INLAND EMPIRE ENERGY CENTER PERMIT TO CONSTRUCT

COMPANY NAME AND ADDRESS

INLAND EMPIRE ENERGY CENTER, LLC (IEEC)
26226 Antelope Road
Romoland, CA 92585
SCAQMD ID #129816

Contact: John Gates, (951) 928-6905

EQUIPMENT LOCATION

INLAND EMPIRE ENERGY CENTER, LLC (IEEC)
26226 Antelope Road
Romoland, CA 92585

EQUIPMENT DESCRIPTION

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

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 1: COMBUSTION AND POWER GENERATION					
SYSTEM 1: GAS TURBINE COMBUSTION					
TURBINE, #1, NATURAL GAS, GENERAL ELECTRIC, MODEL S107H, COMBINED CYCLE, WITH DRY LOW NOx BURNERS, 2,597 MMBtu/HR (at 36 ºF) WITH: A/N: ~~439481~~ 456168	D1	C17	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005 BACT, RULE 1703]; NOx: (COMMISSIONING) 68.26 LBS/MMSCF (1) [RULE 2012]; NOx: 7.36 LBS/MMSCF (1) [RULE 2012]; NOx: 123 PPMV NATURAL GAS (8) [40CFR 60 SUBPART GG]; **CO**: 3.0 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407];	**A63.1,** A99.1, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, **D29.1,** **D29.2,** D82.1, D82.2, E193.1, E193.2,
GENERATOR, 405 MW	B11				
GENERATOR, #1, HEAT RECOVERY STEAM GENERATOR (HRSG)	B13				

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	PROCESSED BY J YEE	CHECKED BY

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				VOC: 2.0 PPMV (4) [RULE 1303-BACT]; VOC: 1.4 PPMV (7) [RULE 1303-OFFSET] **PM10**: ~~**10.0**~~ **7.5** LBS/HR (~~4~~ 7) [RULE 1303-~~BACT~~ OFFSET]; PM10: 0.1 GR/SCF (5) [RULE 409]; PM10: 11 LBS/HR (5) [RULE 475]; PM10: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 150 PPMV (8) [40CFR 60 SUBPART GG]; SO2: (9) [40CFR 72 – ACID RAIN]; H_2S LEVEL IN NATURAL GAS LESS THAN 0.25 GRAIN PER 100 SCF [RULE 1303-OFFSET]	E193.3, **E193.6** I296.1, K40.1, K67.1
STACK, #1 SERVING TURBINE AND HRSG #1, HEIGHT: 195 FT; DIAMETER: 22 FT, WITH: A/N: ~~439481~~ 456168	S19	C4			
TURBINE, #2, NATURAL GAS, GENERAL ELECTRIC, MODEL S107H, COMBINED CYCLE, WITH DRY LOW NOx BURNERS, 2,597 MMBtu/HR (at 36 °F) WITH: A/N: ~~439485~~ 456169 GENERATOR, 405 MW GENERATOR, #2, HEAT RECOVERY STEAM GENERATOR (HRSG)	D2 B20 B22	C18	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005 BACT, RULE 1703]; NOx: (COMMISSIONING) 68.26 LBS/MMSCF (1) [RULE 2012]; NOx: 7.36 LBS/MMSCF (1) [RULE 2012];NOx: 123 PPMV NATURAL GAS (8) [40CFR 60 SUBPART GG]; **CO**: 3.0 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; VOC: 1.4 PPMV (7) [RULE 1303-OFFSET]	**A63.1**, A99.1, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, **D29.1,** **D29.2,** D82.1, D82.2, E193.1, E193.2, E193.3, **E193.6** I296.2, K40.1, K67.1

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Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				PM10: ~~**10.0**~~ **7.5** LBS/HR (~~4~~ 7) [RULE 1303-~~BACT~~ OFFSET]; PM10: 0.1 GR/SCF (5) [RULE 409]; PM10: 11 LBS/HR (5) [RULE 475]; PM10: 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]	
STACK, #2, SERVING TURBINE AND HRSG #2, HEIGHT: 195 FT, DIAMETER: 22 FT A/N: ~~439485~~ 456169	S26	C5			
SYSTEM 2: AUXILIARY EQUIPMENT					
BOILER, AUXILIARY, NEBRASKA BOILER, MODEL NS-F-76, NATURAL GAS FIRED, ~~157~~ 152.12 MMBtu/HR, WITH LOW NOX BURNER WITH: A/N: ~~439492~~ 456170 BURNER, NATURAL GAS, TODD VARIFLAME, MODEL VII690VGXXXX, 152.12 MMBTU/HOUR	D3	C6	NOx MAJOR SOURCE	**NOx**: 7.0 PPMV (4) [RULE 2005 BACT, RULE1703]; NOx: 8.36 LBS/MMSCF (1) [RULE 2012]; **CO**: 50 PPMV (4) [RULE 1303 BACT]; CO: 400 PPMV (5) [RULE 1146]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 10 PPMV (4) [RULE 1303 BACT] **PM10**: 7.26 LBS/MMSCF (4) [RULE 1303-~~BACT~~ OFFSET]; PM10: 0.1 GR/SCF (5) [RULE 409]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GRAIN PER 100 SCF [RULE 1303-OFFSET]	A63.2, A99.2, A195.4, A195.5, A195.6, B61.1, C1.2, D29.4, D82.3, D82.4, E193.1, E193.3, **E193.6** I296.3, K40.2

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
STACK, HEIGHT: 100 FT; DIA: 4 FT, SERVING AUXILIARY BOILER, WITH: A/N: ~~439492~~ 456170	S31	C6			

BACKGROUND

Inland Empire Energy Center, LLC (IEEC) 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 would consist of two combustion turbine generators (CTG) and one steam turbine generator (STG) with a nominal total generating capacity of 670 MW. The combustion turbine generators were General Electric PG7251 (FB) gas turbines with heat recovery steam generators (HRSG) and duct burners. The power plant would also include an auxiliary boiler, a standby generator, an emergency fire pump engine, two ammonia storage tanks, cooling towers, stacks, and electric transmission facilities. As a part of the Title V permitting process, on Sept. 26, 2001 IEEC also submitted eleven applications to the South Coast Air Quality Management District (AQMD). The AQMD application numbers were 391423-391432. The AQMD issued a Final Determination of Compliance (FDOC) on February 28, 2003. An addendum to the FDOC was issued by the AQMD on April 8, 2003. The CEC approved the power plant project on December 17, 2003. After the CEC approval the IEEC decided to put the project on hold. Permits to Construct to be issued by the AQMD for the proposed 670 MW plant were also put on hold accordingly.

On February 3, 2005 IEEC submitted a new set of applications to the AQMD for a change in the plant design. The applications were deemed complete on February 22, 2005. The new design substitutes the GE PG7251(FB) gas turbine with a more fuel efficient model S107H combined cycle system. The S107H is an integrated power plant that includes gas turbine, HRSG, and steam turbine. Unlike the previous configuration of two gas turbines and one steam turbine, the current design uses two GE S107H turbines and it eliminates the duct burners. Each S107H combined cycle system has a net generating capacity of 405 MW while the combined net capacity is 810 MW. Similar to the previous design, Selective Catalyst Reduction (SCR) systems and CO oxidation catalysts will still 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 auxiliary boiler (157 MMBtu/hr) will be installed to provide steam for serving the turbine shaft seals, condenser sparging, and for auxiliary purposes as needed. Emissions from the boiler will be controlled with a separate SCR system. Two 8-cell, mechanical draft evaporative cooling towers are to be built to provide cooling for the turbine condensers. Additional auxiliary equipment also include two diesel fired 2,000 kW standby generators and a 300 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 nearby the Romoland Elementary School that serves some 800 children. The distance between the school and the facility is over 1,000 feet (about 1,200 feet). Due to the site's closeness to the school the Romoland School District had intervened during the original CEC certification process.

The EPA has delegated to the AQMD limited PSD authority specific for this project. The AQMD has agreed to accept the delegation. The agreement is detailed in a memorandum signed by AQMD EO Barry Wallerstein and Deborah Jordan of US EPA on March 30, 2005. As such, the AQMD permit is also a PSD permit.

AQMD issued the initial PSD/RECLAIM/Title V facility permit to construct on August 5, 2005 for construction of an 810 MW power plant. On February 2, 2006, AQMD issued IEEC a minor modification to the RECLAIM/Title V and an administrative PSD facility permit granting an extension of the 6 month time period to 12 months to negotiate a Memorandum of Understanding with the U.S. Forest Service.

Compliance Review: A check in the Inspector's file shows no actions to date.

NEW APPLICATIONS

On April 21, 2006, AQMD received 4 applications from IEEC for change of condition for both turbines, the auxiliary boiler, and a Title V minor modification. In March 2005, IEEC provided AQMD with PM10 source test data from GE F-class (7F) combustion turbines as the support basis for their proposed emission rate of 10 lbs/hour or 0.00385 lbs/MMBtu for the new H-class (7H) turbine. In April 2005, GE conducted source testing on the 9H turbine operating in Baglan Wales. The Wales unit was tested by the Avogadro Group, a California based test firm, using EPA methods 201a and 202, methods AQMD source testing has typically accepted for determining PM10 from gas turbines.

The 9H is the 50 Hz version of the 7H 60 Hz turbine proposed at IEEC. According to GE literature, gas turbines designed for 50 Hz service run at 3000 RPM. Because of the lower speed (compared to the 60 Hz, 3600 RPM turbines) and equal tip speeds on the last stage blading (a technological limit), the 50 Hz turbines are much larger in size than the 60 Hz machines. As a result, much more power can be produced. Although the maximum energy output of the 9H unit is 20% higher (480 vs 410 MW), the 9H and 7H units have similar combustion characteristics. Both operate at a firing temperature of 2,600 ^oF with a pressure ratio of 23 to 1 and net efficiency of 60%. Both use a single shaft to generated electricity from a single generator from both mechanical and steam expansion energy sources. The 7F units (263 MW with steam turbine) operate at a firing temperature of 2,400 ^oF with a pressure ratio of 15 to 1 and net efficiency of 56%. The 7F units will generally have two separate generators, one servicing the gas turbine and one for the steam turbine.

Based upon the results of these tests, and GE's letter dated May 8, 2006, IEEC has proposed and AQMD agreed to lower their PM10 emission rate from 10 lbs/hour to 7.5 lbs/hour or 0.00288 lbs/MMBtu. In addition, IEEC has requested AQMD to place a combined daily operation limit for the 2 turbines and aux boiler. This condition would limit the sum of operating hours to 60 during any calendar day. Current emission limit conditions are based upon 30 day monthly averages as required under Rules 1303 and 1313.

Table 1 : Summary of Applications and Processing Fees

A/N	Submittal Date	Deemed Complete	Equipment	Fee Schedule	Processing Fee	Rule 301Y XPP	Total
456168	4-21-06	5-11-06	Gas Turbine D1	G	$8,220.94	1.5	$12,331.41
456169	4-21-06	5-11-06	Gas Turbine D2	G	$4,110.47	1.5	$6,165.71
456170	4-21-06	5-11-06	Aux Boiler D3	E	$3,318.36	1.5	$4,977.54
456166	4-21-06	5-11-06	Title V Appl	N/A	$1,267.94	N/A	$1,267.94
							$24,742.60

IEEC is a Title V facility thus this change in condition will require an appropriate revision action. Since the change of condition does not result in any increases in emission, the revision in the Permit is classified as a Minor Revision as described under Rule 3005 – Permit Revisions. In addition, after consultation with EPA staff on April 21, 2006, AQMD has determined that the proposed modification is an administrative change to the PSD permit. Based on the PSD agreement between AQMD and US EPA, the AQMD has agreed to handle the administrative revisions to the PSD permit. Thus, AQMD will process the PSD administrative change associated with these applications. The AQMD permit functions both as a Title V and PSD permit.

DISCUSSION

AQMD has reviewed the proposal to limit the hours of operation per day and to lower PM10 emission limits based upon GE's letter dated May 8, 2006 and the recent source test conducted on a similar unit in Baglan, Wales. The test was performed using EPA Methods 201a and 202, methods which have been typically accepted by AQMD for gas turbines tested in the AQMD and large gas turbines tested in both Bay Area AQMD and Feather River AQMD in California. The test was conducted by a California test firm familiar with the PM10 test method. In addition, the test firm has tested many large F-class turbines within California.

AQMD source testing staff has reviewed the tests results and have qualitatively determined that the overall approach used was appropriate for PM10 emissions (see memo dated May 11, 2006). Staff also stated that certain procedures differ from methods deemed acceptable for AQMD purposes. The sampling methodology was modified by heating the cyclone and filter to 320 F, which is significantly above the stack temperature of 185 F. AQMD source testing staff believes that this modification was done to exclude capture of sulfuric acid mist on the filter, and understates the PM10 emission rate for AQMD purposes. Additionally, staff indicated that the gas properties estimated by Methods 201A are altered by the higher temperature as stack gas enters the cyclone, which could affect cyclone efficiency. Staff is unclear from the data provided whether a high or low bias will result due to the higher temperatures within the cyclone. However, upon further evaluation and discussion with source testing staff, it has been determined that since the natural gas used for the test in Wales contained significantly higher sulfur content than the natural gas proposed to be used by the IEEC project (0.64 compared to 0.25 gr/100scf, respectively), that the effect of heated cyclone and filter would be minimized with respect to the lower sulfur content natural gas required to be used by IEEC.

The Wales tests were conducted in triplicate at full load, each with a 5 hour sample collection run. The results indicate an average PM10 emission level of 5.8 lbs/hour or 0.00212 lbs/mmbtu for the 9H unit. The applicant believes the 5.8 lb/hour PM10 emission rate is equivalent to 4.5 lbs/hour for the 7H unit after considering a 1.3-to-1 exhaust flow ratio between the 9H and 7H units. The 9H tests at full load ranged from 8.218 lb/hour to 4.297 lb/hour. Based upon the 1.3-to-1 ratio, the maximum scaled emissions for a 7H unit would be 6.322 lb/hour, a level which is below the proposed 7.5 lb/hour. GE, the manufacturer of the turbine and a partner in the IEEC project, has in their May 8, 2006 letter to the AQMD proposes and supports the 7.5 lb/hour PM10 emission rate for the turbine installation at IEEC. GE has also indicated that although they stand behind the 7.5 lbs/hour PM10 emission rate for this particular installation, they cannot at this time stand behind and support this emission rate for every installation since they will not have the same level of control over operation and quality control for testing at other installations.

AQMD has reviewed the proposed lower 7.5 lb/hour PM10 emission rate and has determined based upon 1) the applicant/manufacturer's letter of support for the 7.5 lb/hour emission limit, 2) the applicant/manufacturer's scaled emission estimates based on an actual source test for a similar turbine, that the proposed PM10 emission rate is acceptable to AQMD. AQMD will reflect this and the proposed limitation in the daily maximum hours of operation in our revised emission calculations and permit conditions. Similar to the original permit, PM10 source testing will be required both initially upon during the units' start-up year and once every three years thereafter. The initial testing and the tri-annual testing will be required to be performed in triplicate.

The condition to limit the cumulative operation for both the 2 turbines and the auxiliary boiler to 60 hours in any calendar day does not change the potential to emit (30-day calendar average for CO, SOx, VOC and PM10 and the maximum hourly NOx emissions) nor lessens any current rule requirements under Regulation 13 and Rule 2005 NSR. The operator has purely elected to limit operations defined on a daily basis only. AQMD has determined that the proposed change will allow for continued compliance with AQMD rules. The following table shows the pre-versus post-modification 1-day maximums for the cumulative emissions for all three units based on the following:

Existing P/Cs dated 8/5/05

- Each turbine in operation 24 hours/day with PM10 = 10 lbs/hour
- Aux boiler in operation 24 hours/day with PM10 = 7.26 lbs/mmscf

Proposed Change of Condition Worst Case Scenario: 60 hours cumulative

- Each turbine in operation 24 hours/day with PM10 = 7.5 lbs/hour
- Aux boiler in operation 12 hours/day with PM10 = 7.26 lbs/mmscf

As shown in the below table, there will be a net decrease in the 1-day maximums although the 30-day average emissions remain the same with the exception of PM10 for the gas turbines.

Table 2
Cumulative 1-day Maximum Emissions in lbs/day for Gas Turbines and Auxiliary Boiler

	Existing P/C dated 8/5/05	Proposed Change of Condition
NOx	936	920
CO	963	894
PM10	507	373
VOC	330	322
SOx	90	89

PROCESS DESCRIPTION

GAS TURBINE GENERATORS (A/N456168 AND A/N445169)
The power plant will utilize combined-cycle gas turbine generators for power generation. The gas turbine (Brayton) cycle is combined with a steam turbine (Rankine) cycle for improved thermal efficiency. The power plant will consist of two GE S107H combined cycle gas turbines. The S107H is an integrated package that includes a combustion gas turbine, a heat regeneration steam generator (HRSG), and a steam turbine. The steam turbine and the gas turbine share a common shaft that drives a single generator.

The S107H series combined cycle gas turbines are the most advanced commercially available gas turbines currently produced by GE. Compared with 7F series gas turbine, the S107H series turbines utilize new technologies that allow a higher firing temperature and pressure, and thus produce a higher thermal efficiency. According to a GE publication, the heat rate is 5,690 Btu/KWh for the S107H series turbines whereas the comparable heat rate is 6,020 Btu/KWh for the FA turbines, 5,950 Btu/KWh for the FB turbines.

The gas turbines will be fired exclusively with pipeline natural gas. The natural gas will be brought to the facility through construction of a new natural gas pipeline. The natural gas pipeline is part of the CEC certification and it has been approved by CEC in 2003. Each S107H unit produces 405 MW of power at base load under average ambient conditions with inlet air cooling. The combined power output is 810 MW. At base load fuel consumption is 2,597 MMBtu/hr when ambient temperature is at 36 F. Fuel consumption is 2,502.9 MMBtu/hr at average ambient conditions.

Table 3 Combustion Gas Turbine and HRSG Specifications

Parameter	Specifications
Manufacturer	General Electric
Model	S107H
Fuel Type	Pipeline Natural Gas
Natural Gas Heating Value (HHV)	1,014.6 Btu/scf
Gas Turbine Heat Input (HHV, per unit)	2,597 MMBtu/hr(1)
Fuel Consumption (One unit)	2.560 MMscf/hr
Gas Turbine Exhaust Flow (Base load, one unit)	1,000,305 DSCFM(1)
Average Fuel Consumption (One unit)	2,502.9 MMBtu/hr
Net Power Generation (One unit)	405 MW
Net Plant Heat Rate, LHV	5,783 Btu/kW-hr(2)
Net Plant Efficiency	59.0% (LHV based)(3)

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

(2) Based on the following calculations: 2,597*0.90183/405 = 5.783 MMBtu/MW-hr, or 5,783 Btu/kW-h. The 0.90183 coefficient is the ratio of LHV over HHV of natural gas, provided by the applicant.

(3) Based on the following calculations: 3,413/5,783 = 59.0%. 1 kW-hour = 3,413 Btu

AIR POLLUTION CONTROL (APC)

Multiple emission control methods are utilized for the combustion gas turbines. 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, VOC, and PM10 are small. The 1-hour average NOx concentration is 15 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, 1-hour average, dry basis at 15% O_2. VOC emissions are limited to 2.0 ppmv, dry basis at 15% O_2, 1-hour average. The combustion gas turbines minimize SOx and PM10 emissions by use of commercial grade natural gas.

SCR/CO Catalysts for the Gas Turbines

For the gas turbines the IEEC has proposed to use an SCR system with a Halder-Topsoe catalyst. The specifications of the gas turbine SCR systems are provided in Table 4. The SCR is expected to achieve an 85% NOx removal efficiency, i.e., reduction of NOx from 15 ppmv prior to SCR down to 2 ppmv after SCR. The SCR will be located at downstream of the HP evaporator section of the HRSG. Temperature window is approximately between 400°F and 720°F.

Table 4 Selective Catalyst Reduction (SCR)

Catalyst Properties	Specifications
Manufacturer	Halder-Topsoe
Catalyst Description	Ti-V-W Ceramic
Catalyst Type	Honeycomb
Catalyst Volume	2,048 ft^3
Dimensions	64’8” (H) X 33’0”
Space Velocity	23,000 hr^{-1}
Area Velocity	82,021 ft/hr
Ammonia Injection Rate	40 – 870 lbs/hr, 100% ammonia
NOx removal efficiency	~85%
NOx level at the outlet	2.0 ppmv, dry basis at 15% O_2, 1 hour average
Temperature at the outlet	400 to 720 deg. F
SCR Reactor Temperature	400 to 720 deg. F
Unit Cost	$1,275,000
SO_2 oxidation rate	3%

Each gas turbine will also be equipped with a CO oxidation catalyst. The CO oxidation catalyst is permitted together with the SCR catalyst. The IEEC has indicated 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, and it will be at the upstream of the SCR catalyst. Operating temperature window is between approximately 600 °F and 1,100 °F.

The CO oxidation catalyst also reduces VOC emissions. As a part of the catalyst specifications the VOC emissions is 2 ppmv, dry basis at 15% O_2.

Table 5 CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	Engelhard
Catalyst Type	Pt
Catalyst Volume	290 ft^3
Dimensions	64’8”(H) X 33’0” (W)
Space Velocity	218,000 hr^{-1}
Area Velocity	82,000 ft/hr
CO removal efficiency	$\gtrsim$80%
CO	3 ppmv, 1-hour average, dry at 15% O_2
VOC	2 ppmv, 1-hour average, dry at 15 % O_2
CO Catalyst Total Cost	$865,000
Catalyst Replacement Cost	$690,000

Auxiliary Boiler (AN456170)

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) turbine gland steam (necessary to keep air out of the steam turbine), 2) steam turbine cooling during startups and shutdowns. 3) condenser hotwell sparging, and 4) deaeration steam for auxiliary boiler deaerator (to assist in removal of oxygen from the boiler feed water). The boiler is not expected to operate for more than 600 hours in a year.

The IEEC has not finalized the selection of the auxiliary boiler. According to the IEEC it is likely to be a Nebraska Boiler and the heat input rate will be 152.12 MMBtu/hr. The boiler will be fired with commercial grade natural gas, and will have a SCR for NOx 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.

Table 6 Auxiliary Boiler Specifications

Catalyst Properties	Specifications
Manufacturer	Nebraska Boiler
Model Number	NS-F-76
Number of Burner	1
Burner Type: Low NOx	Todd Variflame, model VII690VGXXX
Maximum heat input	152.12 MMBtu/hr
Fuel	Natural Gas
Stack Parameters	100 ft height X 4 ft diameter

SCR Catalyst for the Auxiliary Boiler

For the auxiliary boiler the IEEC has proposed to use an SCR system manufactured by Peerless Manufacturing using a honeycomb vanadium/titanium ceramic catalyst. The following are the specifications of the SCR system. Temperature window is approximately between 450°F and 800°F.

Table 7 Selective Catalyst Reduction (SCR)

Catalyst Properties	Specifications
Manufacturer	Peerless Manufacturing
Catalyst Description	Vanadium/Titanium Ceramic
Catalyst Type	Honeycomb
Dimensions	7’4” X 4’3” X 4’

Catalyst Properties	Specifications
Catalyst Volume	115 ft^3
Space Velocity	36,000 hr^{-1}
Area Velocity	51,480 hr^{-1}
Temperature at the Outlet	595 ºF
SCR Temperature Range	450-800 F
Unit Cost	$575,000
SO_2 Conversion Rate	3%

AUXILIARY EQUIPMENT

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 vaporization chamber will be heated by hot exhaust gas from the HRSG. Once vaporized, the aqueous ammonia is sent to the HRSG injection nozzles and to the SCR by using a forced draft electric fan. The system is equipped with a second ammonia injection fan that serves as a backup to the primary unit.

Exhaust Stacks for Gas Turbines

Exhaust stacks are not individually permitted equipment. They are a part of the gas turbine permits. Each gas turbine and HRSG will be equipped with a 195-ft tall, 22-ft diameter stack. The stack data are shown in the next table.

Table 8 Gas Turbine Stack Parameters

Stack Parameters	Specifications
Stack Diameter	22 FT
Stack Height	195 FT
Stack Exhaust Temperature	150.6 °F, peak load, 36 F ambient temperature
Stack Gas Flow Rate	1,000,305 SCFM

The stack height must comply with the applicable regulations and rules. The stack height is unchanged from that included in the previous project design approved by the District.

EMISSIONS

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

EMISSIONS FROM THE GAS TURBINES

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 9 Operating Modes of the Combustion Gas Turbines

Mode	Description
Commissioning	This is the process of "tuning in" and testing 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 will take up to six months to commission the plant. This is somewhat longer than the typical process, and is due to the fact that this is the initial installation of these turbine models. The S107H System will initially be commissioned with extensive plant and gas turbine instrumentation to further characterize the initial operation of the first 60Hz GE H System. It is expected that some instrumentation and associated hardware will be replaced with non-instrumented components prior to normal operation and the remaining effected components will be replaced with non-instrumented components after normal operation during a planned maintenance shutdown.
Startup	The application has specified two types of startups, hot and cold. Cold startup takes up to 6 hours while hot startup takes 1 hour. While the total pounds emitted over the start period is different for a hot and cold start, the application assumes a single worst case lbs/hr emission level 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 VOC of 2 ppm. Emissions may vary due to ambient conditions.
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 of the 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, two turbines are expected to be commissioned over approximately a four to six month period. Emission rates during the commissioning period will be higher than during normal operations because the combustors have not been finely tuned, the SCR systems may not be operational, and increased start-up shutdown and part load operations. To the extent practical, the combustors will be preliminarily tuned to minimize emissions. Refer to Appendix A for the detailed calculations of the emissions during the commissioning period. As determined in Table A-8 of Appendix A, the next table contains the equivalent NOx and non-RECLAIM pollutants emissions factors during the commissioning period.

Table 10 Emissions and Emission Factors During the Commissioning Period

Emissions	NOx	CO	VOC	PM10	SOx
Total Emissions (lbs), Both Turbines	85,729	27,871	2,176	3,814	931
Total Hours (hr), Both Turbines	509	509	509	509	509
Total Fuel (MMscf), Both Turbines	1,256	1,256	1,256	1,256	1,256
Emission Factor (lb/MMscf)	68.26	22.19	1.73	3.04	0.74

Emissions of Gas Turbine Baseload Operation

Emission limits are subject to the requirements of BACT. Refer to the Regulation XIII and Rule 2005 evaluations in the previous application 439481 for discussion of the appropriate BACT limits. The next table provides the applicable BACT emission limits for the combustion gas turbines. These limits do not apply at startup, shutdown, or during the commissioning period. 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 (1,014.6 Btu/scf) and the combustion gas turbine heat input rate. Detailed calculations are included in Appendix A.

Table 11 Emission Limits of the Combustion Gas Turbine, 36 °F

Pollutant	Emissions (ppmv @15%O_2)	Emissions (lbs/MMBtu)	Emissions (lbs/MMscf)
NOx, prior to SCR	15[(1)] , 1-hour average	0.0544	55.15
NOx, after SCR	2.0[(2)], 1-hour average	0.0073	7.36
CO	3.0[(2)], 1-hour average	0.0066	6.72

Pollutant	Emissions (ppmv @15%O_2)	Emissions (lbs/MMBtu)	Emissions (lbs/MMscf)
VOC	2.0(2), 1-hour average	0.0025	2.56
SOx	0.14(2)(3)	0.0007	0.71
PM10	(4)	0.00288	2.93
NH3	5.0(2), 1-hour average	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). PM10 BACT for gas turbines is exclusive use of Natural Gas. The 7.5 lb/hour or 0.00288 lbs/MMBtu emission levels are used for emissions calculations and reporting under Rule 1303

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 facility has also provided emission rates of hot startups and cold startups. The next table shows a summary of the emissions from one gas turbine.

Table 12 Maximum Emission Rates– One Combustion Gas Turbine

Conditions	NOx		CO(6)		PM10	VOC		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,	18.84	18.84	17.20	11.47	7.5	6.55	4.59	1.83
Hot Start(5) (Single Unit in Startup)	408	125	95	50	7.5	16	16	1.83
Hot Start(5) (Both Units in Startup)	275(7)	125	95	50	7.5	16	16	1.83
Cold Start(5) (Single Unit in Startup)	408	125	95	50	7.5	16	16	1.83
Cold Start(5) (Both Units in Startup)	275(7)	125	95	50	7.5	16	16	1.83

(1) 1-hour average, NOx level of 2.0 ppmv, CO of 3.0 ppmv, and VOC of 2.0 ppmv
(2) 30-day average, NOx level of 2.0 ppmv, CO of 2.0 ppmv, VOC of 1.4 ppmv
(3) PM10 includes both the front and back halves.
(4) Natural gas H_2S concentration level of 0.25 grain per 100 scf.
(5) Hot start duration is 1 hour and cold start duration is 6 hours.
(6) CO emissions rates are provided by the applicant. CO emissions are to be subject to CEMS monitoring
(7) Based on a combined NOx emission rate of 550 lbs/hr for the two gas turbines.

<u>EMISSIONS FROM THE AUXILIARY BOILER</u>

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

Table 13 Emission Limits of the Auxiliary Boiler

Equipment	CO	NOx	PM10	VOC	SOx
Auxiliary Boiler	50 ppmv at 3% O_2	7 ppmv at 3% O_2	7.26 lb/MMscf Natural Gas	10 ppmv at 3% O_2	0.7 lb/MMscf Natural Gas

The ammonia (NH3) emission limit of the auxiliary boiler is 5 ppmv, corrected to 3% O2, dry basis. Hourly emissions from the auxiliary boiler are calculated in Appendix B and are summarized in the next table.

Table 14 Maximum Hourly Emissions – Auxiliary Boiler

Equipment	CO (lb/hr)	NOx (lb/hr)	PM10 (lb/hr)	VOC (lb/hr)	SOx (lb/hr)
Auxiliary Boiler	5.71	1.32	1.12	0.65	0.11

MAXIMUM DAILY EMISSIONS

Based on the proposed maximum daily combined hours of operation for the gas turbines and the auxiliary boiler and the lower proposed PM10 emission rates for the gas turbines, the maximum potential daily emissions have reduced under the proposed operation as shown in Table 2 and restated in the following table.

Table 2

Cumulative 1-day Maximum Emissions in lbs/day for Gas Turbines and Auxiliary Boiler

	Existing P/C dated 8/5/05	Proposed Change of Condition
NOx	936	920
CO	963	894
PM10	507	373
VOC	330	322
SOx	90	89

30-DAY AVERAGE EMISSIONS OF NON-RECLAIM POLLUTANTS

For non-RECLAIM pollutants the 30-day average emissions are determined for new source review (NSR) purposes.

For the gas turbines the 30-day average emissions are calculated by assuming a 31-day period that includes 31 startup hours and 713 base load hours. Detailed calculations are included in Appendix A and B. A summary is given in the next table.

Table 15 30-Day Average Emissions from One Gas Turbine

Pollutants	Emission Factor (lbs/hr)	PTE (lbs/day)	Monthly Emission (lbs/month)
CO	11.47	324	9,728
VOC	4.59	126	3,769
PM10	7.5	186	5,580
Sox	1.83	45	1,362

For the auxiliary boiler, the following operating schedule is used in the 30-day averaged emissions calculations: Auxiliary Boiler: 600 hours per year, 195 hours maximum per month The emissions are calculated in Appendix B and shown in the next table.

Table 16 30-Day Average Non-RECLAIM Emissions, Auxiliary Equipment

Equipment	CO (lb/day)	PM10 (lb/ day)	VOC (lb/ day)	SOx (lb/ day)
Auxiliary Boiler	37	4	7	1

ANNUAL NOx EMISSIONS

The RECLAIM program requires that a facility shall provide RECLAIM trading credits (RTC) to offset the total facility NOx emissions for each year of operation. NOx emissions of the first year and the following years are calculated in Appendix A and Appendix B. RTC requirements will be based on a 1:1 offset ratio of the actual NOx emissions. Since the first year includes the commissioning period the first year of operation is broken into the commissioning period and the remaining months of normal operations. The remaining months' operation schedule is prorated based on the annual schedule of 400 hours of startups and 8,360 hours of baseload operation. Emissions and Detailed RTC calculations are included in Table A-10 and A-11. Results are presented in the next table.

Table 17 NOx RTC Calculations – Entire Facility

Equipment	NOx RTC (lbs), 1st Year	NOx RTC (lbs), after 1st Year
Commissioning, 1st Turbine	54,569	0
Commissioning, 2nd Turbine	31,160	0
Remaining months, 1st Turbine	111,043	158,943
Remaining months, 2nd Turbine	121,058	158,943
Auxiliary Boiler	790	790
Standby Gen #1:ref from prev appl	1,946	1,946
Standby Gen #2:ref from prev appl	1,946	1,946
Emerg Fire ICE:ref from prev appl	172	172
Grand Total	**322,684**	**322,741**

It is required that the facility certify the NOx CEMS at the conclusion of the commissioning period and prior to baseload operation. The commissioning period takes four to six months. The facility shall have sufficient time to certify the NOx and CO CEMS.

1^{st} year NOx RTC requirement:	322,684 lbs
Each following year NOx RTC requirement:	322,741 lbs

RULES EVALUATION

40CFR PART 60 SUBPART Da – NSPS FOR THE AUXILIARY BOILERS

The auxiliary boiler is not subject to this performance standard because its maximum heat input of 157 MMBtu/hr is less than the 250 MMBtu/hr threshold established by this regulation.

40CFR PART 60 SUBPART Db – NSPS FOR THE AUXILIARY BOILERS

The auxiliary boiler is subject to this performance standard because its maximum heat input of 157 MMBtu/hr is greater than the 100 MMBtu/hr threshold established by this regulation. The NOx limit specified by this rule, under provision §60.44b for natural gas fueled burners, is 0.2 lb/MMBtu. The BACT limit of 7.0 ppmv (0.0084 lb/MMBtu) is more stringent than the 0.2 lb/MMBtu limit. Thus, compliance is expected.

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 $2{,}597(10^6)$ Btu/hr X 1,055 joules/Btu = 2,740 gigajoules/hr. The applicable standards are determined in Appendix F, and the results are:

NOx = 123 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 SOURCES

As determined in Appendix B of previous gas turbine application no. 439481, the facility total HAP emissions from all HAPs are 21 tons per year (tpy). The facility total maximum HAP emissions from a single HAP are 8.24 tpy (formaldehyde). Thus, because HAP emissions from the IEEC facility are below the major source thresholds of 10 tons per year for a single source or 25 tpy for a combination of HAPs, the IEEC facility is not major source of HAP. Thus, the gas turbines and the auxiliary equipment are exempt from this regulation.

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 VOC emissions, and will use control equipment to meet BACT limits for NOx and CO. The external control equipment for NOx and CO consists of the selective catalyst reduction (SCR) and oxidation catalysts. VOC 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 VOC limit this regulation would not apply for VOC.

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 VOC limit will be determined by periodic source testing. Compliance with this regulation is expected.

40CFR PART 72 – ACID RAIN PROGRAM

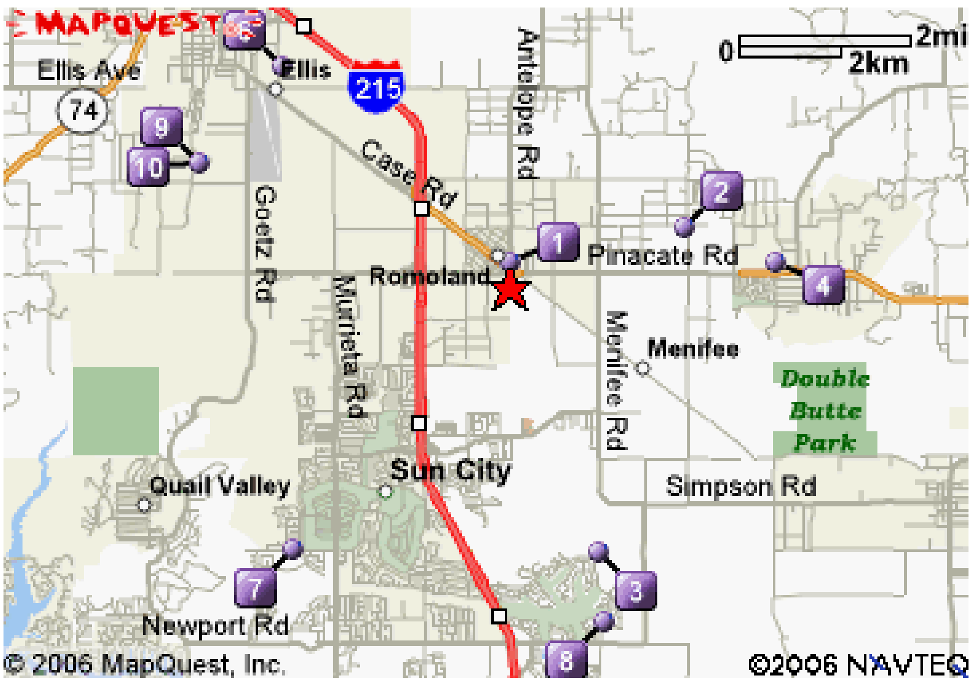
This facility is subject to the requirements of the Federal Acid Rain program. The facility is required to apply for a federal permit (Title IV). The acid rain program is similar to RECLAIM in that facilities are required to cover SO_2 emissions with "SO_2 Allowances" (similar to RTCs), or purchases 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.

RULE 212 – STANDARDS FOR APPROVING PERMITS

The condition changes to these permits results in PM10 emissions that are lower than permitted level in the permit to construct issued on 8-5-05 as well as lower potential daily emissions from the project for all pollutants. Schools located nearest to the facility are listed and graphed below according to a search through Mapquest. It was noted during the CEC's AFC process that Romoland Elementary School is greater than 1,000 feet from the IEEC facility. Since the applications for condition change will result in emissions below the previous level described in the public notice for the permit to construct issued on 8-5-05, and the facility is located more than 1000 feet from the outer boundary of a school, the rule requirements for public notice is not triggered.

Name of School	Address	Distance from IEEC, miles (ft)
1. Romoland Elementary School	25890 Antelope Rd, Romoland	0.31 (1600)
2. Harvest Valley Elementary School	29955 Watson Rd, Sun City	2.10

3. Freedom Crest Elementary School	29282 Menifee Rd, Menifee	3.06
4. Romoland School District	25900 Leon Rd, Homeland	3.06
5. Simily's (Private School)	P.O. Box 514, Homeland	3.56
6. Turnkey Schools of America	884 S Redlands Ave, Perris	3.60
7. Ridgemoor School	25455 Ridgemoor Rd, Sun City	3.79
8. Menifee Elementary School	30205 Menifee Rd, Menifee	3.80
9. Pincate Middle School	1990 S A St, Perris	3.84
10. Bob Reiner Elementary School	2221 S A St., Perris	3.84



<u>RULE 218 – CONTINUOUS EMISSION MONITORING</u>

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. The facility needs to install CO CEMS for the two gas turbines and for the auxiliary boiler. NOx emissions monitoring is discussed under RECLAIM rules.

<u>RULE 401 – VISIBLE EMISSIONS</u>

This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann NO. 1), as published by the US Bureau of Mines. Violations of the visible emission requirements are not expected from the natural gas fired gas turbines and auxiliary boiler.

RULE 402 – NUISANCE

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury of damage to business or property. Operation of the gas turbines and the auxiliary boiler are not expected to create a public nuisance based on experience with other turbines and boilers operating under normal conditions.

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. During CEC’s AFC process, IEEC conducted a modeling analysis of the air quality impacts during the construction 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 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. Compliance with this rule is expected.

Table 18 Modeled Maximum Construction Impacts

Pollutants	Avg. Time	Maximum Impacts (μg/m^3)	Background (μg/m^3)	Total Impact (μg/m^3)	State Standard (μg/m^3)	Federal Standard (μg/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 of the gas turbines will be controlled by an oxidation catalyst, and are expected to be less than 3 ppmv at 15% O_2 level. The CO emissions of the boiler will be 50 ppmv at 3% O_2. Compliance is expected, and will be verified through CEMS data.

RULE 409 – COMBUSTION CONTAMINANTS

This rule limits PM emissions to 0.1 grain/scf calculated at 12% CO2 or 0% O2. This is based upon the relation between CO2 and O2 concentration derived based on the EPA Method 19 F-factors. For natural gas combustion, the formula reduces to %CO2 = 0.5713 (20.9-%O2) and is an attached graph for easier reference. The equipment is expected to meet this limit based on the calculations shown below:

For the gas turbine, the PM10 emissions are 7.5 lbs/hr at 15% O2 for one turbine. Estimated exhaust gas using the data provided in Table 7:

Exhaust = 1,000,305 DSCFM = 60 MMdscf/hr

$$\text{PM10} = \frac{7.5*7000}{60*10^6} x \frac{20.9-0}{20.9-15} = 0.00308 \text{ grain/dscf}$$

For the boiler, similar calculation can be done by using the emissions data calculated in Appendix B.

Exhaust = 1.560 MMscf/hr

PM10 = 1.12 lb/hr

$$\text{PM10} = \frac{1.12*7000}{1.56*10^6} x \frac{20.9-0}{20.9-3} = 0.006 \text{ grain/dscf}$$

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 D) 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 or the concentration limit is met. Mass PM10 emissions from each of IEEC turbine's are estimated at 7.5 lbs/hr. Thus compliance is anticipated. Compliance will be verified through the initial performance test as well as periodic testing required by Title V.

RULE 1146 – EMISSIONS OF OXIDES OF NITROGEN FROM INDUSTRIAL BOILERS
This rule applies to the auxiliary boiler. The NOx emissions requirements are superseded by the RECLAIM rules. The CO emission limit is 400 ppmv. Compliance is expected.

REGULATION XIII – NEW SOURCE REVIEW
Rule 1301(b) specifies that the provisions of this Regulation apply to the installation of a new source or modification of an existing source which may cause the issuance of any non-attainment air contaminant. Although the proposed change in conditions is a change to the current permit to construct for a new source, the action results in lower hourly PM10 emissions from Turbines D1 and D2 from the previous permitted level, while the other criteria pollutants remain unchanged and lower maximum potential daily emissions from this project for all pollutants. Table 19 below summarizes the change in emissions under the current permit to construct versus this proposed change in conditions to lower PM10 emissions.

Table 19 Potential-to-Emit 30-day averages (lbs/day)

	Turbine D1		Turbine D2		Aux Boiler D3	
	Current P/C	Proposed Change	Current P/C	Proposed Change	Current P/C	Proposed Change
NOx	18.84 [a]	18.84 [a]	18.84 [a]	18.84 [a]	1.32 [a]	1.32 [a]
SOx	45	45	45	45	1	1
VOC	126	126	126	126	7	7
CO	324	324	324	324	37	37
PM10	248	186	248	186	4	4

(a) NOx in lbs/hour per Rule 2005

Rule 1303 (a)(1)
This rule requires that the EO shall deny the Permit to Construct for any relocation or for any new or modified source which results in an emission increase of any nonattainment air contaminant, unless BACT is employed for the new or relocated source or for the actual modification to an existing source. The current permit to construct specifies BACT requirements for all applicable pollutants. These proposed change in conditions results in lower PM10 emissions and will not change the BACT requirements.

Rule 1303 (b)
This rule requires that the EO shall deny the Permit to Construct for any relocation or for any new or modified source which results in an emission increase of any nonattainment air contaminant at a facility, unless the following requirements are met: Modeling, Emission Offsets, Sensitive Zone Requirements, Facility Compliance, Major Polluting Facilities. These requirements were evaluated in the permit to construct issued 8-5-05 and determined to comply

with all requirements. These proposed change in conditions results in lower PM10 emissions and compliance with this subdivision is expected. Although not required, the applicant has provided AQMD with a revised modeling analysis due to the proposed change of conditions which has resulted in lower maximum modeled impacts than the results evaluated in AQMD's analysis approved for the permit to construct issued on 8-5-05. The results were reviewed by AQMD modeling staff and based upon this evaluation it was determined that the combined PM10 impact from the two turbines and the auxiliary boiler is 2.47 ug/m^3 (see memo dated May 11, 2006).

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). The change in conditions does not increase emissions of TACs. Therefore, the analysis performed under the Permit to Construct issued on 8-5-05 does not change. Therefore, no additional Rule 1401 analysis is required for this change in conditions.

RULE XVII- PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The South Coast Air Basin (SCAB) is in attainment for NOx and SO_2 emissions. Therefore, a PSD analysis for these pollutants must be conducted. PSD analysis for CO, PM10 and VOC are not required since the SCAB is not in attainment for these pollutants. The US EPA has the PSD jurisdiction. However, as of March 30, 2005, the AQMD has accepted the "Agreement for Limited Delegation Authority to Issue and Modify a Prevention of Significant Deterioration Permit Subject to 40 CFR 52.21" from US EPA for authority to issue an initial PSD permit and any subsequent administrative PSD permit for this project only.

On April 21, 2006, AQMD discussed the proposed change of conditions with Ms. Kathleen Stewart of EPA. Ms. Stewart conferred with EPA counsel and determined that this proposed change of condition modification is considered a PSD administrative permit action as defined in the March 30, 2005 PSD agreement between EPA and AQMD. For this change in condition, no increases in attainment pollutants are expected. Therefore, under Rule 1701 (b)(1) and (2), the BACT and PSD analysis requirements do not apply.

RULE 2005 – NSR FOR RECLAIM

Rule 2005 sets forth pre-construction review requirements for new facilities subject to the requirements of the RECLAIM program, for modifications to RECLAIM facilities, and for facilities which increase the allocation. Rule 2005 (c) sets forth requirements for existing RECLAIM facilities and modification to new RECLAIM facilities. The proposed change of conditions to lower PM10 emissions will not change the NSR analysis for RECLAIM pollutants.

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 commissioning period the NOx CEMS is not certified. The NOx emission factor is 68.26 lbs/MMscf which is calculated in Appendix A, Table A-8.

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 proposed change is considered a minor change to the Title V permit. A proposed permit revision will be prepared for this project. In accordance with Title V requirements, a copy of the proposed permit revision and analysis will be provided to the facility and to EPA for review. The final permit will be issued at the conclusion of the EPA 45-day review period as specified in Rule 3005(c)(2)(B)(ii).

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)
The combined cycle facility requires CEQA certification by the California Energy Commission (CEC). The requirements of a CEQA analysis of the original power plant design are met under the CEC licensing procedure (01-AFC-17), which was approved on December 17, 2003. The applications submitted to AQMD on February 3, 2005 which substitutes the F-class turbines with the H-class units received a CEC approved amendment to the AFC on June 22, 2005. The 6 month extension to negotiate a MOU with the U.S. Forest Service did not require an additional amendment to the AFC. Ms. Connie Bruins of the CEC was notified in IEEC's April 20, 2006 IEEC's letter of their intentions for the change in conditions.

IEEC has completed AQMD Form 400-CEQA and based upon their responses and the scope of the changes in condition, it is the determination by AQMD CEQA staff that no CEQA documentation is required by AQMD staff. However, since the CEC is the lead agency for this project, CEC will make any final determination on their process and subsequent action for this modification.

RECOMMENDATION

Based on the above engineering evaluation the District has reached a determination that this facility is expected to achieve compliance with all applicable rules and regulations. The final Title V permit issuance is contingent upon EPA review and approval. It is therefore recommended that the AQMD 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

Note, only conditions which have been changed or added are shown in this section. Changes are denoted by ~~STIKETHROUGH~~ and <u>UNDERLINE</u> punctuations. All other conditions remain the same as evaluated in the previous applications.

<u>A63.1</u> The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
CO	9,728 LBS IN ANY 1 MONTH
PM10	~~7,440~~ <u>5580</u> LBS IN ANY 1 MONTH
VOC	3,769 LBS IN ANY 1 MONTH
SOx	1,362 LBS IN ANY 1 MONTH

The operator shall calculate the emission limit(s) by using monthly fuel use data and the following emission factors: PM10 ~~3.91~~ <u>2.93</u> lbs/MMscf, SOx 0.71 lbs/MMscf.

The operator shall calculate the emission limit(s) by using monthly fuel use data and the following emission factors: VOC 1.79 lbs/MMscf for normal operations, VOC 12.29 lbs/MMscf for startups.

The operator shall calculate the emission limit(s) for CO, during the commissioning period, using fuel consumption data and the following emission factor: 22.19 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: 4.48 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]

D29.1 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
VOC 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 combined gas turbine 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.

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

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. 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 when this equipment is operating at loads of 100, 75, and 50 (50 percent or the minimum compliant load achieved) percent of maximum load for the NOx, CO, VOC, and ammonia tests. The PM test shall be conducted when this equipment is operating at 100 percent of maximum load. <u>All testing for this equipment shall be conducted in TRIPLICATE.</u>

[Rule 1303 – BACT, Rule 1303 – Offsets, Rule 2005 – BACT, Rule 2005 - Offsets, Rule 1401, Rule 1703 – PSD]

[Devices subject to this condition: D1, D2]

<u>D29.2</u> 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
VOC 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 when the gas turbine is operating at 100 percent of maximum heat input. <u>Testing for this equipment shall be conducted in TRIPLICATE.</u>

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

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. 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 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]

<u>E193.6 The operator shall restrict operation of this equipment according to the following requirements:</u>

<u>The calendar daily cumulative operating hrs for both gas turbines (D1 and D2) and aux boiler (D3) shall not exceed 60 hrs per day. The operating hrs shall be recorded and maintained using an automated data acquisition system. The operating hrs shall be determined from the RECLAIM certified NOx CEMS accurate to the nearest 15-min operating period.</u>

<u>The operator records shall maintain daily records summarizing daily operating hours of each of the following equipment – gas turbine D1, gas turbine D2, and auxiliary boiler D3, for at least 5 yrs and shall be made available to AQMD upon request.</u>

<u>[Rule 1303]</u>
<u>[Devices subject to this condition: D1, D2, D3]</u>

APPENDIX A

EMISSION – GAS TURBINE

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

CO = 3.0 ppmv, 1-hour average, dry at 15% O_2;
2.0 ppmv, 30-day average, dry at 15% O_2, for offset determination purposes
NOx = 2.0 ppmv, 1-hour average, dry at 15% O_2
2.0 ppmv, annual average, dry at 15% O_2, for offset determination purposes
VOC = 2.0 ppmv, 1-hour average, dry at 15% O_2
1.4 ppmv, 30-day average, dry at 15% O_2, for offset determination purposes
SOx = 0.25 gr/100 scf, sulfur content of natural gas
PM10 = exclusive use of natural gas. Emission reporting is based on 7.5 lbs/hr which is equivalent to 0.00288 lb/MMBtu.

Emission factors during startups 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.3-8 and Table K.3-9 of the application for calculation of 30-day averaged emissions and annual NOx emissions:

CO = 50 lb/hr. NOx = 125 lb/hr
VOC = 16 lb/hr, SOx = 1.83 lb/hr
PM10 = 7.5 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:

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

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 1.1676 shall be used for emission calculations that require exhaust correct to 3% O_2 level.

Table A-1 Natural Gas Composition

Composition	Molecular Weight	Fraction %	Expansion Factor	Expansion Factor
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 OF NORMAL OPERATIONS

For NOx, CO and VOC the application has provided exhaust concentration limits in ppmv. Thus, emissions are calculated with the following formulas.

Volumetric emission = 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 = volumetric emission rate * density at standard conditions
= volumetric emission rate * molecular weight / standard specific volume

SOx emissions are determined by using the fuel sulfur concentration (0.25 grain per 100 scf) and the following equation.

Mass emission rate = fuel sulfur mass concentration * fuel usage * 64/32
The ratio of 64/32 reflects the molecular weight (MW) ratio between SO_2 and sulfur.

The application provides a PM10 mass emission factor of 7.5 lbs/hr. This rate is equivalent to an emission factor of 0.00288 lbs/MMBtu and it is much less than the 0.0066 lbs/MMBtu emission factor listed in the AP42. The applicant has analyzed PM10 emission data of many existing combined cycle gas turbines. In addition, new source test data from an identical H-class turbine (50 htz vs 60 htz) located in Baglan Wales has demonstrated PM10 emissions rates equivalent to 4.5 lbs/hour for a comparable 7H unit. IEEC and AQMD believe the 7.5 lbs/hr emission factor is an appropriate estimate.

Several important constants and conversion factors are:

P = 14.7 PSIA, T = 288 K at the standard conditions

1 lb-mole ideal gas = 379 scf at the standard conditions (standard specific volume)

Emissions of 1-hour average, 30-day average, and yearly average are calculated in the next three tables. The results are generally in agreement with the applicant determined results. For example, the 1-hour average NOx emissions factor is 18.84 lbs/hr while the applicant determined value is 18.83 lbs/hr. The 1-hour average CO emission factor is 17.20 lbs/hr while the applicant determined value is 17.19 lbs/hr.

Table A-2 One Turbine, 36 °F, 100% Load, 1-hour Average

Variables	NOx*	CO*	VOC*	SOx	PM10
Heat Input (MMBtu/hr)	2,597	2,597	2,597	2,597	2,597
Heating Value (Btu/scf)	1,014.6	1,014.6	1,014.6	1,014.6	1,014.6
Fuel Usage (MMscf/hr)	2.560	2.560	2.560	2.560	2.560
Expansion Factor	8.56	8.56	8.56	8.56	8.56
Correction Factor (15% O_2)	3.542	3.542	3.542	3.542	3.542
Exhaust Flow (15% O_2) DSCFM	1,293,582	1,293,582	1,293,582	1,293,582	1,293,582
Exhaust Flow (15% O_2) DSCFM*	1,294,895	1,294,895	1,294,895	1,294,895	1,294,895
Molecular Weight (MW)	46	28	16	64	/
Fuel Sulfur (GR/scf)	/	/	/	0.0025	/
Concentrations (PPMV)	2.0	3.0	2.0	/	/
Volumetric Emission (scf/hr)	155.23	232.84	155.23	/	/
Emission Rate (lbs/hr)	**18.84**	**17.20**	**6.55**	**1.83**	**7.5**
Emission Rate (lb/MMBtu)	0.0073	0.0066	0.0025	0.0007	0.00288
Emission Factor (lb/MMscf)	**7.36**	**6.72**	**2.56**	**0.71**	**2.93**

* Exhaust flow provided by the applicant as a reference

Table A-3 One Turbine, 36 °F, 100% Load, 30-Day Average

Variables	NOx	CO*	VOC	SOx	PM10
Heat Input (MMBtu/hr)	2,597	2,597	2,597	2,597	2,597
Heating Value (Btu/scf)	1,014.6	1,014.6	1,014.6	1,014.6	1,014.6
Fuel Usage (MMscf/hr)	2.560	2.560	2.560	2.560	2.560

Expansion Factor	8.56	8.56	8.56	8.56	8.56
Correction Factor (15% O_2)	3.542	3.542	3.542	3.542	3.542
Exhaust Flow (15% O_2) DSCFM	1,293,582	1,293,582	1,293,582	1,293,582	1,293,582
Exhaust Flow (15% O_2) DSCFM*	1,294,895	1,294,895	1,294,895	1,294,895	1,294,895
Molecular Weight (MW)	46	28	16	64	/
Fuel Sulfur (GR/scf)	/	/	/	0.0025	/
Concentrations (PPMV)	2.0	2.0	1.4	/	/
Volumetric Emission (scf/hr)	155.23	155.23	108.66	/	/
Emission Rate (lbs/hr)	**18.84**	**11.47**	**4.59**	**1.83**	**7.5**
Emission Rate (lb/MMBtu)	0.0073	0.0044	0.0018	0.0007	0.00288
Emission Factor (lb/MMscf)	**7.36**	**4.48**	**1.79**	**0.71**	**2.93**

* Exhaust flow provided by the applicant as a reference.
* CO limit of 2.0 ppmv is a long-term average.

Table A-4 One Turbine, 63°F, 100% Load, Annual Average

Variables	NOx*	CO	VOC	SOx	PM10
Heat Input (MMBtu/hr)	2,503	2,503	2,503	2,503	2,503
Heating Value (Btu/scf)	1,014.6	1,014.6	1,014.6	1,014.6	1,014.6
Fuel Usage (MMscf/hr)	2.467	2.467	2.467	2.467	2.467
Expansion Factor	8.56	8.56	8.56	8.56	8.56
Correction Factor (15% O_2)	3.542	3.542	3.542	3.542	3.542
Exhaust Flow (15% O_2) DSCFM	1246760	1246760	1246760	1246760	1246760
Exhaust Flow (15% O_2) DSCFM*	1247904	1294895	1294895	1294895	1294895
Molecular Weight (MW)	46	28	16	64	/
Fuel Sulfur (GR/scf)	/	/	/	0.0025	/
Concentrations (PPMV)	2.0	2.0	1.4	/	/
Volumetric Emission (scf/hr)	149.61	149.61	104.73	/	/
Emission Rate (lbs/hr)	**18.14***	**11.05**	**4.42**	**1.76**	**7.5**
Emission Rate (lb/MMBtu)	0.0073	0.0044	0.0018	0.0007	0.00300
Emission Factor (lb/MMscf)	**7.36**	**4.48**	**1.79**	**0.71**	**3.04**

* Exhaust flow provided by the applicant as a reference
* For determining annual NOx emissions the average heat input is used. The 18.14 lb/hr rate was provided by the applicant and it is in general agreement of the calculated factor of 18.16 lb/hr.

<u>EMISSIONS OF THE COMMISSIONING PERIOD</u>

<u>PROCESS DESCRIPTION – COMMISSIONING PERIOD</u>

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. For the

H series turbines, an extended commissioning period is anticipated since this will be the first installation of these turbines. More extensive testing will be completed on turbine #1 to document H machine performance. Commissioning for turbine #2 will require fewer hours. The commissioning period is anticipated to last approximately four months; however, extended equipment outages may delay this to as much as six months. Emissions during commissioning are expected to be the same under either a four month or a six month period, as the delays, if they occur, will be associated with unit outages which result in no additional emissions. Emissions during this period are typically high, and they need to be calculated separately. Emissions during commissioning will be reduced to the greatest extent possible and IEEC will perform preliminary tuning of the turbines as soon as possible. The following is the proposed commissioning schedule:

- No Load Tests – These tests will occur over approximately an 8 day period for each gas turbine.
- Aeromechanical Validation – These tests will occur over approximately a 21-day period for each gas turbine. The SCR and CO catalyst will become operational during this period.
- Aerothermal Validation – These tests will occur over approximately a 21-day period for gas turbine number 1 and a 9-day period for gas turbine number 2.
- Performance & Off Design Testing – These tests will occur over approximately a 28-day period for gas turbine number 1 and a 13-day period for gas turbine number 2.
- Final Combustion Testing – These tests will occur over approximately a 25-day period for gas turbine number 1 and a 2-day period for gas turbine number 2.
- Compliance Testing – These tests will occur over approximately a 7-day period for gas turbine number 1 and a 4-day period for gas turbine number 2. Emission estimates are based on an average that reflects start-ups, shutdowns and operations during the compliance testing period.

Table A-5 contains the emission factors and assumptions provided in the application for the commissioning period.

Table A-5 Commissioning Schedule Emission Factors

Process	NOx	CO	VOC	PM10	SOx
No Load	270 lbs/hr average	299 lbs/hr average	13 lbs/hr average	7.5 lb/hr	1.83 lb/hr
Aeromechanical	199 lbs/hr average	63 lbs/hr average	5 lbs/hr average	7.5 lb/hr	1.83 lb/hr
Aerothermal	152 lbs/hr (GT1) 173 lbs/hr (GT2) average	42 lbs/hr (GT1) 33 lbs/hr (GT2) average	4 lbs/hr (GT1) 3 lbs/hr (GT2) average	7.5 lb/hr	1.83 lb/hr

Performance and Off Design	122 lbs/hr (GT1) 147 lbs/hr (GT2) average	59 lbs/hr (GT1) 34 lbs/hr (GT2) average	5 lbs/hr (GT1); 4 lbs/hr (GT2) average	7.5 lb/hr	1.83 lb/hr
Final Combustion	197 lbs/hr (GT1) 181 lbs/hr (GT2) average	37 lbs/hr (GT1) 20 lbs/hr (GT2) average	3 lbs/hr average	7.5 lb/hr	1.83 lb/hr
Compliance	180 lbs/hr (GT1) 208 lbs/hr (GT2) average	43 lbs/hr (GT1) 36 lbs/hr (GT2) average	3 lbs/hr average	7.5 lb/hr	1.83 lb/hr

Table A-6 shows the emissions during each step of the commissioning period.

Table A-6 Emissions during the Commissioning Period

Operating Mode	**Total Emissions (lbs)**				
	NOx	CO	VOC	PM10	SOx
CTG/HRSG 1 – No Load	2,323	2,568	114	65	16
CTG/HRSG 2 – No Load	2,323	2,568	114	65	16
CTG/HRSG 1 – Aeromechanical	8,579	2,700	200	323	79
CTG/HRSG 2 – Aeromechanical	8,579	2,700	200	323	79
CTG/HRSG 1 – Aerothermal	8,468	2,338	206	419	102
CTG/HRSG 2 – Aerothermal	5,532	1,056	106	239	58
CTG/HRSG 1 – Performance, off design	14,364	6,912	555	885	216
CTG/HRSG 2 – Performance, off design	9,251	2,155	242	473	115
CTG/HRSG 1 – Final Combustion	16,766	3,146	277	640	156
CTG/HRSG 2 – Final Combustion	2,358	264	34	98	24
CTG/HRSG 1 – Compliance	4,070	824	76	173	42
CTG/HRSG 2 – Compliance	3,117	639	53	113	28
Total Emissions (Two Turbines)	85,729	27,871	2,176	3,814	931

Based on the data shown in Table A-6, the next table shows a breakdown of emissions from each turbine during the commissioning period.

Table A-7 Emissions of Each Turbine during Commissioning Period

	NOx	CO	VOC	PM10	SOx
Turbine 1	54,569	18,488	1,428	2,505	611
Turbine 2	31,160	9,383	748	1,309	320

Turbine 1 NOx emissions during its commissioning period: 54,569 lbs
Turbine 2 NOx emissions during its commissioning period: 31,160 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

The gas turbine manufacturer, GE, has indicated that the two turbines will operate for a total of 509 hours during the commissioning period.

Total Fuel Consumption = 2.467 MMscf/hr *509 hrs = 1,255.7 MMscf

Table A-8 Average Emission Factors during Commissioning Period, Both Turbines

Emissions	NOx	CO	VOC	PM10	SOx
Total Emissions (lbs)	85,729	27,871	2,176	3,814	931
Total Fuel (MMscf)	1,256	1,256	1,256	1,256	1,256
Emission Factors (lb/MMscf)	68.26	22.19	1.73	3.04	0.74

Thus, the average NOx emission factor during the commissioning period shall be 68.26 lb/hr per turbine. The CO emission factor is 22.19 lb/MMscf for one turbine. The CO emission factor will be used in Condition 63-1.

30-DAY AVERAGE EMISSIONS

For the gas turbines the 30-day average emissions are calculated by assuming a 31-day period that includes 31 startup hours and 713 base load hours. Emission factors of Baseload have been calculated in Table A-3.

Table A-9 30-Day Average Emissions from One Gas Turbine

Pollutants	Startup Hours	Startup Emission Factor (lbs/hr)[1]	Baseload Hours	Emission Factor (lbs/hr)	PTE (lbs/day)	Monthly Emission (lbs/month)
NOx	31	125.0	713	18.84	577	17,308
CO	31	50.0	713	11.47	324	9,728
VOC	31	16.0	713	4.59	126	3,769
PM10	31	7.5	713	7.5	186	5,580
SOx	31	1.83	713	1.83	45	1,362
NH3[2]	31	--	713	17.41	414	12,413

1 Applicant provided data

2. NH3 emissions are calculated based on 5 ppmv, exhaust flow of 1,294,895 dscfm.

GAS TURBINES ANNUAL EMISSIONS

Annual emissions are calculated based on actual operating schedule. The facility has proposed three operating cases:

Case A Commercial operation with 30 cold starts and 150 hot starts
Case B Weekend shutdowns and daily starts
Case C 8,760 hours of 100% base load

The following table shows NOx emissions of the three operating cases.

Table A-10 NOx Annual Emissions from the Gas Turbines

	Case A	Case B	Case C
Number of hot starts per year	150	208	0
Duration of hot start (hrs/start)	1	1	1
Hours of hot start per year (hrs/year)	150	208	0
Number of cold starts per year	30	52	0
Duration of cold start (hrs/start)	6	6	6
Hours of cold start per year (hrs/year)	180	312	0
Duration gas turbine offline prior to hot start (hrs)	2	2	2
Offline hours per year due to hot starts (hrs/year)	300	416	0
Duration gas turbine offline prior to cold start (hrs)	72	60	72
Offline hours per year due to cold starts (hrs/year)	2,160	3,120	0
Hours baseline operation per year (hrs/year)	5,970	4,704	8,760
Baseline NOx concentration (ppmvd @ 15% 02)	2.0	2.0	2.0
NOx emission rate during baseline operation (lbs/hr)	18.14	18.14	18.14
NOx emission rate during starts (lbs/hr)	125	125	125
Annual NOx emissions hot starts (lbs/yr/turbine)	18,750	26,000	0
Annual NOx emissions cold starts (lbs/yr/turbine)	22,500	39,000	0
Annual NOx emissions baseline operation (lbs/yr/turbine)	108,296	85,331	158,943
Total NOx emissions per turbine (lbs/yr)	149,546	150,331	158,943
Total NOx emissions both turbines (lbs/yr)	299,092	300,662	317,886

Clearly the annual operating schedule of 100% base load operation produces the most emissions. This operation schedule is selected for calculation of annual emissions. Therefore, CO, VOC, PM10 and SOx annual emissions are also calculated by using the schedule of 8,760 hours 100% base line operation.

Table A-11 Annual Emissions from the Gas Turbines

	NOx	CO	VOC	SOx	PM10
Emission factor (lbs/hr)	**18.14**	**11.05**	**4.42**	**1.76**	**7.5**
Baseline Operation (hrs/yr)	8760	8760	8760	8760	8760
Emissions per turbine (lbs/yr)	158,943	96,825	38,730	15,436	65,700
Emissions both turbines (lbs/yr)	317,886	193,650	77,460	30,873	131,400

GAS TURBINES 1ST YEAR NO_X EMISSIONS

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. The facility is required to certify the CEMS at the conclusion of the commissioning period. Thus the interim period is the same as the commissioning period.

Since 100% base load operation is the worst polluting case the first year NOx emissions are then calculated by assuming the 4-month period commissioning period and the following 8-month period of 100% base load operation. The NOx emissions of each turbine during the period following commissioning are:

Turbine #1: 18.14 * 6,120 = 111,043 lbs
Turbine #2: 18.14 * 6,672 = 121,058 lbs

Therefore, the 1st year NOx emissions of the turbines are:

Turbine #1: 54,569 + 111,043 = 165,612 lbs
Turbine #2: 31,160 + 121,058 = 152,218 lbs

APPENDIX B

EMISSIONS FROM 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 as BACT and for determination of emission rates.

Table B-1 BACT Requirements for the Auxiliary Boiler

Emissions	BACT	Applicant Proposed	Most Stringent Level
NOx	7.0 ppmv at 3% O_2	7.0 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
VOC	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	Natural Gas 7.6 lb/MMscf(1)	Natural Gas 7.26 lb/MMscf	Natural Gas 7.26 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	5 ppmv	5 ppmv

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

All the proposed emission levels are guaranteed by the boiler manufacturer.

The boiler has a heat input of 152.12 MMBtu/hr. The higher heating value (HHV) of the natural gas is 1,014.6 Btu/scf.

The following equations are used to determine emissions of CO, NOx, VOC, and NH3.

Exhaust at 3% O_2= Fuel Usage (MMscf/hr) * Expansion Factor * 20.9/(20.9-3)
Emissions = Concentration (ppmv)*Exhaust at 3% O_2 (MMdscf/hr)/379 (scf/mole)*MW

The following equation is used to determine emissions of PM10 and SOx:

Emissions = Emission Rate (lb/MMscf) * Fuel (MMscf/hr)

Emissions are determined as shown in the following spreadsheet.

Table B-2 Emissions Calculations – Auxiliary Boiler

Variable	Unit	CO	NOx	PM10	VOC	SOx	NH3
Heat-input	MMBtu/hr	152.12	152.12	152.12	152.12	152.12	152.12
Heating Value	Btu/scf	1,014.6	1,014.6	1,014.6	1,014.6	1,014.6	1,014.6
Fuel Usage	MMscf/hr	0.1547	0.1547	0.1547	0.1547	0.1547	0.1547
Expansion factor		8.56	8.56	8.56	8.56	8.56	8.56
Exhaust flow at 3% O_2	MMscf/hr	1.547	1.547	1.547	1.547	1.547	1.547
Molecular Weight	lb/lb-mole	28	46		16	64	17
Emission Factors	lb/MMscf			7.26		0.71	
Emission concentration	ppmv	50	7		10		5
Emission Rate	lb/hr	5.71	1.32	1.12	0.65	0.11	0.35
Emission Factor	lb/MMscf	36.92	8.49	7.26	4.22	0.71	2.24

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

NOx = 8.49 lb/MMscf

The applicant has proposed a maximum 600 annual operation hours and 195 monthly operation hours. Therefore, the monthly maximum emissions are calculated based on 195 hours of operation. The yearly emissions are calculated based on 600 hours of operation.

Table B-3 30-Day Average Emissions

Pollutants	Baseload Hours	Emission Factor (lbs/hr)	PTE (lbs/day)	Monthly Emissions (lbs/month)	Yearly Emissions (lbs/year)
NOx	195	1.32	9	255	790
CO	195	5.71	37	1,113	3,426
VOC	195	0.65	4	127	390
PM10	195	1.12	7	218	672
SOx	195	0.11	1	21	66

The monthly maximum fuel usage is:

152.12 MMBtu/hr * 195 hours/month /1014.6 Btu/scf = 29.24 MMscf/mo

There will be a condition enforcing the monthly fuel usage to 29.24 MMscf/mo.

APPENDIX C

<u>NSPS CALCULATIONS</u>

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

For the GE H series gas turbine only heat rate based on the lower heating value is*:

Y= [2502.9*10^6 Btu/hr*0.90183]/[[405*10^6 Watt*0.67]*[1.055 kJ/Btu] = 8.78 kJ/Watt-hr

STD = 0.0075*(14.4/ 8.78) + 0 = 0.01230 % = 123.0 ppm

2). SOx limit

STD =150 ppmv @ 15% Oxygen dry basis

Note:
Because the 40 CFR 60 Subpart GG NOx limit is for the gas turbine only, the gas turbine only heat rate is calculated in this formula. The S107H combined cycle system cannot operate in simple cycle (gas turbine only) mode. For calculation purposes, an approximate factor of 0.67 gas turbine / total combined cycle system generating capacity was used in this formula. The 0.90183 factor is to convert from HHV to LHV.

APPENDIX D **<u>NATURAL GAS DATA</u>**

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

GAS COMPOSITION DATA
(from 06/00 to 09/00, grains/100 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
B1	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, B1= Blythe, B2 =Blythe, SN = South Needles