expected to be Engelhard. The following are the CO catalyst specifications. The CO catalyst will be located at the upstream of the HP evaporator section of the HRSG. Operating temperature window is between 600 °F and 1,100 °F.

Table 4 CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	Engelhard
Catalyst Type	Corrugated stainless steel foil substrate, coated with platinum group metals impregnated alumina washcoat
Catalyst Volume	240 ft^3
Space Velocity	200,000 hr^{-1}
Area Velocity	115 ft/hr
CO removal efficiency	90%
CO, without duct burners firing	3 ppmv, 1-hour average, dry at 15% O_2
CO, with duct burners firing	4 ppmv, 1-hour average, dry at 15% O_2
ROG, without duct burners firing	1.4 ppmv, 1-hour average, actual stack concentration
ROG, with duct burners firing	2.0 ppmv, 1-hour average, dry at 15 % O_2
CO Catalyst Total Cost	$800,000
Catalyst Replacement Cost	$700,000

<u>Ammonia Storage (A/N 391428 and A/N 391429)</u>

Aqueous ammonia (ammonium hydroxide at 28 percent nominal concentration by weight) will be used in the SCR for NOx emissions control. The SCR has a specific temperature window when NOx in the exhaust will react with ammonia and form nitrogen and water. Aqueous ammonia will be stored in two 16,000 gallon capacity storage tanks. The storage tanks are fixed roof vertical cylindrical tanks equipped with a vapor recovery system. A truck-mounted vapor recovery system will be connected to the tank vapor recovery system during the filling process. The storage tank will be maintained at ambient temperature, and it has a pressure relief value set to at least 25 psig. Given it is unlikely the tank pressure will exceed 25 psig, the ammonia emissions are very minimal. A detailed calculation is included in the Appendix H.

Ammonia Vaporization and Injection system

Each gas turbine and HRSG will be equipped with an ammonia vaporization and injection system. For each system the aqueous ammonia is transported from the ammonia storage tank to a steel ammonia vaporization chamber through an injection pump. The ammonia vaporization chamber will be approximately 15 ft long and 20 inches in diameter. The vaporization chamber will be heated by hot exhaust gas from the HRSG, typically around 800 °F. Once vaporized, the aqueous ammonia is sent to the HRSG injection nozzles and to the SCR by using a forced draft electric fan rated at approximately 20 HP. The system is equipped with a second ammonia injection fan which serves as a backup to the primary unit.

AUXILIARY EQUIPMENT

Auxiliary Boiler (AN391427)

The auxiliary boiler is primarily used to generate steam when the plant is offline. Steam produced by the auxiliary boiler will be used for the following purposes; 1) steam turbine gland steam (necessary to keep air out of the steam turbine and also keep it warm), 2) steam jet air ejectors (necessary to maintain condenser vacuum), 3) HRSG high pressure drum sparging (necessary to keep drums hot and under pressure in order to minimize stresses resulting from thermal and pressure cycling), 4) condenser hotwell sparging (necessary to maintain condenser temperature), and 5) deaeration steam for auxiliary boiler deaerator (to assist in removal of oxygen from the boiler feed water). When the weather turns cold, the auxiliary boiler steam is also used for heat tracing of piping and equipment requiring freeze protection.

The IEEC has not finished the selection process of the auxiliary boiler. However, the heat input rate has been chosen to be 129 MMBtu/hr. The boiler will be fired with commercial grade natural gas, and will have a SCR for NOx emissions control and an oxidation catalyst for CO emissions control. The emissions limits, as required by BACT and determined in the later sections, are 7 ppm for NOx, 50 ppmv for CO, 1-hour average, dry basis at 3% O_2.

IEEC has argued that the boiler emissions should not be counted in new source review (NSR) based on the fact that it is unlikely the boiler will be in use simultaneously with the gas turbines, and that the turbine PTE is greater than the auxiliary boiler. While it may be true that the boiler and the turbine will not be operating at the same time, the fact that the boiler will be a separately permitted equipment warrants individual PTE and NSR determinations. Furthermore, there is no enforceable mechanism that guarantees the boiler and the turbines not to operate simultaneously. Therefore, the boiler emissions must be included in the entire facility NSR considerations.

Emergency Generator (AN391430)

The emergency generator is to provide power in the event of an emergency. The generator will be driven by a natural gas powered internal combustion engine. The IC engine was chosen to be a Caterpillar, model G3516LE. The engine has a power rating of 1,467 BHP, and a fuel consumption rate of 564 lb/hr. This engine is subject to NSR, and will need to satisfy the requirements of BACT. However, emergency equipment is exempt by Rule 1304(a)(4) from offset and modeling requirements. The non-RECLAIM pollutants emissions are not to be included in the facility's ERC determinations.

Per RECLAIM rules emergency equipment NOx emissions are exempted from modeling requirement. However, they are not exempted from offset requirement. Therefore, the emissions will be included in the facility's RTC determinations.

Emergency Fire Pump Engine (AN391431)

The fire pump engine will be a Caterpillar unit, model 3406B. It has a power rating of 337 BHP at 1,750 rpm. This is a diesel powered internal combustion engine, and the fuel consumption is 18.3 gallon per hour. This engine will need to satisfy the requirements of BACT. However, emergency equipment is exempt by Rule 1304(a)(4) from offset and modeling requirements. The non-RECLAIM emissions are not to be included in the facility's ERC determinations.

Similar to the emergency generator, NOx Emissions will be included in the RTC determinations according to the RECLAIM rules.

Exhaust Stacks

Each CTG/HRSG will be equipped with a 195-ft tall, 18.5-ft diameter stack. A set of the stack data is shown in the next table. The stack data are used in the air quality modeling analysis.

Table 5 Stack Parameters

Stack Parameters	Specifications
Stack Diameter	18.5 FT
Stack Height	195 FT
Stack Exhaust Temperature	260 F, base load, 97 F ambient temperature 136 F, peak load, 36 F ambient temperature
Stack Gas Flow Rate	901,811 SCFM

The stack height must comply with the applicable regulations and rules. The CEC has the responsibility of determining the compliance.

Cooling Tower

The 14-cell cooling tower provides heat extraction (rejection) for the gas turbines and the steam turbine generator. At peak load when the turbines are operating with the duct burners firing, approximately 145,000 gallons per minute (GPM) of recirculating water are required to condense the exhaust steam. Maximum drift, i.e., the fine mist of water droplets entrained in the warm air leaving the cooling tower, will be limited to 0.0005 percent of the circulating water flow.

The applicant submitted a screening level risk assessment of the potential toxic air contaminants (TAC) emissions from the entire plant including cooling tower. In the modeling analysis the water flow rate per cell was assumed to be 169,847 GPM. The MICR level is found to be approximately 0.3×10^{-6}, less than the 1 in a million threshold. As so, the cooling tower does not require a separate permit since the MICR is below the 1 in a million threshold.

Table 6 Cooling Tower Data Summary

Cooling Tower Parameters	Specifications
Number of Cells	14
Fan Stack Diameter (ft)	37.2
Exhaust Temperature (F)	72
Exhaust Flow per Cell (ACFM)	1,721,000
Water Flow Rate per Tower (GPM)	169,847
Drift per Tower (lb/hr)	425

EPA provided comments on the issue of cooling tower exemption from permits and NSR after the draft permit (PDOC) was released. EPA argued that the cooling tower should be subject to NSR, and the emissions from the cooling tower should be offset by PM10 ERCs. AQMD researched the issue and determined that the cooling tower is exempt in accordance with the SIP approved AQMD Rule 219. Details of the AQMD research are contained in the attached letter from Pang Mueller of AQMD to Gerardo Rios of EPA in February 2003.

EMISSIONS

This section discusses the potential emissions from the power plant including the combustion gas turbines and the auxiliary equipment.

GAS TURBINE OPERATION MODES

The combustion gas turbine generators have four possible operating scenarios (modes). Emissions from the four operating modes are distinctly different and must be calculated independently. The following table contains a description of the operating modes.

Table 7 Operating Modes of the Combustion Gas Turbines

Mode	Description
Commissioning	This is the process of "tuning in" the combustion gas turbines. The facility will follow a systematic approach to optimize performance of the combustion gas turbines and the emission control equipment. A description of this step by step process is included in Appendix A. Emissions are expected to be high. However, this mode affects only the first year pollutant emissions. According to the application, it takes about 23 days to commission one gas turbine.
Startup	The application has specified two types of startups, hot and cold. Cold startup takes about 3 hours while hot startup takes 1 hour. The application assumes a single emission factor that applies to both the hot and cold startups. Startup may happen daily. Emissions are high during the startup period.
Normal Operation	Normal operation is when the combustion gas turbines and all the air pollution control devices are working at designed levels, i.e., NOx of 2.0 ppm, CO of 3 ppm and ROG of 2 ppm. Emissions may vary due to ambient conditions and duct burners firing.
Shutdown	The application did not describe specifically the emission levels during the shutdown process. Although the shutdown process typically emits less than the startup process, the application elected to treat the shutdown as equivalent to the startup. Therefore, emission factors are assumed the same as the startup emission factors.

EMISSIONS DURING GAS TURBINE COMMISSION PERIOD

Gas turbine commissioning consists of zero load, partial load and full load tests performed for the purposes of optimizing turbine machinery, gas turbine combustors and the emission control systems. According to the schedule provided in the application, the first turbine is expected to be commissioned in approximately 23 days. The second turbine takes less time as it is identical to the first one, and it is expected to take 13 days. Emissions during the commissioning period will be higher than during normal operations because the combustors have not been properly tuned, and the SCR systems may not be operational. Refer to Appendix A for the detailed calculations of the emissions during the commissioning period. As determined in Table A-11 of Appendix A, the next table contains the equivalent NOx and non-RECLAIM pollutants emissions factors during the commissioning period.

Table 8 NOx Emission Factor of the Commissioning Period

Emissions	NOx	CO	ROG	PM10	SOx
Total Emissions (lbs), Both Turbines	133,997	155,366	8,427	7,884	866
Total Hours (hr), Both Turbines	876	876	876	876	876
Total Fuel (MMscf), Both Turbines	1,215	1,215	1,215	1,215	1,215
Emission Factor (lb/MMscf)	110.29	127.87	6.94	6.49	0.71

EMISSION LIMITS DURING NORMAL OPERATION

Emission limits are subject to the requirements of BACT. Refer to the Regulation XIII evaluations in the later sections for discussions of the appropriate BACT limits. The next table provides the applicable BACT emission limits for the combustion gas turbines. Also shown in the table are the equivalent emission levels in lbs/MMBtu and lbs/MMscf, which have been converted from the emission limits based on the heating value (1,010 Btu/scf) and the combustion gas turbine heat input rate.

Table 9 Emission Limits of the Combustion Gas Turbine, 36 °F, 60RH

Pollutant	Emissions (ppmv @15% O_2)	Emissions (lbs/MMBtu)	Emissions (lbs/MMscf)
NOx, prior to SCR	25(1)	0.090	90.6
NOx, after SCR	2.0(2), 1-hour average	0.007	7.25
CO, without duct burners firing	3.0(2), 1-hour average	0.007	6.62
CO, with duct burners firing	4.0(2), 1-hour average	0.009	8.82
ROG, without duct burners firing	1.1(4)	0.0014	1.39
ROG, with duct burners firing	2.0(2)	0.0025	2.52
SOx	0.14(2)(3)	0.0007	0.71
PM10(3)	----	0.0050(3)	5.01
NH3	5.0(2)	N/A	N/A

(1). Manufacturer provided data,

(2). BACT determined limits, 15% O_2, dry basis

(3). Applicant provided data, SOx is equivalent to 0.25 grain per 100 scf natural gas. See attached gas analysis data in Appendix I

(4). Applicant provided data, equivalent to 1.4 ppmv actual stack concentration

The next table is a summary of the emission limits for the auxiliary equipment.

Table 10 Emission Limits of the Auxiliary Equipment

Equipment	CO	NOx	PM10	ROG	SOx
Auxiliary Boiler	50 ppmv at 3% O_2(1)(3)	7 ppmv at 3% O_2(1)	7.6 lb/MMscf Natural Gas(1)	10 ppmv at 3% O_2(1)(3)	0.6 lb/MMscf Natural Gas(1)
Emergency Generator	2.0 gram /BHP-hr(1)(2)	1.5 gram /BHP-hr(1)(2)	0.16 gram /BHP-hr(2)	1.5 gram /BHP-hr(1)(2)	0.003 gram /BHP-hr(1)
Emergency Fire Pump	3.55 gram /BHP-hr(2)	5.89 gram /BHP-hr(2)	0.25 gram /BHP-hr(2)	1.0 gram /BHP-hr(1)(2)	0.17 gram /BHP-hr(1)

(1) BACT limits, from AP-42 or the District guidelines.
(2) Manufacturer provided data.
(3) Applicant provided data.

The ammonia (NH3) emission limit of the auxiliary boiler is 5 ppmv, corrected to 3% O2, dry basis.

HOURLY EMISSIONS RATES

Actual hourly emission rates can be derived from the emission levels specified in the previous tables. Detailed calculations are provided in the Appendix A. The next table shows a summary of the emissions from one gas turbine.

Table 11 Maximum Hourly Emissions – One Combustion Gas Turbine

Conditions	NOx		CO		PM10	ROG		SOx(4)
	lb/hr(1)	lb/hr(2)	lb/hr(1)	lb/hr(2)	lb/hr(3)	lb/hr(1)	lb/hr(2)	lbs/hr
Base Load, no Duct Burners Firing	13.01	13.01	11.83	7.92	9.0	2.49	2.49	1.28
Peak Load, with Duct Burners Firing	18.01	18.01	21.92	10.96	10.5	6.26	6.26	1.78
Warm Start(5)	80	80	100	100	9.0	16	16	1.78
Cold Start(5)	80	80	100	100	9.0	16	16	1.78

(1) Short term average, NOx level of 2.0 ppmv, CO of 3.0/4.0 ppmv
(2) Long term average, NOx level of 2.0 ppmv, CO of 2.0 ppmv
(3) PM10 includes both the front and back halves.
(4) Natural gas H2S concentration level of 0.25 grain per 100 scf.
(5) Warm start duration is 1 hour and cold start duration is 3 hours.

Emissions from the auxiliary equipment are calculated in the Appendix B and summarized in the next table.

Table 12 Maximum Hourly Emissions – Auxiliary Equipment

Equipment	CO (lb/hr)	NOx (lb/hr)	PM10 (lb/hr)	ROG (lb/hr)	SOx (lb/hr)
Auxiliary Boiler	4.64	1.07	0.97	0.53	0.09
Emergency Generator	6.47	4.85	0.52	4.85	0.01
Emergency Fire Pump Engine	2.64	4.38	0.19	0.74	0.13

30-DAY AVERAGE EMISSIONS OF NON-RECLAIM POLLUTANTS

Maximum daily and yearly emissions are calculated using the emission rates of the above tables, and are based on the following operating schedules provided in the application.

Table 13 Facility Operating Schedules

Daily Operating Schedule		Yearly Operating Schedule	
Daily hot start	1 hour	Yearly hot start	365 hours
Daily with duct burner	16 hours	Yearly with duct burner	5,100 hours
Daily without duct burner	7 hours	Yearly without duct burner	3,295 hours

The daily operating schedule dictates the emissions offset for criteria pollutants (ERC) while the yearly operating schedule affects the NOx RTC calculations. The potential to emit (PTE) of non-RECLAIM pollutants are calculated in Appendix C. The results are given in table C-7, and are shown in the next table.

Table 14 30-Day Average Emissions from One Gas Turbine

Pollutants	PTE (lbs/day)	Hourly Emission (lbs/hr)	Monthly Emission (lbs/month)	Yearly Emission (tons/year)
CO	342	14.24	10,255	61.5
PM10	248	10.33	7,440	44.6
ROG	138	5.75	4,141	24.8
SOx	40	1.67	1,200	7.2

Operating schedules of the auxiliary equipment are the followings:

Auxiliary Boiler:	3,000 hours per year
Emergency Generator:	52 hours per year
Emergency Fire Pump Engine:	52 hours per year

The emissions are calculated in Appendix B and are included in the facility total as shown in the next table.

Table 15 30-Day Average Non-RECLAIM Emissions, Entire Facility

Equipment	CO (lb/day)	PM10 (lb/ day)	ROG (lb/ day)	SOx (lb/ day)
Auxiliary Boiler	111	23	13	2
Emergency Generator	4	0	3	0
Emergency Fire Pump Engine	0	0	0	0
Gas Turbine No.1	342	248	138	40
Gas Turbine No.2	342	248	138	40
Facility Total	799	519	292	84

ANNUAL AVERAGE OF NOx EMISSIONS

The RECLAIM program requires that a facility shall provide RECLAIM trading credits (RTC) to offset the total facility NOx emissions for the first year of operation. First year NOx emissions are calculated in Appendix A and Appendix B. RTC requirements will be based on an 1:1 offset ratio of the actual NOx emissions. Since the first year includes the commissioning period NOx emissions during the commissioning period must be included. The estimation of the gas turbines annual NOx emissions assumes 365 hours of hot starts, 5,100 hours of peak load with duct burners, and 3,295 hours of base load without duct burners. Based on this schedule, the first year of operation is broken into the first month that includes commissioning and the rest 11 months of normal operations. Detailed RTC calculations are included in the Table C-8, Appendix C. Results are presented in the next table.

Table 16 NOx RTC Calculations – Entire Facility

Equipment	Hours	NOx RTC (lbs)	NOx RTC (lbs)*
1st Month (commissioning), One Turbine		116,929	89,614
Next 11 months (interim), One Turbine		1,614,633	153,842
First year operation, One Turbine	8,760	1,731,562	243,456
Two turbines subtotal		**3,463,124**	**486,912**
Auxiliary Boiler	3,000	3,201	3,201
Emergency Generator	52	252	252
Emergency Fire Engine	52	228	228
Grand Total		**3,466,805**	**490,593**

If the facility is able to certify the NOx CEMS right after the commissioning period, it will be able to monitor the NOx emissions through the use of the NOx CEMS. The NOx emissions may then be assumed at the control level and the NOx RTC requirements will be significantly different. The amount of NOx RTC required is calculated in Table C-9, Appendix C. Results are shown in the column with an asterisk sign of the above table.

NOx RTC required: <u>490, 593</u> lbs.

RULES EVALUATION

40CFR PART 60 SUBPART DA – NSPS FOR THE AUXILIARY BOILERS AND DUCT BURNERS

The auxiliary boiler is not subject to this performance standard because its maximum heat input of 129 MMBtu/hr is less than the 250 MMBtu/hr threshold established by this regulation.

The duct burners have a heat input rate of 697 MMBtu/hr and so are subject to the requirements of this regulation. Specifically for equipment consuming gaseous fuel the requirements are:

PM10 <= 0.03 lb/MMBtu
SOx <= 0.2 lb/MMBtu
NOx <= 0.2 lb/MMBtu

The application did not provide separate emission calculations for the duct burners. Rather, the duct burners are deemed as an integrate part of the combustion gas turbines. The same emission control apparatuses apply to both the duct burners and the combustion gas turbines. Therefore, the duct burners emissions are equivalent to the combustion gas turbines. The emission rates according to the data presented in Table 9 are:

PM10 = 0.0050 lb/MMBtu
SOx = 0.0007 lb/MMBtu
NOx = 0.0072 lb/MMBtu

Compliance with this regulation is demonstrated.

40CFR PART 60 SUBPART GG – NSPS FOR GAS TURBINES

NSPS applies to this project since the turbine heat input is greater than the 10.7 gigajoules per hour threshold. Actual unit rating is 1,813(10^6) Btu/hr X 1,055 joules/Btu = 1,913 gigajoules/hr. The applicable standards are determined in Appendix G, and the results are:

NOx = 98.3 ppmv
SOx = 150 ppmv

The application proposes NOx limit of 2.0 ppmv, and the facility will use natural gas of sulfur content less than 0.25 grains per 100 scf. Compliance is expected.

A performance test is required within 180 days of startup.

40CFR PART 63 – NESHAPS FOR STATIONARY GAS TURBINES

EPA is in the process of establishing a NESHAPS for gas turbines, and a rule may be scheduled for promulgation in 2002. Until the NESHAPS is promulgated, turbine MACT standards must be evaluated on a case-by-case basis. For this project, because HAP emissions for the IEEC turbines are below the major source thresholds of 10 tons per year (tpy) for a single HAP or 25 tpy for a combination of HAPs, the turbines are not considered major sources of HAP, and are exempt from this regulation. Detailed calculations of HAP emissions and Rule 1401 pollutants are included in Appendix D.

40CFR PART 64 - COMPLIANCE ASSURANCE MONITORING (CAM)

The CAM regulation applies to major stationary sources that use control equipment to achieve a specified emission limit. The rule is intended to provide a "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits. The turbines are major sources for NOx, CO, and ROG emissions, and will use control equipment to meet BACT limits for NOx and CO. The external control equipment for NOx and CO are the selective catalyst reduction (SCR) and oxidation catalysts. ROG emissions are controlled by the use of natural gas and by efficient combustor design, but not by use of an external device. Therefore, the CAM rule applies to NOx and CO emissions. Since there is no add-on control equipment used to meet the ROG limit this regulation would not apply for ROG.

Compliance with the BACT limits for NOx and CO will be through real time monitoring by CEMS. The NOx CEMS will be certified in accordance with Rule 2012 requirements and the CO CEMS will be certified in accordance with the Rule 218 requirements. Compliance with the ROG limit will be determined by periodic source testing. Compliance with this regulation is expected.

40CFR PART 72 – ACID RAIN PROGRAM

This facility is subject to the requirements of the Federal Acid Rain program. The facility is required to apply for a federal permit (Title IV). The acid rain program is similar to RECLAIM in that facilities are required to cover SO_2 emissions with "SO_2 Allowances" (similar to RTCs), or purchases of SO_2 on the open market. It is expected that the IEEC will purchase SO_2 allowance in the open market. The plant is also required to monitor SO_2 emissions through use of fuel gas meters and gas composition analysis (use of emission factors is also acceptable in certain cases) or with the use of exhaust gas CEMS. It is expected that IEEC will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with gas analysis.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The combined cycle facility requires CEQA certification by the California Energy Commission (CEC). Although the District is not the leading agency for CEQA certification, the applicant has submitted a CEQA application indicating it is pursuing CEQA certification with the lead agency. The requirements of a CEQA analysis are met under the CEC licensing procedure (01-AFC-17).

RULE 212 – STANDARDS FOR APPROVING PERMITS

This project is subject to Rule 212 public notice requirements because the daily maximum CO, NOx, PM10, and ROG emissions from the project will all exceed the emissions thresholds specified in subdivision (g) of this rule. The District will prepare the public notice and it will contain sufficient information to fully describe the project.

In accordance with subdivision (d) of this rule, the applicant is required to distribute the public notice to each address within ¼ mile radius of the project. The applicant has complied with the requirement, and provided AQMD with a list of households that were served.

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, and Section 124.10. The minimum requirements specified in the above documents are included in paragraphs (g)(1), (g)(2), and (g)(3).

In accordance with paragraph (g)(1) of this rule, the District has made the following information available for public inspection (at the City of Perris Cesar E. Chavez Library) during the 30-day comment period: public notice, project information submitted by the applicant, and the District's permit to construct evaluation.

In accordance with paragraph (g)(2) of this rule, the public notice needs to be published in a newspaper that serves the area that will be impacted by the project. The public notice was published on **Riverside Press Enterprise** on Tuesday, July 16, 2002.

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

After the public notice is published, there will be a 30-day period for submittal of public comments. AQMD has received comments from the US EPA, the Southern California Association of Governments (SCAG), the National Park Service, one citizen, and the applicant.

In addition to the above, and in accordance with federal requirements for PSD projects, a notice to the public regarding the development of a mailing list for this project (and two other PSD projects) was published in the following newspapers on September 17, 2001: LA Daily Journal, Riverside Press Enterprise, Daily News, and the Desert Sun. Persons who requested to be on the District's mailing list for this project will receive a copy of the public notice.

RULE 218 – CONTINUOUS EMISSION MONITORING

The IEEC facility will be required to install CO CEMS to verify compliance with the hourly concentration and monthly emission limits. The CO CEMS will need to comply with the requirements of Rule 218, and the facility will need to submit a CEMS application for AQMD review and approval prior to installing the CEMS. NOx emissions monitoring is discussed under RECLAIM rules.

RULE 401 – VISIBLE EMISSIONS
Visible emissions are not expected from the natural gas fired gas turbines, the boiler and the emergency generator under normal operating conditions. Even though the emergency fire pump engine is diesel fired compliance is still expected based on experience with similar equipment.

RULE 402 – NUISANCE
Nuisance from gas turbines and the auxiliary boiler are not expected under normal operating conditions. The ammonia storage tanks have very minimum emissions, and are not expected to have an odor problem. The facility has taken necessary steps to ensure an acceptable noise level.

RULE 403 – FUGITIVE DUST
This rule requires use of best available control measures to minimize fugitive dust formation from "active operations" including but not limited to, earth moving, construction, and vehicular movement. The rule prohibits active operations from causing visible emissions that extend beyond the facility's fence line. For this project IEEC has conducted a modeling analysis of the air quality impacts during the construction and demolition phase using the EPA approved ISCST3 model. With the exception of 24-hour and annual PM_{10} concentrations, the results of the modeling analysis indicate that the maximum construction and demolition impacts will be below the state and federal standards. The exception of PM10 emissions are due to the PM10 background emissions exceeding the state emissions standard.

IEEC has stated in the application that it plans to use best available control measures (BACT). Compliance with this rule is expected.

Table 17 Modeled Maximum Construction Impacts

Pollutants	Avg. Time	Maximum Impacts ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	State Standard ($\mu g/m^3$)	Federal Standard ($\mu g/m^3$)
NOx	1-Hour	230	211	441	470	-
	Annual	11	36	47	-	100
SOx	1-Hour	31	278	309	650	-
	24-Hour	5	92	97	109	365
	Annual	0.4	5	5	-	80
CO	1-Hour	299	12,650	12,949	23,000	40,000
	8-Hour	129	6,302	6,431	10,000	10,000
PM_{10}	24-Hour	80	139	219	50	150
	Annual, AGM*	6	44	50	30	-
	Annual, AAM*	6	50	56	-	50

* AGM – Annual Geometric Mean, AAM – Annual Arithmetic Mean

RULE 407 – LIQUID AND GASEOUS AIR CONTAMINANTS
This rule limits CO emissions to 2,000 ppmv, and SO_2 emissions to 500 ppm for equipment not subject to the emission concentration limits of 431.1. Since the turbines and the boiler are subject to the requirements of Rule 431.1, the sulfur limit is exempted. The CO limit of 2,000 ppmv of this rule does apply. The CO emissions will be controlled by an oxidation catalyst, and are expected to be less than 4 ppmv at 15% O_2 level for the turbines, and 50 ppmv at 3% O_2 for the boiler. Compliance is expected, and will be verified through CEMS data.

RULE 409 – COMBUSTION CONTAMINANTS
This rule limits PM emissions to 0.1 grain/scf. The equipment are expected to meet this limit based on the calculations shown below:

For the gas turbine, the PM10 emissions are 10.50 lb/hr for one turbine with the duct burners firing. Estimated exhaust gas using the data provided in Table 4:

Exhaust = 700, 387 DSCFM = 42 MMscf/hr

$$\text{PM10} = \frac{10.5 * 7000}{42 * 10^6} = 0.002 \text{ grain/dscf}$$

For the boiler similar calculation can be done using the emissions data calculated in Appendix A.

Exhaust = 1.277 MMscf/hr

PM10 = 0.97 lb/hr

$$\text{PM10} = \frac{0.97 * 7000}{1.277 * 10^6} = 0.0053 \text{ grain/scf}$$

Compliance will be verified through the initial performance test as well as by periodic testing as required by the Title V permit.

RULE 431.1 – SULFUR CONTENT OF NATURAL GAS
The pipeline quality natural gas to be supplied to the facility is expected to comply with the 16 ppmv sulfur limit (calculated as H_2S) specified by this rule. IEEC has provided a gas analysis (Refer to Appendix I) that demonstrated sulfur content of less than 0.25 gr/100 scf, which is equivalent to sulfur concentration of about 4 ppmv. It is also much less than the 1gr/100 scf limit typical of commercial grade natural gas. Compliance is expected.

RULE 475 – ELECTRIC POWER GENERATING EQUIPMENT
This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment must meet a limit for combustion contaminants (combustion contaminants are defined as particulate matter in AQMD Regulation I) of 11 lbs/hr or 0.01 grain/scf. Compliance is achieved if either the mass limit <u>or</u> the concentration limit is

met. Mass PM10 emissions from the IEEC turbines are estimated at 10.50 lbs/hr. However, on a concentration basis the estimated grain loading is less than 0.01 grain/scf for the turbines (see calculations under Rule 409 discussion.) Therefore, compliance is expected. Compliance will be verified through the initial performance test as well as periodic testing required by Title V.

REGULATION XIII – NEW SOURCE REVIEW

The IEEC power plant project is subject to new source review (NSR) that includes BACT requirements, modeling analysis, and offsets obligations. The following is a detailed discussion of each requirement. Requirements for NOx are discussed separately in Rule 2005 evaluation.

1. BACT (Best Available Control Technology)

BACT is defined in AQMD Rule 1301 as follows:

BACT means the most stringent emission limitation or control technique which:

- has been achieved in practice for such category or class of source; or
- is contained in any State Implementation Plan (SIP) approved by the US 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 that such limitations or control technique is not presently achievable; or
- 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.

This definition of BACT is consistent with the federal LAER definition.

A Gas Turbine and HRSG Duct Burner

BACT Limits Determined in the PDOC

At the time when the PDOC was drafted the BACT and the federal LAER for a combined cycle gas turbine were the followings:

NOx 2.5 ppmv, 1-hour average, corrected to 15% O_2
CO: 6.0 ppmv, 3-hour average, corrected to 15% O_2
ROG: 2.0 ppmv, 1-hour average, corrected to 15% O_2
SOx: natural gas with sulfur concentration as H_2S less than 1 grain per 100 scf
PM10: natural gas with sulfur concentration as H_2S less than 1 grain per 100 scf
NH3: 5.0 ppmv, 1-hour average, corrected to 15% O_2

These limits were consistent with the CARB document Guidance for Power Plant Citing and Best Available Control Technology (1999). AQMD has been using the CARB document and federal LAER as a reference for determination of applicable BACT levels. The following is a summary of the recommended BACT limits:

Table 18 BACT Levels Required by CARB and AQMD

NOx	CO	ROG	PM10	SOx	NH3
2.5 ppmv @ 15% O_2, dry basis, 1-hour rolling average, OR: 2.0 ppmv @ 15% O_2, dry basis, 3-hour rolling average	6 ppmv @ 15% O_2, dry basis, 3-hour rolling average	2 ppmv @ 15% O_2, 1-hour rolling average OR: AP-42 emission factor of 0.0021 lbs/MMBtu, High Heating Value*	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf AP-42 emission factor of 0.0066 lb/MMBtu, or: **6.67 lb/MMscf***	An emission limit corresponding to natural gas with fuel sulfur content of less than 1 grain /100 scf (no more than 0.55 ppmv @ 15% O_2) **(this equates to 2.85 lb/MMscf*)**	5.0 ppmv, dry basis, corrected to 15% O_2

* EPA AP-42, Table 3.1-2a, Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines.

IEEC proposed in the application the following BACT levels as shown in Table 19.

Table 19 IEEC Proposed BACT Levels

NOx	CO	ROG	PM10	SOx	NH3
2.5 ppmv @ 15% O_2, dry basis, 1-hour rolling average	6 ppmv @ 15% O_2, dry basis, 3-hour rolling average	2 ppmv @ 15% O_2, 1-hour rolling average	Use of natural gas with sulfur content of 0.25 grain/100 scf 11 lb/hr **(6.1 lb/MMscf)** without duct firing, 15.97 lb/hr with duct firing **(6.4 lb/MMscf)**	Use of natural gas with sulfur content of 0.25 grain/100 scf * **(this equates to 0.71 lb/MMscf)**	10 ppmv @15% O_2

* Sulfur content in natural gas provided by the Gas Company is limited to 1 grain per 100 scf. However, IEEC provided gas analysis data that indicated sulfur lever of 0.25 grain per 100 scf.

Subsequently the PDOC adopted BACT limits are summarized in the next table.

Table 20 AQMD Determined BACT Levels in PDOC

NOx	CO	ROG	PM10	SOx	NH3
2.5 ppmv @ 15% O_2, dry basis, 1-hour rolling average	6 ppmv @ 15% O_2, dry basis, 3-hour rolling average	2 ppmv @ 15% O_2, 1-hour rolling average	Use of natural gas with sulfur content of 0.25 grain/100 scf 11 lb/hr (**6.1 lb/MMscf)** without duct firing, 15.97 lb/hr with duct firing (**6.4 lb/MMscf)**	Use of natural gas with sulfur content of 0.25 grain/100 scf **(this equates to 0.71 lb/MMscf)**	5 ppmv @15% O_2

Calpine proposed the 10-ppmv ammonia slip level with the knowledge that the LAER/BACT level is at 5-ppmv. Two of its own facilities, Sutter and South Point, were permitted at 5 ppmv. Calpine indicated that these two facilities had experienced some difficulties in meeting the 5-ppmv NH3 level. It argued that 5-ppmv level was too stringent, and should not be considered as BACT on the ground that it is not achieved in practice.

The District has determined that the LAER/BACT for ammonia slip stands at 5-ppmv and it could not be relaxed to 10-ppmv. The 5 ppmv NH3 slip limit is consistent with the CARB's BACT guidelines. Although Calpine cited difficulties at its facilities, it did not demonstrate that the 5 ppmv limit was not achievable in other facilities. In fact, there are many facilities throughout the nation that have the NH3 slip level permitted at 5 ppmv, and are operating in compliance within the permit limit. The 5-ppmv level has been the LAER/BACT standard since 1999, and has been demonstrated as achieved in practice. Therefore, this facility must follow the LAER level, which is 5-ppmv.

In conclusion, the 5 ppm ammonia slip level is deemed as the BACT limit for this project based on the 1999 CARB BACT guidance document.

Final BACT limits for the FDOC

After the PDOC was released, AQMD received comments from the US EPA suggesting a different set of BACT limits. The EPA proposed limits are:

NOx: 2.0 ppmv, 1-hour rolling average, 15% O2, dry
CO: 4.0 ppmv, 1-hour rolling average, 15% O2, dry
ROG: 2.0 ppmv, 1-hour rolling average, 15% O2, dry

Meanwhile the Blackstone facility in Massachusetts has been operating with two ABB GT-24 combined cycle gas turbines under a permit condition of 2.0 ppmv NOx, dry basis at 15% O_2. In December 2002 the facility accumulated more than 181 days of operation under compliance, thus satisfying the BACT criteria of achieved in practice. Subsequently AQMD moved in January 2003 to establish new BACT limits for combined cycle gas turbines. The AQMD proposed new BACT limits are:

NOx: 2.0 ppmv, 1-hour rolling average, 15%O2, dry
CO: 3.0 ppmv, 1-hour rolling average, 15%O2, dry

AQMD's Scientific Review Committee has reviewed the new limits, and has issued a public notice soliciting comment from the public. It is anticipated that the new BACT limits will be adopted.

AQMD communicated the EPA comments and the proposed new BACT limits to the IEEC. The IEEC hold several discussions with AQMD, and has agreed in principle with the more stringent BACT limits. It also raised several concerns specific to the GE 7FB gas turbines and the HRSG duct burners. These issues include:

- Compliance with the NOx limit during load changes initiated by California Independent System Operator, activation of safety protection system, initiation and shutdown of the combustion gas turbines, duct burners, the steam turbine, inlet air cooling fogging system, and other unforeseen conditions that would not qualify as "breakdown."
- Compliance with the CO limit when the duct burners are fired. The duct burners have a very high heat input rate (697 MMBtu/hr), and there have not been sufficient data to demonstrate that the 3 ppmv limit is achieved in practice.

AQMD agrees to allow certain qualified operating conditions in which compliance with the 2.0 ppmv limit is excluded, for up to fifteen 1-hour periods per rolling 12-month period. The qualified conditions are clearly defined, and do not include operator errors. The qualified conditions must be recorded within 24 hours, and must be logged in CEMS by five PM of the next business day. AQMD also agrees that the CO limit shall be 4 ppmv when the duct burners are fired. The definition and requirement of the qualified operating conditions are included in the conditions section.

The following table is a summary of the BACT limits for this project:

Table 21 AQMD Determined BACT Levels in PDOC

NOx	CO	ROG	PM10	SOx	NH3
2.0 ppmv @ 15% O_2, dry basis, 1-hour rolling average	3 ppmv without duct firing, 4 ppmv with duct firing, 15% O_2, dry basis, 1-hour rolling average	2 ppmv @ 15% O_2, 1-hour rolling average	Use of natural gas with sulfur content of 0.25 grain/100 scf 9 lb/hr (**5.05 lb/MMscf**) without duct firing, 10.5 lb/hr with duct firing (**4.44 lb/MMscf**)	Use of natural gas with sulfur content of 0.25 grain/100 scf **(this equates to 0.71 lb/MMscf)**	5 ppmv, 1-hour average, dry basis, @15% O_2

B Auxiliary Boiler

BACT for a natural gas fired boiler with SCR and CO catalyst is summarized in the next table:

Table 22 BACT Requirements for the Auxiliary Boiler

Emissions	BACT	Applicant Proposed	Most Stringent Level
NOx	7.0 ppmv at 3% O_2	9.0 ppmv at 3% O_2	7.0 ppmv at 3% O_2
CO	50 ppmv at 3% O_2	50 ppmv at 3% O_2	50 ppmv at 3% O_2
ROG	Natural gas, 5.5 lb/MMscf(1), or 13.3 ppmv at 3% O_2	10 ppmv at 3% O_2	10 ppmv at 3% O_2
PM10	Natural gas, 7.6 lb/MMscf(1)	Natural gas	7.6 lb/MMscf
SOx	Natural gas	H_2S <0.25 gr/100 scf, equivalent to SOx of 0.71 lb/MMscf	0.71 lb/MMscf
NH3	5.0 ppmv at 3% O_2	10 ppmv at 3% O_2	5 ppmv at 3% O_2

(1) AP-42 data

The NOx level proposed by the applicant does not meet the BACT level. The 7.0 ppmv NOx level will be implemented. The applicant has agreed to the 7.0 ppmv NOx limit.

C Emergency Generator

BACT for a natural gas fired emergency generator (stationary IC engine) and the facility proposed emission limits are listed in the next table:

Table 23 BACT Requirements for the Emergency Generator

Emissions	BACT(1)	Applicant Proposed	Most Stringent Level
NOx	1.5 gram/BHP-hr	1.5 gram/ BHP-hr	1.5 gram/ BHP-hr
CO	2.0 gram/ BHP-hr	2.0 gram/ BHP -hr	2.0 gram/ BHP-hr
ROG	1.5 gram/ BHP-hr	1.5 gram/ BHP -hr	1.5 gram/ BHP-hr
PM10	Natural gas	0.16 gram/ BHP -hr	0.16 gram/ BHP-hr
SOx	Natural gas	0.003 gram/ BHP -hr	0.003 gram/ BHP-hr

(1) District Guidelines

As shown in the above table, the applicant proposed levels meet BACT requirement.

D Emergency Fire Pump Engine

BACT for the diesel fired emergency generator (stationary IC engine) and the facility proposed emission limits are listed in the next table:

Table 24 BACT Requirements for the Emergency Fire Pump Engine

Emissions	BACT(1)	Applicant Proposed	Most Stringent Level
NOx	6.9 gram/ BHP -hr	5.89 gram/ BHP -hr	5.89 gram/ BHP -hr
CO	8.5 gram/ BHP -hr	3.55 gram/ BHP -hr	3.55 gram/ BHP -hr
ROG	1.0 gram/ BHP -hr	1.0 gram/ BHP -hr	1.0 gram/ BHP -hr
PM10	0.38 gram/ BHP -hr	0.25 gram/ BHP -hr	0.25 gram/ BHP -hr
SOx	Fuel sulfur content < 0.05% by weight	0.25 gram/ BHP -hr	0.25 gram/ BHP -hr

(1) District Guidelines

In addition, BACT requires use of low sulfur diesel. The sulfur content shall not exceed 0.05% in weight. Starting June 1, 2004, sulfur content shall not exceed 15 ppmw.

2. MODELING

Modeling is required for CO and PM10 emissions per Rule 1303(b). Rule 1303 requires that through modeling, the applicant must substantiate that the project does not exceed the most stringent ambient air quality standard or cause a significant change in air quality concentration.

Maximum project impacts from CO and PM10 emissions were determined by using the ISCST3 model. The background meteorological data used in the modeling analysis were from the Riverside monitoring stations. The next table shows the applicable standards for the subject pollutants and the results from IEEC modeling analysis. PM10 emissions from the cooling towers are not included since it is exempted by Rule 219.

Table 25 New Source Review Modeling – Facility Impacts

Pollutants	Averaging Time	IEEC Model Results ($\mu g/m^3$)	Background Concentrations ($\mu g/m3$)	Total Impact ($\mu g/m3$)	Most Stringent Air Quality Standard ($\mu g/m3$)
CO	1-hour	792.8	12,650	13,443	23,000
	8-hour	418.7	6,302	6,721	10,000
PM10	24-hour	9.9	139	148.9	50
	Annual (a)	1.4	44	45.4	30

(a) Annual Geometric Mean (AGM)

The PM10 24-hour average and annual average background concentration exceeds the most stringent air quality standard (California air quality y standards). The area is therefore not in attainment for PM10 emissions. Per Rule 1303, PM10 emissions of each equipment from this project must not cause the significant change in air quality defined in Rule 1303. The next table shows the modeling results of one set of gas turbine/HRSG.

Table 26 New Source Review Modeling – One Turbine/HRSG*

Pollutant	Averaging Time	IEEC Model Results ($\mu g/m^3$)	Significant Change in Air Quality Concentration ($\mu g/m^3$)	Significant under Federal PSD
CO	1-hour	55.9	2,000	No
	8-hour	304.0	500	No
PM10	24-hour	2.48	2.5	No
	Annual (a)	0.5	1.0	No

* Results are taken from Table 5.2-24 (Revised 2/01/02) of the AFC

The emission increases of CO and PM10 are below the significant change levels, and are acceptable.

Calpine submitted two air quality modeling analyses to the District for review. The District deemed the initial air quality model analysis (dated August 2001) as not acceptable for Rule 1303 requirements. The deficiencies of the initial modeling results are described in the memo from Mike Nazemi to Pang Mueller on January 16, 2002. Subsequently, Calpine submitted the second air quality model analysis, date February 20, 2002, to the District. The District found the second analysis acceptable for Rule 1303 requirements. Refer to the memorandum by Yi-Hui Huang of March 15, 2002 for detailed comments.

3. OFFSETS

Offsets for Non-RECLAIM pollutants are calculated based on a calendar month average emissions in accordance with Rule 1306(b). Offset calculations are provided in the Appendix C. The facility meets the definitions of an Electrical Generating Facility (EGF) as defined in Rule 1309.1. As so, it qualifies to offset the emissions from the priority reserve if ERCs could not be purchased from the open market. If the facility elects to do so, it is obligated to follow the requirements of Rule 1309.1(a). The requirements include getting the facility fully and legally operational at the rated capacity within 3 years following issuance of a Permit to Construct or the California Energy Commission certification, whichever is later, subject to an extension by the Executive Officer consistent with SCAQMD Rule 205. It also requires that the facility must use up its existing ERCs before it could tap into the priority reserve. For an electrical generating facility ROG can not be offset through priority reserve.

The next table is a summary of the facility wide requirement for non-RECLAIM pollutant offsets. Refer to Appendix C for details of offset calculations.

Table 27 Facility Offset Requirement

Equipment	CO	ROG	PM10	SOx
Gas Turbines	684	276	496	40
Auxiliary Boiler	111	13	23	2
Emergency Equipment	4	3	0	0
Total ERC Required (if offset from the Priority Reserve)	799	292	**519**	**82**
Total ERC Required (if not from the Priority Reserve, offset ratio of 1.2)	**959**	**350**	623	98

The facility has indicated that it will provide SOx offset through the Priority Reserve, and CO and ROG offsets through regular ERCs. It has submitted an application that proposes to generate PM10 ERCs through a road paving program. The application is currently under AQMD review. If approved, the application will generate sufficient PM10 ERCs for use in this project. If the application does not receive AQMD approval the facility will provide PM10 offsets through the Priority Reserve. Tentatively we will assume the PM10 will be offset through the Priority Reserve.

The facility offset requirements are then:

CO: 959 lbs/day
ROG: 350 lbs/day
PM10: 519 lbs/day, from Priority Reserve

SOx: 82 lbs/day, from Priority Reserve

IEEC has purchased the following offsets for this project:

A) CO ERCs

Table 28 CO ERCs Acquired by IEEC

ERC Certificate Number	Company	City	Quantity (lbs/day)
AQ003178	Calpine Corporation	Los Angeles	677
AQ004233	Inland Valley Development Agency	Riverside	144
AQ004222	San Bernardino International Airport Authority	San Bernardino	3
AQ004417	Shell Oil	Los Angeles	2
	Total		826
	Required (based on an offset ratio of 1.2:1)		959

Therefore, additional CO ERCs of 133 lbs are required.

B) ROG ERCs

IEEC has enough ROG ERCs through its owner Calpine to satisfy the ROG offset requirement.

Table 29 ROG ERCs Acquired by IEEC

ERC Certificate Number	Company	City	Quantity (lbs/day)
AQ003069	Calpine Corporation	Los Angeles	1,473
	Total		1,473
	Required (offset ratio of 1.2:1)		350

RULE 1401- CARCINOGENIC AIR CONTAMINANTS

This rule specifies limits for maximum individual cancer risk (MICR), cancer burden, and non-cancer acute and chronic hazard indices (HI) from new permit rules, relocations, or modifications to existing permits which emit toxic air contaminants (TAC).

Rule 1401 requirement levels are the follows:

Table 30 Toxic Air Contaminants Requirements

Parameters and Specifications	Requirements
MICR, without T-BACT	<= $1 X 10^{-6}$
MICR, with T-BACT	<= $1 X 10^{-5}$
Cancer Burden	<= 0.5
Maximum Chronic Hazard Index	<= 1.0
Maximum Acute Hazard Index	<= 1.0

The applicant conducted a screening health risk assessment (SHRA) to evaluate potential impacts on public health of the TOC released from this project. The SHRA includes determination of MICR, acute and chronic hazard indices. The California Air Resource Board (CARB)/Office of Environmental Health and Hazard Assessment (OEHHA) computer program was used to evaluate multi-pathway exposures to toxic substances. Refer to Appendix D for a detailed description of the Rule 1401 calculations.

The District has reviewed the screening health risk assessment (SHRA), and it has deemed the assessment acceptable to the requirements of Rule 1401. The District's opinion is included in the memo from Mike Nazemi to Pang Mueller on January 16, 2002.

The following is a summary of the SHRA results.

Table 31 Modeling Results – Toxic Air Contaminants Emissions

Parameters and Specifications	Requirements
MICR	$0.3 X 10^{-6}$
Cancer Burden	0.0196
Maximum Chronic Hazard Index	0.048
Maximum Acute Hazard Index	0.06

RULE 1404 – HEXAVALENT CHROMIUM FOR COOLING TOWERS

Hexavalent chromium-containing water treatment chemicals will not be used in the new cooling towers. This rule prohibits the use of Cr^{+6} in the cooling water. Therefore, it is in compliance.

RULE VII- PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The South Coast Air Basin where the project is to be located is in attainment for NOx and SO_2 emissions. Therefore, a PSD analysis for these pollutants must be conducted.

For a new major facility, Rule 1702 defines a significant emission increase of NOx or SO_2 as an increase of greater than 25 tons per year (tpy). The new facility will emit approximately 166.7 tpy of NO_2 and 13.9 tpy of SO_2, according to emission calculations of Appendix A (assuming that all NOx is NO_2.) Thus, NO_2 emissions qualify for the significant increase definition, and are subject to PSD review. PSD review for SO_2 emissions is not required since the emissions of 13.9 tpy are less than the 25-tpy threshold.

The requirement for public notice (Rule 1710) is combined with the requirements of Rule 212. The AQMD will publish public notices according to the requirements of this regulation in a newspaper that serves the area that will be impacted by the project.

Requirement for a significant emission increase under Rule 1703 included the following:

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

For BACT determinations please refer to Rule 2005 evaluation.

As required by this rule, the District sent the PSD analysis and modeling materials to the following affected officials on November 29, 2001:

Gerardo Rios, US EPA, Region IX
John Notar, Federal Land Manager (FLM)
Mike McCorison, State Land Manager
Chris Holbeck, National Park Service, Joshua Tree National Park
Anne Fege, Forest Supervisor, Cleveland National Forest, US Forest Service
Gene Zimmerman, Forest Supervisor, San Bernardino National Forest, US Forest Service
Jody Cook, Forest Supervisor, Angeles National Forest, US Forest Service

AQMD received comments from Mike McCorision on December 17, 2001. The comments were forwarded to the applicant for response. The IEEC addressed the comments on February 15, 2002 in a letter to AQMD. As a part of the response a revised modeling analysis was submitted to AQMD along with the letter. AQMD sent the new modeling analysis and applicant comments to the above listed officials on March 1, 2002. No further comments have been received.

After the PDOC was released and during the subsequent 30-day commenting period Mike McCorison and John Notar conducted a detailed review of the air quality analysis, and raised several questions about the modeling approaches and assumptions. The FLM comments were sent to the applicant. Following the guidelines provided by the FLM comments, The IEEC conducted a new set of modeling. The modeling analysis was submitted to the FLM for review. The FLM deemed the analysis adequate in the letter from Jack Blackwell of US Forest Service to Pang Muéller on January 24, 2003.

The following methodology was used in performing the PSD analysis.

1. Determine whether pre-construction monitoring is required
2. Assessment of significance under PSD
3. Determine ambient air quality impacts
4. Determine impacts in Class I areas

The application submitted modeling results that showed the maximum NO_2 impacts of 0.5 $\mu g/m^3$ on an annual basis. Since this level does not exceed the pre-construction monitoring threshold of 14 $\mu g/m^3$, pre-construction monitoring is not required, and that monitoring data from nearby monitoring stations can be used to determine ambient air quality.

The modeled impact of 0.5 $\mu g/m^3$ was also compared to the PSD significance threshold of 1.0 $\mu g/m^3$. Since the new facility does not exceed the significance threshold, an increment consumption analysis is not required.

The ambient air quality impact analysis was included in Rule XIII evaluation. Refer to that section for a discussion of results.

The impacts on Class I areas were analyzed. There are six Class I areas within 100 km of the proposed new facility. They are:

Aqua Tibia Wilderness Area (33.5 km)
San Jacinto Wilderness Area (43.0 km)
San Gorgonio Wilderness Area (46.0 km)
Cucamonga Wilderness Area (64.5 km)
Joshua Tree National Park (70.5 km)
San Gabriel Wilderness Area (86.0 km)

Impacts of NO_2, SO_2 and PM10 on these areas were modeled. The results are shown in the next table. The results indicate that the maximum impacts are below the PSD Class I Increment for all pollutant in all areas.

Table 32 Maximum Impact – Class I Areas

Class I area	NO_2 Annual $\mu g/m^3$	SO_2 Annual $\mu g/m^3$	SO_2 24-hour $\mu g/m^3$	SO_2 3-hour $\mu g/m^3$	PM10 Annual $\mu g/m^3$	PM10 24-hour $\mu g/m^3$
PSD Class I Increment	2.5	2	5	2.5	5	10
Aqua Tibia	0.05	0.005	0.04	2	0.05	0.4
San Jacinto	0.02	0.002	0.02	0.1	0.02	0.2
San Gorgonio	0.002	0.0001	0.004	0.02	0.002	0.05
Cucamonga	0.0006	0.00005	0.002	0.009	0.0008	0.02
Joshua Tree	0.02	0.001	0.01	0.09	0.01	0.14
San Gabriel	0.006	0.0005	0.01	0.05	0.006	0.09

A visibility analysis was also conducted for the closest Class I area, the Aqua Tibia Wilderness Area. The analysis is applicable to all other Class I areas. The results are shown in the next table.

Table 33 Visibility Analysis – Class I Areas

Class I Area	Back-ground	Theta	Azimuth	Distance	Alpha	Total Color Contrast Value (Delta-E)		Plume Contrast Value	
						Criteria	Plume	Criteria	Plume
Aqua Tibia	Sky	10.0	140	44.8	29	2.0	0.333	0.05	0.000
Wilderness	Sky	140.0	140	44.8	29	2.0	0.674	0.05	-0.009
Area	Terrain	10.0	84.0	33.5	84.0	2.0	1.220	0.05	0.008
	Terrain	140.0	84.0	33.5	84.0	2.0	0.312	0.05	0.003

Clearly the visibility impact is below the acceptable change limits of 5%.

AQMD modeling staff has reviewed the modeling and determined the analysis was acceptable. Please refer to the Memo by Yi-Hui Huang on March 15, 2002 for a detailed description.

RULE 2005 – NSR FOR RECLAIM

Rule 2005 applies to the NOx emissions from the turbines (including the duct burners.) This rule requires new sources to provide emission offsets in the form of RTCs, perform a modeling analysis, and meet the requirements of BACT. Each of the requirements is discussed in details as below:

1. BACT

For the IEEC project, a "top-down" BACT analysis was performed by following the guidance provided in EPA's October 1990 Draft New Source Review Workshop Manual. There are five basic steps of the top down approach:

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

The following is a detailed description of each step.

Step 1. Identify All Control Techniques

The following potential control techniques were identified for the IEEC gas turbines:

- Water/Steam Injection
- Dry Low-NOx combustor design (DLN)
- Catalytic combustors (i.e. XONON)
- Selective non-catalytic reduction (i.e. ammonia or urea injection)
- Non-selective catalytic reduction (i.e. 3-way catalyst)
- SCR
- SCONOx

Step 2. Eliminate Technically Infeasible Options

The applicant has determined that the following technologies are infeasible options.

Catalytic Combustors

The XONON combustors have been commercially demonstrated in a 1.5 MW natural gas fired turbine in California, and commercial availability of the technology in a 200 MW GE Frame 7G was recently announced. However, GE has indicated that the use of XONON technology is not commercially available for the IEEC project. No other turbine vendor has indicated the commercial availability of catalytic combustion systems. Therefore, it was determined that catalytic combustion controls are not technologically feasible for this project because of the lack of commercial availability.

Selective Non-Catalytic Reduction

SNCR involves the injection of ammonia or urea directly into the exhaust gases without use of a catalyst. This technology requires exhaust temperatures in the range of 1,200 °F to 2,000 °F and is mainly associated with boilers or heaters NOx control. The exhaust gas temperature for the IEEC turbines will be in the range of 1,087 °F to 1,200 °F, generally well below the required temperature for effect use of this technique.

Non-Selective Catalytic Reduction (NSCR)

This technique uses a catalyst without injected reagents to reduce NOx emissions. It is typically used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/ rhodium catalyst. NSCR is only effective in a stoichiometric or fuel rich environment where combustion gas is nearly depleted of oxygen. Gas turbine combustion is generally fuel lean and there is plenty of excess oxygen. Typical oxygen concentration in turbine exhaust is about 14 to 16 percent. Therefore, NSCR is not feasible for the IEEC turbines.

Step 3. Evaluation of Feasible Technologies

Excluding the deemed infeasible technologies, the following control types remain:

- Water/Steam Injection
- Dry Low-NOx combustor design (DLN)
- SCR
- SCONOx

The pros and cons of each control are discussed below:

Water/Steam Injection versus Dry Low-NOx Combustor (DLN)

IEEC has determined that DLN combustors were preferable to water or steam injection due to the superior emission control performance, additional CO and ROG benefits, and increased efficiency of the DLN technology. IEEC will utilize DLN combustors for this project.

SCR versus SCONOx

Both the SCR and the SCONOx are commercially available and technologically feasible for NOx control of the IEEC gas turbines. SCONOx has been demonstrated on a 22 MW turbine at the Sunlaw facility in Vernon, CA. Based on the data acquired from the NOx CEMS, SCONOx is capable of achieving a NOx level of 2.5 ppmv, 1-hour average, dry basis at 15% O_2. SCR can also achieve the 2.5 ppmv 1-hour average NOx limit. Furthermore, it has been demonstrated in the Blackstone facility in Massachusetts that SCR is capable of achieving the 1-hour average of 2.0 ppmv, dry basis at 15% O_2. AQMD moved in January 2003 to establish NOx BACT at 2.0 ppmv, 1-hour average, dry at 15% O_2. Due to the ability to achieve the 2.0 ppmv NOx limit SCR is superior to SCONOx.

IEEC has selected to use the SCR system in conjunction with DLN combustors for NOx control for the turbines. The turbine emissions will meet a 2.0 ppm NOx level, 1-hour average, dray basis at 15% O2. This level is deemed to meet the BACT requirements for this project.

As a conclusion, Dry Lean NOx combustion coupled with SCR is selected as BACT for NOx emission control.

2. MODELING

Modeling is required for NOx emissions per Rule 2005(c)(1)(B). Rule 2005 requires that through modeling, the applicant substantiate that the project does not exceed the most stringent ambient air quality standard nor cause a significant change in air quality concentration. Since the South Coast Air Basin is in containment with NOx emissions the impacts of the facility must not exceed the most stringent air quality standard. Maximum project impacts of NOx emissions were determined using the SCREEN3 model for 1-hour impacts, and ISCST3 model for the annual standard. Table 33 below shows the applicable standards and the results from IEEC modeling analysis for the entire facility. As discussed in Appendix D, model inputs for NO_2 assumed a 2.0 ppmv NOx concentration for the estimate of long-term (i.e. annual) impacts.

Maximum one-hour impacts assumed one turbine in start-up mode and one turbine in base load operation with duct burners firing.

Table 34 New Source Review NOx Modeling, Entire Facility

Pollutant	Averaging Time	IEEC Model Results ($\mu g/m^3$)	Background Concentrations ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Most Stringent Air Quality Standard ($\mu g/m^3$)	Results
NO_2	1-hour	244.3	211	455.3	470	Acceptable
	Annual	0.5	36	36.5	100	Acceptable

Rule 2005 (and Rule 1303) also requires modeling analysis for plume visibility. Refer to the results presented in the PSD analysis section for details. The results are acceptable.

3. OFFSET

Rule 2005(b)(2)(A) requires that a new facility provide sufficient RTCs to offset the emissions prior to the first year of operation on a 1-to-1 basis. Furthermore, paragraph (b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). The IEEC Plant is expected to begin operation in July 2005, and since the facility is located in Zone 2, RTCs may be obtained from either Zone 1 or Zone 2.

The amount of RTCs required is shown in Table C-8 and Table C-9 of Appendix C. The total required RTCs include the emissions from the gas turbines, the boiler, and emergency equipment. The acquired RTCs are summarized in Table 36, and they are not sufficient to cover estimated NOx emissions.

Table 35 NOx RTCs Acquired by the IEEC

Compliance Year	Zone	Cycle	Quantity Purchased (lbs)
2005-2010	Coastal	1	38,234
Total Purchased			38,234
Total Required			3,466,805
Total Required if CEMS Certified after Commissioning			490,593
Additional Minimum RTC Required			452,359

4. ADDITIONAL REQUIREMENTS FOR MAJOR SOURCES

Rule 2005 requires that a major source also comply with the following:

- Certify that all major sources in the state under control of the applicant are in compliance with all applicable federal emissions standards.
- Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source.
- Conduct a visibility analysis.

IEEC has 1) certified on the 400A form that all major sources under their control in the state comply with federal regulations, 2) done an alternative analysis under the AFC process, and 3) conducted a visibility analysis under NSR and PSD. Therefore, the above 3 requirements have been met.

RULE 2012 – MONITORING RECORDING AND RECORD KEEPING FOR RECLAIM

The IEEC facility will be a RECLAIM facility for NOx emissions. The new turbines and the auxiliary boiler will be classified as NOx major sources for RECLAIM purposes. As such each major source will be required to have a certified NOx CEMS, a totaling fuel meter, and emissions must be reported to the District through a RTU on a daily basis. IEEC will have twelve (12) months from the date of installation of the turbines to install the required emission monitor and have them certified. The facility must submit a CEMS application and plan for AQMD review and approval prior to receiving final certification on the CEMS.

During the interim period before the CEMS is certified, the NOx emissions factor is higher. According to the calculations of Appendix A, Table A-16, the emissions factor shall be 14.03 lb/MMscf.

REGULATION XXX – TITLE V

The subject facility will be subject to Title V requirements because the potential to emit for VOC, NOx, CO and PM10 will exceed the thresholds specified in Rule 3001. The requirements for the issuance of an initial Title V permit are as follows:

1. Deem application package either complete or incomplete within 30 days of receipt of the application package
2. Prepare a draft permit for facility review
3. Complete the proposed permit for EPA and Public Review
4. Notify EPA and the affected states, and publish the notice in a newspaper
5. Hold public hearing (if requested)
6. Finalize proposed permit and submit the public comments to the EPA
7. Issue final permit

The application package has been evaluated and it has been determined that the proposed equipment will comply with all applicable federal, state, and AQMD rules.

RECOMMENDATION

Based on the above engineering evaluation the District has reached a preliminary determination that this facility is expected to achieve compliance with all applicable rules and regulations. The final determination of compliance is contingent upon several requirements, which include providing additional offsets as required, conducting public notice, approval of EPA review, and CEC certification. It is recommended that the District issue a Permit to Construct and a temporary Permit to Operate. The equipment shall be included in the Section H of the facility permit, subject to the following conditions.

CONDITIONS

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:

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

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]

F14-1. The operator shall not use diesel 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 oil 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]

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

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

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

[40 CFR 68 - Accidental Release Prevention]

EQUIPMENT CONDITIONS

1-1. The operator shall limit the operating time to no more than 200 hours per year.

[Rule 1110.2, Rule 1304-Excemptions, Rule 2012]

[Devices subject to this condition: D9, D10]

12-1. The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).

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 twelve months.

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: **C4**, **C5**, C6]

12-2. The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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

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

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: **C4**, **C5**, C6]

12-3. The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

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

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

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: **C4**, **C5**, C6]

12-4. The operator shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of the engine.

[Rule 1110.2, Rule 1304-Excemptions, Rule 2012]

[Devices subject to this condition: D9, D10]

12-5. The operator shall install and maintain a non-resettable elapsed fuel meter to accurately indicate the engine fuel consumption.

[Rule 1110.2, Rule 1304-Excemptions, Rule 2012]

[Devices subject to this condition: D9, D10]

23-1. The equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1171

[Rule 1171]

[Devices subject to this condition: Rule 219 Exempted Cleaning Equipment]

29-1. The operator shall conduct source test(s) for the pollutant(s) identified below.

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

SOx emissions	Approved District Method	District Approved Avg. Time	Fuel Sample
ROG emissions	Approved District method	1 hour	Outlet of the SCR
PM emissions	Approved District Method	District Approved Avg. Time	Outlet of the SCR
NH3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR

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

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

The test shall be conducted in accordance with a District approved source 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 District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit. For natural gas fired turbines only, this shall be demonstrated by the following test method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400 - 500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees F. The use of this alternative method does not mean that it is more accurate than 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 VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. Because the BACT level was set using data derived from various source test methods, this alternate method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results must be reported with two significant digits.

The test shall be conducted with and without duct firing when this equipment is operating at loads of 100, 75, and 50 percent of maximum load for the NOx, CO, ROG and ammonia tests. For all other pollutants, the test shall be conducted with and without duct firing at 100% load only.

[Rule 1303 – BACT, Rule 1303 – Offsets, Rule 2005 – BACT, Rule 2005 - Offsets, Rule 1401]

[Devices subject to this condition: D1, D2, D3, D14, D21]

29-2. The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Avg. Time	Test Location
SOx emissions	Approved District Method	District Approved Avg. Time	Fuel Sample
ROG emissions	Approved District method	1 hour	SCR Outlet
PM emissions	Approved District Method	District Approved Avg. Time	SCR Outlet

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

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

The test shall be conducted 1) when the gas turbine and the duct burners are operating simultaneously at 100 percent of maximum heat input and 2) when the gas turbine is operating alone at 100 percent of maximum heat input.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit. For natural gas fired turbines only, this shall be demonstrated by the following test method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400 - 500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees F. The use of this alternative method does not mean that it is more accurate than 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

<u>determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. Because the BACT level was set using data derived from various source test methods, this alternate method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results must be reported with two significant digits.</u>

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

[Rule 1303 – BACT, Rule 1303 – Offsets]

[Devices subject to this condition: D1, D2, D14, D21]

29-3 The operator shall conduct source test(s) for the pollutant(s) identified below.

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

The test shall be conducted and the results submitted to the District within 60 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 days prior to the test.

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

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

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: **C4**, **C5**, C6]

40-1. 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 (lbs/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

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

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

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

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005]

[Devices subject to this condition: D1, D2, D14, D21]

40-2. The operator shall provide to the District a source test report in accordance with the following specifications:

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

Emission data shall be expressed in terms of concentration (ppmv), corrected to 3 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

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

All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.

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

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005]

[Devices subject to this condition: D3]

63-1. The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
CO	21, 510 LBS IN ANY 1 MONTH
PM10	14, 880 LBS IN ANY 1 MONTH
ROG	8, 578 LBS IN ANY 1 MONTH
SOx	2, 400 LBS IN ANY 1 MONTH

For the purpose of this condition, the limits shall be based on the combined emissions from equipment D1 (gas turbine), D2 (gas turbine), D14 (duct burner), and D21 (duct burner).

The operator shall calculate the emission limit(s) by using monthly fuel use data and the following emission factors: PM10 with duct burners firing 4.23 lbs/MMscf, PM10 without duct burners firing 5.01 lbs/MMscf, ROG with duct burners firing 2.52 lbs/MMscf, ROG without duct burners firing 1.39 lbs/MMscf, SOx 0.71 lbs/MMscf with and without duct burner firing.

The operator shall calculate the emission limit(s) for CO, during the commissioning period, using fuel consumption data and the following emission factor: 127.87 lb/MMscf.

The operator shall calculate the emission limit(s) for CO, after the commissioning period and prior to the CO CEMS certification, using fuel consumption data and the following emission factor: 19.93 lbs/MMscf.

The operator shall calculate the emission limit(s) for CO, after the CO CEMS certification, based on readings from the certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated in accordance with the approved CEMS plan.

[Rule 1303 – Offsets]

[Devices subject to this condition: D1, D2, D14, D21]

63-2. The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
CO	3, 330 LBS IN ANY 1 MONTH
PM10	690 LBS IN ANY 1 MONTH
ROG	390 LBS IN ANY 1 MONTH
SOx	60 LBS IN ANY 1 MONTH

The operator shall calculate the emission limit(s) by using monthly fuel use data and the following emission factors: CO 36.25 lb/MMscf, PM10 7.58 lbs/MMscf, ROG 4.14 lbs/MMscf, SOx 0.70 lbs/MMscf.

The operator shall calculate the emission limit(s) for CO, after the CO CEMS certification, based on readings from the certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated in accordance with the approved CEMS plan.

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005]

[Devices subject to this condition: **D3**]

67-1. 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

[Rule 2012]

[Devices subject to this condition: D1, D2, D14, D21]

67-2. The operator shall keep records, in a manner approved by the District, for the following parameters or items.

Date of operation, the elapsed time, in hours, and the reason for operation.

Records shall be kept and maintained on file for a minimum of two years and made available to district personnel upon request.

[Rule 1110.2, Rule 1304-Excemptions]

[Devices subject to this condition: D9, D10]

67-3. 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]

[Devices subject to this condition: Rule 219 Exempted Coating Equipment]

82-1. 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 will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The CEMS shall be installed and operated, 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.

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

The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine.

[Rule 1303 – BACT, Rule 1303 – Offset, Rule 218]

[Devices subject to this condition: D1, D2, D14, D21]

82-2. The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration is expressed in ppmv

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

The CEMS shall be installed and operating no later than 12 months 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 startup date, the operator shall provide written notification to the District of the exact date of start-up.

[Rule 2012]

[Devices subject to this condition: D1, D2, D14, D21]

82-3. The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

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

The CEMS shall be installed and operated, 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.

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

The CEMS shall be installed and operating no later than 90 days after initial startup of the boiler.

[Rule 1303 – BACT, Rule 1303 – Offset, Rule 218]

[Devices subject to this condition: D3]

82-4. The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration is expressed in ppmv.

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 12 months after initial start-up of the boiler 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 boiler startup date, the operator shall provide written notification to the District of the exact date of start-up.

[Rule 2012]

[Devices subject to this condition: D3]

99-1. The 2.0 PPM NOx emission limit(s) shall not apply during turbine commissioning, startup, and shutdown periods. Startup time shall not exceed 1 hour per startup and the number of startups shall not exceed one per day. Shutdown time shall not exceed 30 minutes per shutdown and the number of shutdowns shall not exceed one per day. The commissioning period shall not exceed 636 operating hours from the date of initial start-up. The operator shall provide the AQMD with written notification of the start-up date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from AQMD.

[Rule 2005 - BACT]

[Devices subject to this condition: D1, D2, D14, D21]

99-2. The 3.0 PPM CO emission limit(s) shall not apply during turbine commissioning, startup, and shutdown periods. Startup time shall not exceed 1 hour per startup and the number of startups shall not exceed one per day. Shutdown time shall not exceed 30 minutes per shutdown and the number of shutdowns shall not exceed one per day. The commissioning period shall not exceed 636 operating hours from the date of initial start-up. The operator shall provide the AQMD with written notification of the initial start-up date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from AQMD.

[Rule 1303 – BACT]

[Devices subject to this condition: D1, D2, D14, D21]

99-3. The 14.03 lbs/MMscf NOx emission limit(s) shall only apply during the interim period to report RECLAIM emissions. The interim period shall not exceed 12 months from the initial startup date.

[Rule 2012]

[Devices subject to this condition: D1, D2, D14, D21]

99-4. The 8.36 LBS/MMscf NOx emission limit(s) shall only apply during the interim reporting period to report RECLAIM emissions. The interim period shall not exceed 12 months from the initial startup date.

[Rule 2012]

[Devices subject to this condition: D3]

144-1. The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.

[Rule 1303- BACT]

[Devices subject to this condition: D7, D8]

157-1. The operator shall install and maintain a pressure relief valve set at 25 psig.

[Rule 1303- BACT]

[Devices subject to this condition: D7, D8]

179-1. 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 based upon the average of the continuous monitoring for that hour.

Condition no. 12-1
Condition no. 12-2

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: C4, C5, C6]

179-2. For the purpose of the following condition number(s) continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that month.

Condition no. 12-3

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: C4, C5, C6]

193-1. The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the Final Energy Commission Decision for 01-AFC-17 project.

[CEQA]

[Devices subject to this condition: D1, D2, D3, D7, D8, D9, D10, D14, D21]

195-1. The 2.0 ppmv NOx emissions limit is averaged over 1-hour, dry basis at 15% O2. The limit shall not apply to the first fifteen 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O2, in any rolling 12-month period for each combustion gas turbine provided that it meets all of the following requirements:

A. This equipment operates under any one of the qualified conditions described below:
   a) Rapid combustion turbine load changes due to the following conditions:
      - Load changes initiated by the California ISO or a successor entity when the plant is operating under Automatic Generation Control; or
      - Activation of a plant automatic safety or equipment protection system which rapidly decreases turbine load
   b) The first two1-hour reporting periods following the initiation/shutdown of a fogging system injection pump
   c) The first two1-hour reporting periods following the initiation/shutdown of combustion turbine steam injection
   d) The first two1-hour reporting periods following the initiation of HRSG duct burners
   e) Events as the result of technological limitation identified by the operator and approved in writing by the AQMD Executive Officer or his designees
B. The 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O2, did not occur as a result of operator neglect, improper operation or maintenance, or qualified breakdown under Rule 2004(i).
C. The qualified operating conditions described in (A) above are recorded in the plant's operating log within 24 hours of the event, and in the CEMS by 5 p.m. the next business day following the qualified operating condition. The notations in the log and CEMS must describe the data and time of entry into the log/CEMS and the plant operating conditions responsible for NOx emissions exceeding the 2.0 ppmv 1-hour average limit.
D. The 1-hour average NOx concentration for periods that result from a qualified operating condition does not exceed 25 ppmv, dry basis at 15 percent O2

All NOx emissions during these events shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

[Rule 2005 - BACT]

[Devices subject to this condition: D1, D2, D14, D21]

195-2. The 3.0 ppmv CO emission limit is averaged over 1 hour, dry basis at 15 percent oxygen when the HRSG duct burners are not operating. The 4.0 ppmv CO emission limit is averaged over 1 hour, dry basis at 15% o2 when the HRSG duct burners are operating.

[Rule 1303 – BACT]

[Devices subject to this condition: D1, D2, D14, D21]

195-3. The 2.0 PPMV ROG emission limit(s) are averaged over 1 hour at 15 percent oxygen, dry basis.

[Rule 1303 – BACT]

[Devices subject to this condition: D1, D2, D14, D21]

195-4. The 7 PPMV NOx emission limit(s) are averaged over 1 hour at 3 percent oxygen, dry basis.

[Rule 2005 - BACT]

[Devices subject to this condition: D3]

195-5. The 50 PPMV CO emission limit(s) are averaged over 1 hour at 3 percent oxygen, dry basis.

[Rule 1303 – BACT]

[Devices subject to this condition: D3]

195-6. The 5 PPMV NH3 emissions limit(s) are averaged over 1 hour at 15 percent oxygen, dry basis.

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: C4, C5]

195-7. The 5 PPMV NH3 emissions limit(s) are averaged over 1 hour at 3 percent oxygen, dry basis.

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: C6]

232-1. The operator shall install, operate, and maintain an approved Continuous Emission Monitoring Device, approved by the Executive Officer, to monitor and record ammonia concentrations, and alert the operator (via audible or visible alarm) whenever ammonia concentrations are near, at, or in excess of the permitted ammonia limit of 5 ppmv, corrected to 15% oxygen. It shall continuously monitor, compute, and record the following parameters:

Ammonia concentration, uncorrected in ppmv

Oxygen concentration in percent

Ammonia concentration in ppmv, corrected to 15% oxygen

Date, time, extent (in time) of all excursions above 5 ppmv, corrected to 15% oxygen

The Continuous Emission Monitoring Device described above shall be operated and maintained according to a Quality Assurance Plan (QAP) approved by the AQMD Executive Officer. The QAP must address contingencies for monitored ammonia concentrations near, at, or above the permitted compliance limit, and remedial actions to reduce ammonia levels once a violation has occurred.

The Continuous Emission Monitoring Device may not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia.

The Continuous Emission Monitoring Device shall be installed and operating no later than 90 days after initial startup of the turbine.

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: C4, C5]

232-2. The operator shall install, operate, and maintain an approved Continuous Emission Monitoring Device, approved by the Executive Officer, to monitor and record ammonia concentrations, and alert the operator (via audible or visible alarm) whenever ammonia concentrations are near, at, or in excess of the permitted ammonia limit of 5 ppmv, corrected to 3% oxygen. It shall continuously monitor, compute, and record the following parameters:

Ammonia concentration, uncorrected in ppmv

Oxygen concentration in percent

Ammonia concentration in ppmv, corrected to 3% oxygen

Date, time, extent (in time) of all excursions above 5 ppmv, corrected to 3% oxygen

The Continuous Emission Monitoring Device described above shall be operated and maintained according to a Quality Assurance Plan (QAP) approved by the AQMD Executive Officer. The QAP must address contingencies for monitored ammonia concentrations near, at, or above the permitted compliance limit, and remedial actions to reduce ammonia levels once a violation has occurred.

The Continuous Emission Monitoring Device may not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia.

The Continuous Emission Monitoring Device shall be installed and operating no later than 90 days after initial startup of the boiler.

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: C6]

296-1. This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year 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 first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

[Rule 2005 – Offsets]

[Devices subject to this condition: D1, D2, D3, D9, D10, D14, D21]

327-1. 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]

[Devices subject to this condition: D1, D2, D14, D21]

APPENDIX A EMISSIONS – GAS TURBINE

EMISSION LIMITS

Criteria pollutant emissions are calculated using manufacturer provided data and applicable BACT emission factors. The emission limits of the gas turbine including the duct burners and SCR system, as proposed by the applicant and accepted by the District per BACT/LAER determinations are the following:

CO = 3 ppmv without duct burners firing and 4 ppmv with duct burners firing, 1-hour rolling average, dry at 15% O_2; 2 ppmv, annual average
NOx = 2.0 ppmv, 1-hour average; 2.0 ppmv, annual average
ROG = 2 ppmv, 1-hour average (with duct burner firing), 1.4 ppmv, 1-hour average, actual stack O_2 level (without duct burner firing)
SOx = 0.25 gr/100 scf, sulfur content of natural gas
PM10 = 9.0 lb/hr without duct burners firing, and 10.5 lb/hr with duct burners firing, which are equivalent to 0.0054 and 0.0042 lb/MMBtu respectively. They are more stringent than the level of 0.0066 lb/MMBtu particulate matter level specified in AP-42.

Emission factors during the startup and shutdown are much higher. The application provided several sets of emission factors, i.e., one set for modeling and another for averaged emissions calculation. The following set of data is provided in Table K.3-9 of the application for calculation of 30-day averaged emissions during the startup process:

CO = 100 lb/hr. NOx = 80 lb/hr
ROG = 16 lb/hr, SOx = 1.78 lb/hr
PM10 = 9.0 lb/hr

Emission factors of the shutdown process are lower than the startups. However, the application has elected to use the same factors of the startups for shutdowns.

FUEL CONCENTRATION AND EXPANSION FACTOR

Table 5.2-15 of the application provides a gas analysis of the natural gas to be used for the facility, which is shown in Table A-1. The natural gas is found to consist of methane, several paraffin, carbon dioxide, and nitrogen. The generalized chemical reaction of paraffin combustion in atmosphere is:

$$C_nH_{2n+2} + (1.5n + 0.5)(O_2 + 3.76N_2) = nCO_2 + (n+1)H_2O + 3.76(1.5n + 0.5)N_2$$

The expansion factor, which is defined as the ratio of dry exhaust flow over the fuel flow, is:

$$\textit{Expansion Factor} = 3.76(1.5n + 0.5) + n$$

As an example, the expansion factor is 21.8 for propane (C_3H_8, n=3). A weighted expansion factor for the natural gas can be calculated based on the gas composition and the individual expansion factors. The results are given in Table A-1. A similar analysis can be found in Perry's Chemical Engineer's Handbook, 6th Edition, Chapter 9.

For emission calculations that require exhaust corrected to 15% O_2 level, a correction factor of 20.9/(20.9-15) or 3.542 shall be used in conjunction with the expansion factor. Similarly, a correction factor of 20.9/(20.9-3) or 1.676 shall be used for emission calculations that require exhaust correct to 3% O_2 level.

Table A-1 Natural Gas Composition

Composition	MW	Fraction %	Expansion Factor	Comb. EF
CO2	44	1.07%	1	0.01
N2	28	0.84%	1	0.01
CH4	16	96.01%	8.52	8.18
C2H6	30	1.69%	15.16	0.26
C3H8	44	0.24%	21.8	0.05
C4H10	58	0.08%	28.44	0.02
C5H12	72	0.03%	35.08	0.01
C6H14	86	0.04%	41.72	0.02
			Average Expansion Factor =	**8.56**

EMISSIONS DURING NORMAL OPERATIONS

EQUATIONS

For NOx, CO and ROG, emissions are calculated with the following formulas.

Volumetric emission rate = ppmv concentration * exhaust flow rate at 15% O_2 level
= ppmv concentration * stoichiometric exhaust flow rate * correction factor
= ppmv concentration * fuel flow rate * expansion factor * correction factor

Mass Emission Rate = volumetric emission rate * density at standard conditions
= volumetric emission rate * molecular weight / standard specific volume

For SOx, since there is no emission concentration level, the following formula should be used:

Mass emission rate = fuel sulfur mass concentration * fuel usage * 64/32

where the ratio of 64/32 reflects the molecular weight (MW) ratio between SO_2 and sulfur. To convert the fuel sulfur level to concentration:

Fuel sulfur ppmv level = sulfur concentration * standard gas specific volume / MW
Exhaust SOx ppmv level = Fuel sulfur ppmv level /expansion factor / correction factor

For example, a fuel sulfur concentration of 1 grain per 100 scf is equivalent to volumetric concentration of 17 ppmv. This concentration is equivalent to 0.57 ppmv in the exhaust.

For PM10, the application provided mass emission rates of 9 lb/hr at base load and 11 lb/hr at peak load (duct burners firing). These rates will be used to determine compliance with Rule 475. By using the formula below the mass emission rate can be converted to volumetric concentration.

Volumetric exhaust PM10 concentration = mass concentration (lb/hr) /exhaust flow rate (MMscf/hr)

Based on the gas turbine exhaust flow rate, the mass emission rate of 11 lb/hr is equivalent to the volumetric emission rate of less than 0.01 grain/dscf. Therefore, the proposed emission rates would comply with Rule 475.

Several important constants and conversion factors are:

P = 14.7 PSIA, T = 293 K at the standard conditions
1 lb-mole ideal gas = 385 scf at the standard conditions (standard specific volume)

<u>RESULTS</u>

Emissions under four operation scenarios are calculated and shown in the next four tables. The first two tables show emissions calculated by using the 1-hour emission limits, with and without duct burners firing. The last two tables show emissions calculated by using the annual operation emission limits, with and without duct burners firing. Results from the last two tables are used in Reg. XIII and Rule 2005 to determine offset obligations for criteria emissions.

Based on GE provided data, ROG emissions are limited to 1.4 ppmv when the duct burners are not firing, at actual stack O_2 level. Oxygen level in the exhaust is about 13.5% under normal operating conditions. Therefore, the ROG level at 15% O2 is 1.1 ppmv based on the following:

$$1.4 * \frac{20.9 - 15}{20.9 - 13.5} = 1.1 \text{ ppmv at } 15\% \text{ O2}$$

Table A-2 One Turbine without DB, 36 °F, 100% Load, 1-hour Average

Variables	Unit	NOx*	CO*	ROG*	SOx	PM10
Heat Input	MMBtu/hr	1,813	1,813	1,813	1,813	1,813
Heating Value	Btu/scf	1,010	1,010	1,010	1,010	1,010
Fuel Usage	MMscf/hr	1.795	1.795	1.795	1.795	1.795
Expansion Factor		8.56	8.56	8.56	8.56	8.56
Correction Factor (15% O2)		3.54	3.54	3.54	3.54	3.54
Molecular Weight (MW)	lb/lb-mole	46	28	16	64	/
Sulfur Concentration in Fuel	GR/scf	/	/	/	0.0025	/
Sulfur Concentration in Fuel	ppmv	/	/	/	4.30	/
Uncontrolled Concentration	ppmv	25				/
Controlled Concentration	ppmv	2.0	3.0	1.1	0.14	/
PM10 emission factor	lb/MMBtu					0.0050
Volumetric Emission Rate	scf/hr	108.9	163.3	59.9	7.7	
Controlled Emission Rate	lb/hr	**13.01**	**11.88**	**2.49**	**1.28**	**9.00**
NOx Emission Rate, No SCR	lb/hr	162.6				
NOx Emission Rate, No SCR	lb/MMBtu	0.09				
Controlled Emission Rate	lb/MMBtu	0.007	0.007	0.0014	0.001	0.0050
Controlled Emission Factor	lb/MMscf	**7.25**	**6.62**	**1.39**	**0.71**	**5.01**

* NOx at 2.0 ppmv, CO at 4.0 ppmv, and ROG at 1.1 ppmv corrected to 15% O_2, dry basis.

Table A-3 One Turbine with DB, 36 °F, 100% Load, 1-hour Average

Variable	Unit	NOx*	CO*	ROG*	SOx	PM10
Heat Input	MMBtu/hr	2510	2510	2510	2510	2510
Heating Value	Btu/scf	1010	1010	1010	1010	1010
Fuel Usage	MMscf/hr	2.485	2.485	2.485	2.485	2.485
Expansion Factor		8.56	8.56	8.56	8.56	8.56
Correction Factor (15% O2)		3.54	3.54	3.54	3.54	3.54
Molecular Weight	lb/lb-mole	46	28	16	64	
Sulfur Concentration in Fuel	GR/scf	/	/	/	0.0025	/
Sulfur Concentration in Fuel	ppmv	/	/	/	4.30	/
Uncontrolled Concentration	ppmv	25.0				
Controlled Concentration	ppmv	2.0	4.0	2.0	0.14	/
PM10 Emission Factor	lb/MMBtu					0.0064
Volumetric Emission Rate	scf/hr	150.7	301.2	150.7	10.7	/
Controlled Emission Rate	lb/hr	**18.01**	**21.92**	**6.26**	**1.78**	**10.50**
NOx Emission Rate, No SCR	lb/hr	225.1				
NOx Emission Rate, No SCR	lb/MMBtu	0.09				
Controlled Emission Rate	lb/MMBtu	0.007	0.0087	0.0025	0.001	0.0042
Controlled Emission Factor	lb/MMscf	**7.25**	**8.82**	**2.52**	**0.71**	**4.23**

* NOx at 2.5 ppmv, CO at 4.0 ppmv, and ROG at 2 ppmv corrected to 15% O_2, dry basis

Table A-4 One Turbine without DB, 36 °F, 100% Load, Annual Average

Variable	Unit	NOx*	CO*	ROG*	SOx	PM10
Heat Input	MMBtu/hr	1813	1813	1813	1813	1813
Heating Value	Btu/scf	1010	1010	1010	1010	1010
Fuel Usage	MMscf/hr	1.795	1.795	1.795	1.795	1.795
Expansion Factor		8.56	8.56	8.56	8.56	8.56
Correction Factor (15% O2)		3.54	3.54	3.54	3.54	3.54
Molecular Weight	lb/lb-mole	46	28	16	64	/
Sulfur Concentration in Fuel	GR/scf	/	/	/	0.0025	/
Sulfur Concentration in Fuel	ppmv	/	/	/	4.30	/
Uncontrolled Concentration*	ppmv	25				/
Controlled Concentration*	ppmv	2	2	1.10	0.14	/
PM10 Emission Factor	lb/MMBtu					0.0050
Volumetric Emission Rate	scf/hr	108.9	108.9	59.9	7.7	/
Hourly Mass Emission Rate	lb/hr	**13.01**	**7.92**	**2.49**	**1.28**	**9.0**
Emission Rate	lb/MMBtu	0.0072	0.0044	0.0014	0.001	0.0050
Emission Factor	lb/MMscf	**7.25**	**4.41**	**1.39**	**0.71**	**5.01**

* NOx at 2 ppmv, CO at 2 ppmv, and ROG at 1.1 ppmv corrected to 15% O_2, dry basis

Table A-5 One Turbine with DB, 36 °F, 100% Load, Long-Term Average

Variable	Unit	NOx*	CO*	ROG*	SOx	PM10
Heat Input	MMBtu/hr	2510	2510	2510	2510	2510
Heating Value	Btu/scf	1010	1010	1010	1010	1010
Fuel Usage	MMscf/hr	2.485	2.485	2.485	2.485	2.485
Expansion Factor		8.56	8.56	8.56	8.56	8.56
Correction Factor (15% O2)		3.54	3.54	3.54	3.54	3.54
Molecular Weight	lb/lb-mole	46	28	16	64	
Sulfur Concentration in Fuel	GR/scf	/	/	/	0.0025	/
Sulfur Concentration in Fuel	ppmv				4.30	
Uncontrolled Concentration*	ppmv	25				
Controlled Concentration*	ppmv	2	2	2	0.14	/
PM10 Emission Rate	lb/MMBtu					0.0042
Volumetric Emission Rate	scf/hr	150.7	150.7	150.7	10.7	/
Hourly Mass Emission Rate	lb/hr	**18.01**	**10.96**	**6.26**	**1.78**	**10.50**
Emission Rate	lb/MMBtu	0.007	0.004	0.002	0.001	0.0042
Emission Factor	lb/MMscf	**7.25**	**4.41**	**2.52**	**0.71**	**4.23**

* NOx at 2 ppmv, CO at 2 ppmv, and ROG at 2 ppmv corrected to 15% O_2, dry basis

EMISSION DURING COMMISSIONING PERIOD AND INTERIM PERIOD

PROCESS DESCRIPTION – COMMISSIONING PERIOD

The commissioning period is when the facility follows a strict step-by-step schedule to fine-tune the gas turbine's combustion and turbomachinery systems. Only after the gas turbine system is successfully commissioned it may reach the optimal performance (design point). Normally the commissioning schedule is recommended by the manufacturer and may take 1-2 months. Emissions during this period are typically high, and they need to be calculated separately. The following is the proposed commissioning schedule:

- Full Speed No Load Tests (FSNL)

These tests will occur over approximately 3-day per turbine/HRSG. Heat input to the turbine will be around 20% of full load during the test. There will be no SCR or CO catalyst installed, and the DLN burners may not be fully optimized. NOx emissions can be as high as 100 ppmv during these tests, and CO emissions may be as high as 385 lbs per hour.

- Part Load Test

These tests will occur over a 6-day period per gas turbine, with turbine load at about 60% of full load. During the period the DLN burners will be tuned to minimize emissions and the HRSG/steam turbine line checks will be performed. There will be no SCR or CO catalyst control, and NOx emissions may be as high as 100 ppmv during these tests, and CO emissions up to 385 lbs/hr.

- Full Load Test (SCR not operational)

These tests will occur over a 2-day period per gas turbine with the turbine at 100% load. During this period there will be further checks on the HRSG and steam lines. Even though there will not be SCR control, the emissions are expected to be low since the combustors are now fully optimized. NOx concentrations are to be in the range of 25 ppmv. The CO catalyst will be installed and operational, and CO emissions are expected to be at 4 ppmv.

- Full Load Tests (SCR partial operation)

These tests will occur at 100% turbine load over a 1-day period per gas turbine. The goal is to optimize the SCR system. Tests will include checking the ammonia injection grid. NOx emissions can be expected to be 25 ppmv or less, with CO emissions at 4 ppmv since the CO catalyst will be functional.

- Full Load Tests (SCR Operational)

These tests will occur over an 11-day period for the first turbine and a 1-day period for the second turbine. The tests will be run at full turbine load, SCR operational, and the NOx concentrations should be at or near the levels expected during normal operation, with CO emissions again at 4 ppmv.

During the commissioning period the application assumes there are 6 additional hours hot startup time for each gas turbine. The commissioning period is 23 working days for turbine #1, and 13 days for turbine #2.

PROCESS DESCRIPTION – INTERIM PERIOD

The interim period is a RECLAIM terminology that is defined as a period, typically up to 12 months, when the NOx CEMS has not been certified. During this period the emissions could not be accurately monitored and verified. Therefore, the NOx emissions are assumed to be at the uncontrolled levels, i.e., the SCR not functional or operation undeterminable. As so, the NOx concentration will be assumed to be at 25 ppmv, corrected to 15% oxygen.

ASSUMPTIONS

Table A-6 contains the emission factors and assumptions provided in the application for the commissioning period.

Table A-6 Commissioning Schedule Emission Factors

Process	NOx	CO	ROG	PM10	SOx
No Load	125 lb/hr(1)	180 lb/hr(1)	17 lb/hr(1)	9 lb/hr	0.25 gr/100 scf
60% Load	33 ppmv (1)	385 lb/hr(1)	16 lb/hr	9 lb/hr	0.25 gr/100 scf
100% Load, No SCR	25 ppmv (2)	10 ppmv(2)	1.4 ppmv(4)	9 lb/hr	0.25 gr/100 scf
100% Load, Partial SCR	14 ppmv (3), 25 ppmv (6)	4 ppmv	1.4 ppmv(4)	9 lb/hr	0.25 gr/100 scf
100% Load, Full SCR	2.0 ppmv(1), 25 ppmv (6)	4 ppmv	1.4 ppmv(4)	9 lb/hr	0.25 gr/100 scf
Hot Startups(5)	80 lb/hr	838 lb/hr	16 lb/hr	9 lb/hr	1.77 lb/hr

1) Based on data of a GE F7A machine, provided by the applicant
2) Based on GE F7B performance data, provided by the applicant
3) Based on the mid-point between 25 ppmv and 2.5 ppmv.
4) Based on GE F7B performance data at actual exhaust oxygen level.
5) Startup emission levels are provided by the applicant
6) During the commissioning period the SCR operation could not be verified since the CEMS is not certified. NOx concentration is assumed to be 25 ppmv, rather than 2.0 ppmv controlled level.

Table A-7 shows the timetable of the commissioning period and the corresponding emission factors. For all hours of full load the NOx emissions limit is assumed as 25 ppmv and the emission rate as 0.09 lb/MMBtu.

Table A-7 Emission Factors of the Commissioning Period

Operating Mode	Time (hr)	Load %	Heat Input (MMBtu/hr)	Emission Factors (lb/MMBtu) NOx	CO	ROG	PM10	SOx
CTG 1 – FSNL	72	20%	355	0.352	0.507	0.0479	0.0254	0.0007
CTG 2 – FSNL	72	20%	355	0.352	0.507	0.0479	0.0254	0.0007
CTG 1 – Partial Load	144	60%	1,302	0.119	0.296	0.0123	0.0069	0.0007
CTG 2 – Partial Load	144	60%	1,302	0.119	0.296	0.0123	0.0069	0.0007
CTG 1– Full Load, No SCR	48	100%	1,813	0.09	0.017	0.0015	0.0050	0.0007
CTG 2– Full Load, No SCR	48	100%	1,813	0.09	0.017	0.0015	0.0050	0.0007
CTG 1–Full Load, Partial SCR	24	100%	1,813	0.09	0.009	0.0015	0.0050	0.0007
CTG 2–Full Load, Partial SCR	24	100%	1,813	0.09	0.009	0.0015	0.0050	0.0007
CTG 1– Full Load, Full SCR	264	100%	1,813	0.09	0.009	0.0015	0.0050	0.0007
CTG 2– Full Load, Full SCR	24	100%	1,813	0.09	0.009	0.0015	0.0050	0.0007
CTG 1– Hot Starts	6	60%	1,302					
CTG 2– Hot Starts	6	60%	1,302					
Total hours of commissioning	876							

Total hours of commissioning (both turbines): 876 hours

Table A-8 converts the emissions data of Table A-7 into hourly emissions rates.

Table A-8 Hourly Emission Rates of Commissioning Period

Operating Mode	Hourly Emissions (lbs/hr) NOx	CO	ROG	PM10	SOx
CTG/HRSG 1 – FSNL	125	180	17.0	9.00	0.25
CTG/HRSG 2 – FSNL	125	180	17.0	9.00	0.25
CTG/HRSG 1 – Partial Load	155	385	16.0	9.00	0.91
CTG/HRSG 2 – Partial Load	155	385	16.0	9.00	0.91
CTG/HRSG 1 – Full Load, No SCR	163	32	2.7	9.00	1.27
CTG/HRSG 2 – Full Load, No SCR	163	32	2.7	9.00	1.27
CTG/HRSG 1 – Full Load, Partial SCR	163	16	2.7	9.00	1.27
CTG/HRSG 2 – Full Load, Partial SCR	163	16	2.7	9.00	1.27
CTG/HRSG 1 – Full Load, Full SCR	163	16	2.7	9.00	1.27
CTG/HRSG 2 – Full Load, Full SCR	163	16	2.7	9.00	1.27
CTG/HRSG 1 – Hot Starts	80	838	16.0	9.00	1.77
CTG/HRSG 2 – Hot Starts	80	838	16.0	9.00	1.77

Table A-9 shows the emissions during each step of the turbine commissioning period.

Table A-9 Emissions during the Commissioning Period

Operating Mode	Total Emissions (lbs)				
	NOx	CO	ROG	PM10	SOx
CTG/HRSG 1 – FSNL	9,000	12,959	1,224	648	18
CTG/HRSG 2 – FSNL	9,000	12,959	1,224	648	18
CTG/HRSG 1 – Partial Load	22,274	55,440	2,306	1,296	131
CTG/HRSG 2 – Partial Load	22,274	55,440	2,306	1,296	131
CTG/HRSG 1 – Full Load, No SCR	7,832	1,514	131	432	61
CTG/HRSG 2 – Full Load, No SCR	7,832	1,514	131	432	61
CTG/HRSG 1 – Full Load, Partial SCR	3,916	392	65	216	30
CTG/HRSG 2 – Full Load, Partial SCR	3,916	392	65	216	30
CTG/HRSG 1 – Full Load, Full SCR	43,077	4,308	718	2,376	335
CTG/HRSG 2 – Full Load, Full SCR	3,916	392	65	216	30
CTG/HRSG 1 – Hot Starts	480	5,028	96	54	10.62
CTG/HRSG 2 – Hot Starts	480	5,028	96	54	10.62
Total Emissions (Two Turbines)	**133,997**	**155,366**	**8,427**	**7,884**	**866**

Based on the data shown in Table A-9, the next table shows a breakdown of emissions from each turbine during the commissioning period.

Table A-10 Emissions of Each Turbine during Commissioning Period

	NOx	CO	ROG	PM10	SOx
Turbine 1	86,579	79,641	4,540	5,022	586
Turbine 2	47,148	75,725	3,887	2,862	281

Turbine 1 NOx emissions during its commissioning period: 86,579 lbs
Turbine 2 NOx emissions during its commissioning period: 47,148 lbs

EMISSION FACTOR – COMMISSIONING PERIOD

Emission factors of the commissioning period are calculated for the purposes of reporting emissions in the absence of a certified CEMS. The NOx emission factor must be used for the RECLAIM emissions report. To determine the average NOx emission factor during the commissioning period the following formula are used:

Average Emission Factor = Total Emissions / Total Fuel Consumption

Fuel Consumption = Fuel Consumption at 100% load * Total equivalent 100% load hours

Total equivalent 100% load hours = 2*72*20% + 2*144* 72%+ 2*48 + 2*24 + 264 +24 + 6*2*72% = 676.8 hours

Fuel Consumption = 1.795 MMscf/hr * 676.8 hours = 1,214.86 MMscf, both turbines.

Table A-11 Average Emission Factors during Commissioning Period, Both Turbines

Emissions	NOx	CO	ROG	PM10	SOx
Total Emissions (lbs)	133,997	155,366	8,427	7,884	866
Total Hours (hr)	876	876	876	876	876
Total Fuel (MMscf)	1,215	1,215	1,215	1,215	1,215
Emission Factors (lb/MMscf)	110.29	127.87	6.94	6.49	0.71

Thus, the average NOx emission factor during the commissioning period shall be 110.29 lb/hr per turbine. The CO emission factor is 127.87 lb/MMscf for one turbine. The CO emission factor will be used in Condition 63-1.

EMISSION FACTOR – INTERIM REPORTING PERIOD

RECLAIM requires a single NOx emissions factor to be used for reporting emissions during the interim report period. As discussed before, the interim report period can be broken into the first month which includes the commissioning period, and the rest 11 months of normal operation assuming uncontrolled emissions.

First Month Emissions

Average daily emissions during one calendar month constitute the potential to emit. Average emissions during the month that includes the commissioning period are calculated and compared with the emissions of a month during normal operations. If the commissioning period emissions were higher, they would become the potential to emit (PTE) for the purposes of determining emission offsets. Since the commissioning period for each turbine is less than 30 days, the rest days of the calendar month is assumed to be normal operation.

One calendar month is defined as 31 days and has 744 hours.

Turbine 1: Total commissioning hours: 558
Regular operating hours: 186

Turbine 2: Total commissioning hours: 318
Regular operating hours: 426

Monthly fuel consumption of one turbine is calculated as:

Fuel Consumption = 744 hr/month * 1.795 MMscf/hr = 1335.5 MMscf/month

The next table shows the first month emissions of gas turbine No. 1, including the scenario when the facility is able to certify the NOx CEMS right after it completes the commissioning period.

Table A-12 First Month Emissions, Turbine #1

Pollutants	Commission Emissions (lbs)	Normal Op. Emissions (lbs)	Combined Emissions (lbs)	Fuel Consumption (MMscf)	30-day Average (lb/day)	Avg. Emi. Factor (lb/MMscf)
NOx(1)	86,579	2,420(1)	88,999	1,335.5	2,967	66.64
NOx	86,579	30,350(2)	116,929	1,335.5	3,898	87.55
CO	79,641	2,976(3)	82,617	1,335.5	2,754	61.86
ROG	4,540	506(4)	5,046	1,335.5	168	3.78
PM10	5,022	1,674(5)	6,696	1,335.5	223	5.01
SOx	586	236(6)	822	1,335.5	27	0.62

(1) If the facility is able to certify the NOx CEMS immediately after the commissioning process is completed. Assume 2.0 ppmv NOx emission limit and 186 hours.
(2) based on 186 hours and emission rate of 163 lb/hr as shown in Table A-8
(3) based on 186 hours and emission rate of 16 lb/hr as shown in Table A-8
(4) based on 186 hours and emission rate of 2.72 lb/hr as shown in Table A-8
(5) based on 186 hours and emission rate of 9 lb/hr as shown in Table A-8
(6) based on 186 hours and emission rate of 1.27 lb/hr as shown in Table A-8

Notice that the 30-day average emissions are the same for both turbines. The only difference in their commissioning schedule is the full load test duration, which is equivalent to normal operation. In a calendar month, however, the combined hours of normal operation and full load test are the same for both turbines.

Emissions of the Next Eleven Months

Emissions during the next 11 months are calculated based on a daily operating schedule of 1 hour hot startup, 7 hours operation without the duct burners, and 16 hours with the duct burners. During this period, since the NOx CEMS has not been certified, the SCR is considered as non-operational and the NOx emissions are considered at the uncontrolled level, i.e., 25 ppmv. The uncontrolled NOx emission rate is 0.09 lb/MMBtu according to the calculations shown in the Table A-2 and A-3. The 25 ppmv NOx emission level corresponds to the emission rate of 162.6 lbs/hr without the duct burners firing, and 225.1 lbs/day with the duct burners firing. Results are shown in Table A-13. The emissions from the possible scenario when the facility is able to certify the NOx CEMS at the conclusion of the commissioning process are also calculated. NOx emissions are then calculated by assuming a concentration of 2.0 ppmv and emission rate of 0.007 lb/MMBtu. Results are shown in Table A-14.

Table A-13 NOx Emissions of One Turbine during the next 11 Months, CEMS not Certified

Operation	Daily Hours	Total Hours (11 month)	Fuel Rate (MMscf/hr)	Emission Rate (lb/hr)	Fuel (MMscf)	Emissions (lbs)
Startup	1	335	1.29	80	432.2	26,800
Operating w/o DB	7	2,345	1.795	162.6(1)	4,209.3	381,297
Operating w/ DB	16	5,360	2.485	225.1(1)	13,319.6	1,206,536
Total					**17,961.1**	**1,614,633**

(1) Based on uncontrolled emission rate of 0.09 lb/MMscf, see Table A-2 and Table A-3.

The next table shows NOx emissions from one gas turbine if the NOx CEMS is certified at the conclusion of the commissioning period.

Table A-14 NOx Emissions of One Turbine during the next 11 Months, CEMS Certified

Operation	Daily Hours	Total Hours (11 month)	Fuel Rate (MMscf/hr)	Emission Rate (lb/hr)	Fuel (MMscf)	Emissions (lbs)
Startup	1	335	1.29	80	432.2	26,800
Operating w/o DB Firing	7	2,345	1.795	13.01(1)	4,209.3	30,508
Operating w/ DB Firing	16	5,360	2.485	18.01(1)	13,319.6	96,534
Total					**17,961.1**	**153,842**

(2) Based on controlled emission rate of 0.007 lb/MMscf, see Table A-4 and Table A-5.

Unlike the SCR that relies on CEMS data to achieve optimum NOx control, the CO catalyst is independent of the CO CEMS data. Thus, the CO emissions can be assumed to be at the similar levels of normal operation, i.e., the controlled emission rates of 7.92 lb/hr without the duct burners and 10.96 lb/hr with the duct burners firing as shown in Table A-4 and A-5. The next table shows the monthly CO emissions during the next 11 months of the interim period.

Table A-15 CO Emissions of One Turbine during 11 Months of Interim Period

Operation	Daily Hours	Total Hours (11 month)	Fuel Rate (MMscf/hr)	Emission Rate (lb/hr)	Fuel (MMscf)	Emissions (lbs)
Startup	1	335	1.29	838	432.2	280,730
Operating w/o DB Firing	7	2,345	1.795	7.92(1)	4,209.3	18,572
Operating w/ DB Firing	16	5,360	2.485	10.96(1)	13,319.6	58,746
Total					**17,961.1**	**358,048**

(1) Based on controlled emission rates, see Table A-4 and A-5.

Emission factors during this period are then:

NOx: 153,842/17,961.1 = 8.57 lb/MMscf, if the CEMS is certified after commissioning
NOx: 1,614,633/17,961.1= 89.90 lb/MMscf
CO: 358,048/17,961.1= 19.93 lb/MMscf

The NOx emission factor of 89.90 lb/MMscf shall apply after the first month (including the commissioning period) if the facility has not certified the NOx CEMS. Otherwise, the NOx emission factor of 8.57 lb/MMscf shall apply. The CO emission factor of 19.93 lb/hr shall apply after the first month.

Emissions of the Interim Reporting Period

Interim reporting period includes the first 12 months of operation. Table A-16 determines the NOx emission factor of the interim reporting period by combining the results of Table A-12 and Table A-14,

Table A-16 NOx Emission Factor during the Interim Period, CEMS not Certified

Period	Fuel Usage (MMscf)	NOx Emissions (lb)	Emission Factor (lb/MMscf)
First Month	1,335.5	116,929	87.55
Rest 11 Months	17,961.1	153,842	8.57
Interim Period Total	19,296.6	270,771	**14.03**

This emission factor of 14.03lb/hr shall apply during the interim reporting period before the facility has certified the NOx CEMS.

If the facility is able to certify the NOx CEMS immediately after the commissioning period, the interim reporting period is then equivalent to the commissioning period. In this event, the NOx emission factor of 110.29 lb/MMscf (Table A-11) applies to the commissioning period.

APPENDIX B EMISSIONS - AUXILIARY EQUIPMENT

EMISSIONS FROM THE AUXILIARY BOILER

The following table compares the applicant proposed BACT limits with the current AQMD determined BACT limits. The most stringent limits will be used for BACT.

Table B-1 BACT Requirements for the Boiler

Emissions	BACT	Applicant Proposed	Most Stringent Level
NOx	7.0 ppmv at 3% O_2	9.0 ppmv at 3% O_2	7.0 ppmv at 3% O_2
CO	50 ppmv at 3% O_2	50 ppmv at 3% O_2	50 ppmv at 3% O_2
ROG	5.5 lb/MMscf(1), equivalent to 13.3 ppmv at 3% O_2	10 ppmv at 3% O_2	10 ppmv at 3% O_2
PM10	7.6 lb/MMscf(1)	Natural gas	7.6 lb/MMscf
SOx	Natural Gas	H_2S <0.25 gr/100 scf, equivalent SOx of 0.71 lb/MMscf	0.71 lb/MMscf
NH3	5 ppmv at 3% O_2	10 ppmv	5 ppmv

(1) AP-42 data, Table 1.4-2

Emissions are determined as shown in the following spreadsheet

Table B-2 Emissions Calculations – Auxiliary Boiler

Variable	Unit	CO	NOx	PM10	ROG	SOx	NH3
Heat-in	MMBtu/hr	129	129	129	129	129	129
Heating Value	Btu/scf	1,010	1,010	1,010	1,010	1,010	1,010
Fuel Usage	MMscf/hr	0.128	0.128	0.128	0.128	0.128	0.128
Expansion factor		8.56	8.56	8.56	8.56	8.56	8.56
Exhaust flow rate	MMscf/hr	1.093	1.093	1.093	1.093	1.093	1.093
Exhaust flow rate corrected to 3% O2	MMscf/hr	1.277	1.277	1.277	1.277	1.277	1.277
Molecular Weight	lb/lb-mole	28	46		16	64	17
Emission Factors	lb/MMscf			**7.6**		**0.71**	
Emission concentration	ppmv	**50**	7		**10**		**5**
Emission Rate	lb/hr	**4.64**	**1.07**	**0.97**	**0.53**	**0.09**	**0.28**
30-Day Average	lb/day	**111**	**26**	**23**	**13**	**2**	**7**
Monthly Maximum	lb/month	3,330	780	690	390	60	210
Emission Factor	lb/MMscf	36.25	8.36	7.58	4.14	0.7	2.19

For NOx, CO, ROG and NH3 use the next formula:

Emission = Emission Concentration * MW * Exhaust Flow rate (3% O2) * Gas Constant

For PM10 and SOx use the next formula:

Emission = Emission Factor * Fuel Flow rate

NOx emissions during the interim period, assuming the SCR is operating properly, is equivalent to normal operation. The NOx emissions factor is:

NOx = 8.36 lb/MMscf

EMISSIONS FROM THE EMERGENCY GENERATOR

The following table compares the applicant proposed BACT limits with the current AQMD determined BACT limits. The most stringent limits will be used for BACT.

Table B-3 BACT Requirements for the Emergency Generator

Pollutants	BACT(1)	Applicant Proposed	Most Stringent Level
CO	2.0 gram/BHP-hr	2.0 gram/BHP-hr	2.0 gram/BHP-hr
NOx	1.5 gram/BHP-hr	1.5 gram/BHP-hr	1.5 gram/BHP-hr
PM10	Natural gas	0.16 gram/BHP-hr	0.16 gram/BHP-hr
ROG	1.5 gram/BHP-hr	1.5 gram/BHP-hr	1.5 gram/BHP-hr
SOx	Natural gas	0.003 gram/BHP-hr	0.003 gram/BHP-hr

(1) District Guidelines

Emissions are determined as shown in the following spreadsheet. The 30-day averages are based on 200 hours operation per year.

Table B-4 Emissions – Emergency Generator

Emissions	Emi. Factor (gm/BHP-hr)	Power (BHP)	PTE (lb/hr)	PTE (lb/day)	30 Day Avg. (lb/day)	Annual Emissions (lb/year)
CO	2.0	1,467	6.47	155.2	4	1,294
NOx	1.5	1,467	4.85	116.4	3	970
PM10	0.16	1,467	0.52	12.4	0	103
ROG	1.5	1,467	4.85	116.4	3	970
SOx	0.003	1,467	0.01	0.2	0	2

The fuel consumption rate is 564 lb/hr, or 12, 750 scf/hr. The NOx emissions rate is then:

NOx = 4.85 lb/hr /12, 750 scf/hr = 0.38 X 10^{-3} lb/scf
NOx = 380 lb/MMscf

This emission factor will be used for RECLAIM NOx emissions report.

EMISSIONS FROM THE EMERGENCY FIRE PUMP ENGINE

Based on the applicant provided data and the District's BACT determination the following table is a summary of the emission limits.

Table B-5 BACT Requirements for the Emergency Fire Pump Engine

Pollutants	BACT(1)	Applicant Proposed	Most Stringent Level
CO	8.5 gram/BHP-hr	3.55 gram/BHP-hr	3.55 gram/BHP-hr
NOx	6.9 gram/BHP-hr	5.89 gram/BHP-hr	5.89 gram/BHP-hr
PM10	0.38 gram/BHP-hr	0.25 gram/BHP-hr	0.25 gram/BHP-hr
ROG	1.0 gram/BHP-hr	1.0 gram/BHP-hr	1.0 gram/BHP-hr
SOx	Fuel sulfur content < 0.05% by weight	0.17 gram/BHP-hr	0.17 gram/BHP-hr

(1) District Guidelines

Emissions are determined as shown in the following spreadsheet. The 30-day averages are based on 200 hours operation per year.

Table B-6 Emissions – Emergency Fire Pump Engine

Pollutants	Emi. Factor (gm/BHP-hr)	Power (BHP)	PTE (lb/hr)	PTE (lb/day)	30 Day Avg. (lb/day)	Annual Emissions (lb/)
CO	3.55	337	2.64	63.3	0	137
NOx	5.89	337	4.38	105.0	1	228
PM10	0.25	337	0.19	4.5	0	10
ROG	1	337	0.74	17.8	0	39
SOx	0.17	337	0.13	3.0	0	7

Given the fuel consumption rate of 18.3 gal/hr, the NOx emissions are:

NOx = 4.38 lb/hr /18.3 gal/hr = 0.24 lb/gal
NOx = 240 lb per 1, 000 gallons

This will be the default emission factor for the RECLAIM NOx emissions report.

APPENDIX C ERC AND RTC DETERMINATIONS

ERC AND POTENTIAL TO EMIT DETERMINATIONS

Emergency equipment are exempt from the modeling and offset requirements according to Rule 1304(a)(4). Therefore the facility ERC requirements will not include the emissions from the emergency generator and the emergency fire pump engine. The boiler and the gas turbines emissions, calculated in the previous sections, are used to determine the ERC requirements. For the gas turbines, the 30-day averaged emissions are based on the following operating schedule provided in the application.

Table C-1 Yearly and Monthly Operating Schedule

Year Operating Schedule		Monthly Operating Schedule	
Yearly hot start	365 hour	Monthly hot start	31 hours
Yearly with duct burner	5,100 hours	Monthly with duct burner	496 hours
Yearly without duct burner	3,295 hours	Monthly without duct burner	217 hours

Calculations in the next tables determine the amount of offset (ERC) the facility shall provide.

CO EMISSIONS

Table C-2 CO - Potential to Emit, Gas Turbines and Boiler

Operating Mode	Hours per Month	Emission Rate (lb/hr)	Emissions lb/month	30-day Average lb/day
Base load, w/o DB	217	7.92	1,719	57
Peak load, w/ DB	496	10.96	5,436	181
Startups	31	100	3,100	103
One Turbine Subtotal	744	14.24	10,255	342
Two Turbines Subtotal			20,510	684
Boiler	744	4.64	3,330	111
Total Emissions (lb)			23,840	795
ERC Required	(Offset Ratio 1.2)			***954***

Note: CO emission level of 2.0 ppmv on the applicant proposed annual average limit. Emission rate of 100 lb/hr during startup was provided by the applicant.

If the applicant elects to offset CO emissions from the priority reserve, the offset ratio is 1.0 and the amount of ERC shall be 795 lbs.

ROG EMISSIONS

ROG emissions rates of the gas turbines are taken from Table A-3 and A-4.

Table C-3 ROG, Potential to Emit, Gas Turbines and Boiler

Operating Mode	Hours per Month	Emission Rate (lb/hr)	Emissions lb/month	30-day Average lb/day
Base load, w/o DB	217	2.49	540	18
Peak load, w/ DB	496	6.26	3105	103
Startups	31	16	496	17
One Turbine Total	744	5.75	4,141	138
Two Turbines Total			8,282	276
Boiler	744	0.53	390	13
Total Emissions (lb)			8672	289
ERC Required	(Offset Ratio 1.2)			**347**

Note: ROG Emission rate of 16 lb/hr during startups was provided in the application.

PM10 EMISSIONS

ROG emissions rates of the gas turbines are taken from Table A-3 and A-4.

Table C-4 PM10, Potential to Emit, Gas Turbines and Boiler

Operating Mode	Hours per Month	Emission Rate (lb/hr)	Emissions lb/month	30-day Average lb/day
Base load, w/o DB	217	9.0	1,953	65
Peak load, w/ DB	496	10.5	5,208	174
Startups	31	9.0	279	9
One Turbine Total	744	10.3	7,440	248
Two Turbines Total			14,880	496
Boiler	744	0.97	690	23
Total Emissions (lb)			15,570	519
ERC Required	(Offset Ratio 1.2)			*623*

Note: Emission rate of the boiler is based on AP-42 published number of 0.0066lb/MMBtu.

If the applicant elects to obtain PM10 ERCs from the priority reserve, the offset ratio is 1.0 and the required PM10 ERC amount is 519 lbs. Otherwise, the amount of ERC required is 623 lbs.

SOX EMISSIONS

ROG emissions rates of the gas turbines are taken from Table A-3 and A-4.

Table C-5 SOx, Potential to Emit, Gas Turbines and Boiler

Operating Mode	Hours per Month	Emission Rate (lb/hr)	Emissions lb/month	30-day Average lb/day
Base load, w/o DB	217	1.28	278	9
Peak load, w/ DB	496	1.78	883	29
Startups	31	1.28	40	1
One Turbine Total	744	1.67	1,200	40
Two Turbines Total			2,400	80
Boiler	744	0.077	60	2
Total Emissions (lb)			2,460	82
ERC Required	(Offset Ratio 1.0, from priority reserve)			***82***

Note: emission rate of the boiler is based on AP-42 published number of 0.71 lb/MMscf.

NOX EMISSIONS

ROG emissions rates of the gas turbines are taken from Table A-3 and A-4.

Table C-6 NOx, Potential to Emit, Entire Facility

Operating Mode	Hours per Month	Emission Rate (lb/hr)	Emissions lb/month	30-day Average lb/day
Base load, w/o DB	217	13.01	2,823	94
Peak load, w/ DB	496	18.01	8,933	298
Startups	31	80.00	2,480	83
1 Turbine Total	744	19.13	14,236	475
2 Turbines Total			28,472	950
Boiler	744	1.067	780	26
Emergency Generator		4.85		3
Emergency Fire Pump Engine		4.38		1
Total Emissions (lb)				***980***

Since the facility has opted into the RECLAIM NOx program the NOx emissions will not be offset through the emission reduction credits (ERC). Daily emissions are for reference only.

GAS TURBINE EMISSIONS SUMMARY

The next table shows the monthly average emissions of the criteria pollutants. The data are excerpted from the previous five tables.

Table C-7 Criteria Pollutant Emissions Summary – One Turbine

Pollutants	Daily Emission (lb/day)	Monthly Emissions (lb/month)	Yearly Emissions (tons/year)
CO	342	10,255	61.5
NOx	475	14,236	85.4
PM10	248	7,440	44.6
ROG	138	4,141	24.8
SOx	40	1,200	7.2

NO_X RTC AND EMISSIONS CALCULATION

The facility will be in the NOx RECLAIM program. According to the rules of RECLAIM, NOx is offset by Reclaim Trading Credit (RTC) based on the first year of operation. First year operation is also the interim reporting period, i.e., the NOx CEMS is not certified. Therefore, the first year operation can be broken into the first month that includes the commissioning period and the next 11 months of operation without the NOx CEMS. The NOx emissions during the first year are determined in Appendix A, Table A-14.

NOx emissions, first month = 116, 929 lbs, one turbine
NOx emissions, next 11 months = 1,614,633 lbs, one turbine
NOx emissions, first year = 1,731,562 lbs, one turbine total
NOx emissions, first year = 3,463,124 lbs, two turbines total

If the facility elects to certify the NOx CEMS immediately after completion of the commissioning period, NOx emissions are calculated differently by assuming the control level. As determined in Table A-12 and Table A14

NOx emissions, first month = 89,614 lbs, one turbine
NOx emissions, next 11 months = 153,842 lbs, one turbine
NOx emissions, first year = 243,456 lbs, one turbine
NOx emissions, first year = 486,912 lbs, two turbines

The NOx emissions from the boiler, the emergency generator, and the emergency fire pump engine are included in the RTC calculations. The application indicates that the facility will operate the boiler for 3,000 hours in one year, the emergency generator for 200 hours in one year, and the emergency fire pump engine for 200 hours in one year. Therefore, the first year NOx emissions from these equipment are:

NOx, boiler = 3,000 hr * 1.067 lb/hr = 3, 201 lb
NOx, emergency generator = 52 hr * 4.85 lb/hr = 252 lb
NOx, emergency fire pump engine = 52 hr * 4.38 lb/hr = 228 lb

The next table shows the RTC requirement for the entire facility

Table C-8 Facility RTC Requirements, CEMS Certified after 1st Year Operation

Equipment	RTC (lb)
Gas Turbines (Two)	3,463,124
Auxiliary Boiler	3,201
Emergency Generator	252
Emergency Fire Pump Engine	228
Total RTC requirement	3,466,805

Subsequently the RTC required is 3,466,805 lbs.

If the facility is able to certify the NOx CEMS at the conclusion of the commissioning process, the RTC requirements is then:

Table C-9 Facility RTC Requirements, CEMS Certified after Commissioning

Equipment	RTC (lb)
Gas Turbines (Two)	486,912
Auxiliary Boiler	3,201
Emergency Generator	252
Emergency Fire Pump Engine	228
Total RTC requirement	490,593

The NOx RTC requirement is then ***490, 593*** lbs.

APPENDIX D MODELING ANALYSIS

MODELING DESCRIPTION

The applicant performed an initial screening level model to determine the worst case operating scenario for the gas turbines based on various operating loads and ambient conditions. This worst case scenario for the gas turbines was then used in the refined modeling, along with emissions from other equipment on site as appropriate. The following table shows, for the refined modeling, which equipment was included in the model for each applicable regulation:

Table D-1 Modeling Requirements

Regulation	Modeled Emissions
NSR	Gas turbines, duct burners and the boiler
PSD	All new NO_2 emitting equipment including gas turbine/duct burners, the boiler and diesel engines
1401 HRA	Facility-wide emissions of carcinogenic and toxic pollutants, including gas turbine/duct burners, diesel engine, the boilers
CEQA*	Facility-wide emissions, including gas turbine/duct burners, boiler, diesel engines

* Emissions during the construction phase were also modeled for CEQA purposes

For purposes of AQMD permitting requirements, only NSR, PSD, and Health Risk Assessment model results are considered. The entire facility and construction impacts model under CEQA fall under CEC jurisdiction.

EMISSION FACTORS AND STACK PARAMETERS

The following summaries reference the permit application support document when referring to appendices and tables.

GAS TURBINES

As noted above, a screening analysis was performed on the turbines to determine the worst case impacts. A total of seven scenarios were modeled (as shown in Appendix K of the AFC, Table K.5-1.) The results show that maximum impacts from the turbines occur with Case #5 with the following conditions:

- 100% load
- duct burners on
- evaporative cooler off
- 36° F, 60% relative humidity

The stack parameters are given in the next table.

Table D-2 Modeling Parameters – Gas Turbine Stack

Parameters	Value
Exhaust temperature	331.0 °K
Stack diameter	5.639 m
Exhaust flow	425.61 m^3/s
Exit velocity	17.04 m/s

The emission factors for the worst case operating conditions:

Table D-3 Modeling Parameters – Turbine Emissions Factors

Pollutants	Emissions
NOx, short-term	2.5 ppm, 2.86 g/s
NOx, long-term	2.0 ppm, 2.29 g/s
CO	6.0 ppm, 4.19 g/s
SO_2	0.22 g/s
PM10	0.003 grain/dscf, 2.01 g/s

These emission rates were then used in the refined modeling runs to determine both the short-term and long-term impacts. These emission rates were used along with emissions for the other equipment on site.

AUXILIARY BOILER

The new auxiliary boiler emissions were estimated based the manufacturer provided emission limits and acceptable BACT limits. Note there is a selective catalytic conversion (SCR) system and a CO catalyst dedicated to the boiler. The emission rates are calculated in the Appendix B. Annual emissions for long- term impacts are estimated assuming 3,000 hours annual operation. Below is a summary of the data used in the modeling, as given the Table K-3 of Appendix K-5 of the AFC.

Table D-4 Modeling Parameters – Auxiliary Boiler

Pollutant	Emissions	
	One-hour average	Annual Average
NOx	0.176 g/s(1)	0.060 g/s(4)
SOx	0.011 g/s(1)	0.004 g/s(4)
CO	0.617 g/s(1)	0.617 g/s(2)
ROG	NA	NA
PM10	0.113 g/s(3)	0.117 g/s(4)

(1) One-hour average, (2) 8-hour average, (3) 24-hour average, (4) Annual average

EMERGENCY GENERATOR

The emergency natural gas generator emissions are based manufacturer provided emission limits and applicable BACT emission limits. The following table shows the emissions used in the modeling [Appendix K-5 of the AFC, Table K.5-3]:

Table D-5 Modeling Parameters – Emergency Generator

Pollutant	Emissions	
	One-hour average	Annual Average
NOx	0.611 g/s, 4.85 lb/hr(1)	0.014 g/s, 0.48 lb/hr(4)
SOx	0.000 g/s, 0.00 lb/hr(1)	0.000 g/s, 0.00 lb/hr(4)
CO	0.815 g/s, 6.468 lb/hr(1)	0.102 g/s, 0.81 lb/hr(2)
ROG	N/A	N/A
PM10	0.003 g/s, 0.02 lb/hr(3)	0.001 g/s, 0.01 lb/hr(4)

(1) One-hour average, (2) 8-hour average, (3) 24-hour average, (4) Annual average

EMERGENCY FIRE PUMP ENGINE

The emergency fire pump engine emissions are based manufacturer provided emission limits and applicable BACT emission limits. The following table shows the emissions used in the modeling [Appendix K-5 of the AFC, Table K.5-3]:

Table D-6 Modeling Parameters – Emergency Fire Pump Engine

Pollutants	Emissions	
	One-hour average	Annual Average
NOx	0.000 g/s, 0.000 lb/hr(1)	0.003 g/s, 0.025 lb/hr(4)
SOx	0.016 g/s, 0.126 lb/hr(1)	0.001 g/s, 0.005 lb/hr(4)
CO	0.000 g/s, 0.000 lb/hr(1)	0.000 g/s, 0.000 lb/hr(2)
ROG	N/A	N/A
PM10	0.001 g/s, 0.01 lb/hr(3)	0.000 g/s, 0.000 lb/hr(4)

(1) One-hour average, (2) 8-hour average, (3) 24-hour average, (4) Annual average

COOLING TOWERS

The new cooling towers' PM10 emission rates are based on the designed flow rate of 169,847 GPM, a typical drift rate factor of 0.0005 percent, and the total dissolved solids (TDS) level of 7,800 ppm. The calculated emissions using these criteria are 0.0298 g/s per cell, with a total of 14 cells per cooling tower.

The applicant also conducted specialized modeling analyses for fumigation, gas turbine start-up, and gas turbine commissioning.

FUMIGATION MODELING

SCREEN3 was used to model one-hour impacts from the gas turbines/HRSGs using the full SCREEN3 meteorological data set, considering that inversion breakup fumigation is generally a short-term phenomenon. The inversion breakup fumigation impacts for two gas turbines/HRSGs and the combined stacks were modeled. The maximum combined results were then divided by two to determine the maximum impacts of a single gas turbine/HRSG. Results are in Appendix K-5 of the AFC, Table K.5-4.

Table D-7 Fumigation Modeling Results

Receptor Location	Equipment	NOx 1-hour ($\mu g/m^3$)	SO2 1-hour ($\mu g/m^3$)	SO2 3-hour ($\mu g/m^3$)	CO 1-hour ($\mu g/m^3$)	CO 8-hour ($\mu g/m^3$)
Maximum Gas Turbine Impacts	Single Turbine /HRSG	3.2	0.25	0.2	4.6	3.2
Maximum Gas Turbine Impacts	Two Turbines /HRSGs	6.4	0.5	0.4	9.3	6.4

PSD ANALYSIS

Please refer to the discussions included in the PSD section in the Rule Evaluation sections

HEALTH RISK ASSESSMENT

Emissions of the following pollutants are calculated using the emission factors from CARB CATEF database (except ammonia, which is based on 5 ppm slip), in conjunction with maximum hourly and annual fuel consumption rates. The following emissions are per turbine.

Table D-8 Modeling Results -Toxic Air Contaminants

Compounds	Emission Factor lb/MMscf	Emissions lb/hr	Emissions tons/year
Acetaldehyde	4.08E-02	0.1015	0.39
Acrolein	3.69E-03	0.0092	0.03
Ammonia	-	33.68	147.54
Benzene	3.33E-03	0.0083	0.03
1,3-Butadiene	4.39E-04	0.0011	0.00
Ethylbenzene	3.26E-02	0.0811	0.31
Formaldehyde	1.65E-01	0.4106	1.56
Hexane	2.59E-01	0.6445	2.45
Naphthalene	1.33E-03	0.0033	0.01
PAH-Anthracene	3.38E-05	0.0001	0.00
PAH-Benzo(a)anthracene	2.26E-05	0.0001	0.00
PAH-Benzo(a)pyrene	1.39E-05	0.0000	0.00
PAH-Benzo(b)flouranthrene	1.13E-05	0.0000	0.00
PAH-Benzo(k)flouranthrene	1.10E-05	0.0000	0.00
PAH-Chrysene	2.52E-05	0.0001	0.00
PAH-Dibenz(a,h)anthracene	2.35E-05	0.0001	0.00
PAH-Indeno(1,2,3-cd)-pyrene	2.35E-05	0.0001	0.00
Propylene	7.71E-01	1.9187	7.30
Propylene Oxide	2.96E-02	0.0737	0.28
Toluene	1.33E-01	0.3310	1.26
Xylene	6.53E-02	0.1625	0.62

APPENDIX E **<u>HEAT INPUT RATES AND FUEL CONSUMPTION</u>**

Heat input and fuel consumption rates of the facility equipment are summarized in the next table

Equipment	36 F, 66% R.H.		97 F, 31% R.H.	
	Heat Input MMBtu/hr	Fuel Usage MMscf/hr	Heat Input MMBtu/hr	Fuel Usage MMscf/hr
Gas Turbine	1,813	1.795	1702	1.685
Duct Burner	697	0.690	697	0.690
Auxiliary Boiler	129	0.128	129	0.128
Emergency Generator	564 lb/hr		564 lb/hr	
Emergency Fire Pump*		18.3 gal/hr		18.3 gal/hr

* diesel fuel

Note: Fuel consumption is based on fuel HHV of 1,010 Btu/scf.

APPENDIX F COOLING TOWER EMISSIONS

COOLING TOWER PM10 EMISSIONS

Parameters	Values
Cooling Tower Water Flow rate (GPM)	169,847
Drift Rate (%)	0.0005
Drift Amount (gal/min)	0.85
Drift Amount (lbs/hr)	424
TDS level (ppmw)	7800
PM Amount (lb/hr)	3.31

COOLING TOWER CARCINOGENIC AND TOXIC EMISSION ESTIMATES

Pollutants	Emission Rates (lb/hr)	Emission Rates (tons/year)
Arsenic	7.73e-5	3.39e-4
Beryllium	1.66e-5	7.26e-5
Cadmium	1.66e-5	7.26e-5
Chromium III	2.76e-5	1.21e-4
Copper	3.87e-5	1.69e-4
Lead	8.29e-5	3.63e-4
Manganese	5.52e-5	2.42e-4
Mercury	2.76e-6	1.21e-5
Nickel	1.10e-4	4.84e-4
Zinc	4.47e-4	1.96e-3

APPENDIX G - NSPS CALCULATIONS

1). NOx limit

Since turbine rating is greater than 100 MMBtu/hr, use:

$$STD = 0.0075 * \frac{14.4}{Y} + F$$

Where:

STD: allowable NOx emissions (percent by volume at 15% oxygen and on a dry basis)
Y: manufacturer's heat rate in kJ/watt-hr
F: NOx allowance for fuel bound nitrogen, 0 for natural gas with a nitrogen content < 0.015%w

$$Y = \frac{1813 * 10^6 \, Btu/hr * 1.055 \, kJ/Btu}{174 * 10^6 \, Watt} = 10.99 \, kJ/Watt-hr$$

$$STD = 0.0075 * \frac{14.4}{10.99} + 0 = 0.00983 = 98.3 ppm$$

2). SOx limit

STD =150 ppmv @ 15% Oxygen dry basis

APPENDIX H NH3 EMISSIONS FROM THE STORAGE TANKS

The tanks are equipped with pressure relief valves preset to open at 25 psig. Since internal pressure is not expected to exceed 25-psig breather loss through the pressure relief valves are not anticipated. Transfer (working) losses are considered negligible with the use of the vapor return line. The following calculation presents a sample calculation assuming a control efficiency of 99%.

Working loss calculation:

$$L_w = 0.001 * (M_v)(P)(K_n)(K_p)(Q)$$

Where,

$M_v = 17,$	Molecular Weight of Ammonia
$P = 4.28\ psia,$	True vapor pressure in PSIA
$Q = 384{,}000 gal / year = 9{,}143$ barrels/year	Yearly Turnover rate
$K_n = (180 + 24)/(6 * 24) = 1.41$	Tank Turnover Factor
$K_p = 1$	Product factor

Thus,

$L_w = 938$ lb/year

Uncontrolled Hourly emissions: 938 lb/year ÷8760 hr/year =0.11 lbs/hr
Controlled hourly emissions: 0.11 lbs/hr * (1-99%) = 0.001 lbs/hr.
30-day average emissions: 0.001 lbs/hr * 24 hrs/day = 0.02 lbs/day

The above calculation clearly demonstrates that emissions are negligible.

APPENDIX H NATURAL GAS DATA

The next table contains the natural gas analysis data provided by the applicant.

GAS COMPOSITION DATA
(from 06/00 to 09/00, grains/1 00 scf)

Out of State Suppliers Location	H2S			RSH			Total Sulfur Analyzed**			Total Sulfur*		
	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg
NN	0.000	0.000	0.000	0.001	0.080	0.012	0.001	0.080	0.012	0.056	0.105	0.082
Bl	0.004	0.015	0.009	0.019	0.080	0.056	0.024	0.093	0.065	0.039	0.093	0.066
B2	0.004	0.015	0.009	0.019	0.080	0.055	0.024	0.093	0.065	0.038	0.093	0.065
SN	0.000	0.000	0.000	0.016	0.144	0.079	0.016	0.144	0.079	0.044	0.144	0.088

* Includes estimated supplemental odorant based on border guidelines of 50/50 t-butyl mercaptan/thiophane
** Total Analyzed Sulfur includes H2S, mercaptans (RSH) and sulfides, before odorization
NN = North Needles, Bl = Blythe, B2 =Blythe, SN = South Needles

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

APPLICATION FOR CERTIFICATION FOR THE INLAND EMPIRE ENERGY CENTER	**Docket No. 01-AFC-17** **PROOF OF SERVICE** **(Revised 12/09/02)**

I, **Keith A. Muntz**, declare that on **March 3, 2003** , I deposited copies of the attached **Final Determination of Compliance (FDOC) from South Coast Air Quality Management District dated February 28, 2003** in the United States mail in Sacramento, CA with first class postage thereon fully prepaid and addressed to the following:

DOCKET UNIT

Send the original signed document plus 12 copies to the following address:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 01-AFC-17
DOCKET UNIT, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

In addition to the documents sent to the Commission Docket Unit, also send individual copies of all documents to:

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I declare that under penalty of perjury that the foregoing is true and correct.

(Signature)

* * * *

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