PERMIT TO CONSTRUCT

COMPANY NAME AND ADDRESS

Los Angeles Department of Water and Power
111 North Hope Street, Room 1050
Los Angeles, CA 90012

Contact: Mark Sedlacek (213) 367-3772

EQUIPMENT LOCATION

LA City, DWP Scattergood Generation Station
12700 Vista Del Mar
Playa Del Rey, CA 90293
SCAQMD ID #800075

EQUIPMENT DESCRIPTION

Section H of the Facility Permit, ID# 800075, Permit to Construct and Temporary Permit to Operate:

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
PROCESS 5 – INTERNAL COMBUSTION – POWER GENERATION					
TURBINE, UNIT NO. 4, GENERAL ELECTRIC, MODEL: 7FA.05, COMBINED CYCLE, NATURAL GAS, WITH DRY LOW-NOX BURNERS, 2,080.9 MMBTU/HR HHV @ 63 °F, WITH: A/N: 536783	D96	C100	NOx: Major Source	**NOx**: 2.0 PPMV (4) [RULE 2005, RULE 1703]; NOx: 29.54 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 9.82 LB/MMSCF INTERIM (1) [RULE 2012]; NOx: 15 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK];	A63.2, A99.4, A99.5, A195.5, A195.6, A195.7, A327.1, C1.8, C1.9, D29.1, D29.2,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
HEAT RECOVERY STEAM GENERATOR (HRSG) GENERATOR, SERVING UNIT NO. 4, 209.5 GROSS MW @ 63 °F STEAM TURBINE, NO. 5 GENERAL ELECTRIC, MODEL: A14, GENERATOR, SERVING UNIT NO. 5, 108.8 GROSS MW @ 63 °F.	B157			**CO**: 2.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2 PPMV (4) [RULE 1303-BACT]; **PM10**: 10.0 LB/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SO_2**: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	D29.3, D82.1, D82.2, E193.2, E193.3, E193.6, I298.1, K40.1, K67.1
OXIDATION CATALYST, BASF, CATALYST VOLUME: 1,200 FT^3; WITH: A/N: 536784	C100	D96, C101			
SELECTIVE CATALYTIC REDUCTION, CORMETECH, CATALYST VOLUME: 2,300 FT^3; WITH: AMMONIA INJECTION, AQUEOUS AMMONIA A/N: 536784	C101	C100, S103		NH_3: 5 PPMV (4) [RULE 1303-BACT]	D12.7, D12.8, D12.9, D29.3, E179.3, E179.4, E193.2, E193.5
STACK, SERVING UNIT 4, DIAMETER: 19 FT, HEIGHT: 213 FT, WITH: A/N: 536783	S103	C101			
TURBINE, UNIT NO. 6, NATURAL GAS, GENERAL ELECTRIC, MODEL: LMS100PA, INTERCOOLED, WITH WATER INJECTION, 904.1 MMBTU/HR HHV @ 63 °F,	D104	C106	NOx: Major Source	**NOx**: 2.5 PPMV (4) [RULE 2005, RULE 1703]; NOx: 98.06 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 15.9 LB/MMSCF INTERIM (1) [RULE 2012];NOx: 25	A63.3, A99.6, A99.7, A195.8, A195.9, A195.10, A327.1,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
WITH: A/N: 536803 GENERATOR, 103 GROSS MW @ 63 °F				PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2 PPMV (4) [RULE 1303-BACT]; **PM10**: 5.7 LB/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SO_2**: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	C1.11, C1.12, D29.1, D29.2, D82.1, D82.2, E193.2, E193.4, E193.6, E193.7, I298.2, K40.2, K67.5
OXIDATION CATALYST, BASF, MODEL: CAMET, CATALYST VOLUME: 160 FT^3; 80 MODULES, WITH: A/N: 536807	C106	D104, C107			
SELECTIVE CATALYTIC REDUCTION, CORMETECH, MODEL: CMHT-27, CATALYST TOTAL VOLUME: 1,211 FT^3; 12 MODULES, WITH: AMMONIA INJECTION AQUEOUS AMMONIA A/N: 536807	C107	C106, S109		NH3: 5 PPMV (4) [RULE 1303-BACT]	D12.7, D12.8, D12.9, D29.3, E179.3, E179.4, E193.2, E193.5
STACK, SERVING UNIT 6, DIAMETER: 13.5 FT, HEIGHT: 100 FT, WITH: A/N: 536803	S109	C107			

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
TURBINE, UNIT NO. 7, NATURAL GAS, GENERAL ELECTRIC, MODEL: LMS100PA, INTERCOOLED, WITH WATER INJECTION, 904.1 MMBTU/HR HHV @ 63 °F, WITH: A/N: 536805 GENERATOR, 103 GROSS MW @ 63 °F	D110	C112	NOx: Major Source	**NOx**: 2.5 PPMV (4) [RULE 2005, RULE 1703]; NOx: 98.06 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 15.9 LB/MMSCF INTERIM (1) [RULE 2012]; NOx: 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM10**: 5.7 LB/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SO_2**: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	A63.3, A99.6, A99.7, A195.8, A195.9, A195.10, A327.1, C1.11, C1.12, D29.1, D29.2, D82.1, D82.2, E193.2, E193.4, E193.6, E193.7, I298.3, K40.2, K67.5
OXIDATION CATALYST, BASF, MODEL: CAMET, CATALYST VOLUME: 160 FT^3; 80 MODULES, WITH: A/N: 536812	C112	D110, C113			
SELECTIVE CATALYTIC REDUCTION, CORMETECH, MODEL: CMHT-27, CATALYST TOTAL VOLUME: 1,211 FT^3; 12 MODULES, WITH: AMMONIA INJECTION AQUEOUS AMMONIA A/N: 536812	C113	C112, S115		NH3: 5 PPMV (4) [RULE 1303-BACT]	D12.7, D12.8, D12.9, D29.3, E179.3, E179.4, E193.2, E193.5

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
STACK, SERVING UNIT 7, DIAMETER: 13.5 FT, HEIGHT: 100 FT, WITH: A/N: 536805	S115	C113			
IC ENGINE, EMERGENCY, CATERPILLAR, DIESEL, MODEL 3516C DITA, 3,622 HP, LEAN BURN, TURBOCHARGED, WITH A JOHNSON MATTHEY CRT PARTICULATE FILTER, WITH PASSIVE REGENERATION, WITH: A/N: 536801 GENERATOR: 2.5 MW	D116		NOx: PROCESS UNIT	NOx: 3.7 G/BHP-HR (4) [RULE 2005, RULE 1703]; NOx: 170.5 LB/1000 GAL (1) [RULE 2012]; CO: 0.67 G/BHP-HR (4) [RULE 1703, RULE 1470]; VOC: 0.25 G/BHP-HR (4) [RULE 1303, RULE 1470] PM10: 0.007 G/BHP-HR (4) [RULE 1303,1470] SULFUR CONTENT: 15 PPM (5) [RULE 431.2]	D12.3, D12.10, E116.1, E193.2, E193.6, E193.7, E448.1, E448.3, E448.4 I298.4, K67.4
OIL/WATER SEPARATOR, #1, HIGHLAND, MODEL: HTC5000, VOL: 5000 GAL, FLOW RATE: 500 GPM, WITH: A/N: 536796	D118				
OIL/WATER SEPARATOR, #2, HIGHLAND, MODEL: HTC5000, VOL: 5000 GAL, FLOW RATE: 500 GPM, WITH: A/N: 536798	D119				
PROCESS 6 – EXTERNAL COMBUSTION – POWER GENERATION					
BOILER, UNIT NO. 1, NATURAL GAS, DIGESTER GAS, FUEL OIL NO. 6, COMBUSTION ENGINEERING, ~~1,200,000~~ 750,000 POUNDS OF STEAM PER HOUR, WITH OXYGEN CONTENT	D24		NOx: MAJOR SOURCE	**NOx**: 5.0 PPM (3) [RULE 2009]; **CO**: 500 PPMV(5) [RULE 1303]; 2000 PPMV (5A) [RULE 407]; **PM10**: 0.1 GRAINS/SCF	A99.1, A195.3, B61.2, C1.5, C1.7, D28.2, D29.4, D371.1,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
CONTROL, ~~1750~~ 1,134 MMBTU/HR WITH: A/N: ~~534825~~, 538662 GENERATOR, ~~185~~ 120.7 GROSS MW				(5) [RULE 409] SO2: 500 PPMV FUEL OIL (5) [RULE 407]; (9) [40CFR 72- Acid Rain Provisions]	E193.1, E193.8 K40.3

BACKGROUND

The Los Angeles Department of Water and Power (LADWP) operates the Scattergood Generation Station (SGS) located in Playa Del Rey. The SGS is a 55-acre electric power generating facility designed to provide electricity to the LADWP power distribution grid. The SGS has been in operation since 1958. The facility has three steam generating plants. Boilers #1 and #2 are each 185 MW and Boiler #3 is 460 MW. The total generating capacity is 830 MW. The boiler generators are capable of firing with both fuel oil and natural gas.

The LADWP signed a revised settlement agreement with the AQMD in 2010 that requires the LADWP to repower the Scattergood boiler generator #3 by December 31, 2015. The LADWP is to replace the boiler generator with clean and efficient power generators. In accordance with the Settlement Agreement the LADWP is now proposing to repower the 460 MW Boiler #3 with a new generation system that consists of one combined cycle combustion gas turbine (CTG) generator and two simple cycle combustion gas turbine (CTG) generators. The combined cycle generating system (CCGS) will consist of a General Electric 7FA combustion gas turbine and a General Electric A14 steam turbine. The gas turbine is rated at 209.5 MW and the steam turbine is rated at 108.8 MW. The total capacity of the CCGS is 318.3 MW. The two simple cycle gas turbines together are called the simple cycle generation system (SCGS). The SCGS includes two General Electric LMS100 combustion gas turbines. The GE LMS100 gas turbine generator is rated at 103 MW each. Thus, the SCGS has a generating capacity of 206 MW gross. The total capacity of the new power system is 524.3 MW.

The AQMD Rule 1304(a)(2) provides an offset and modeling exemption for utility boiler repower projects. The exemption is based on the gross megawatts of the existing utility boilers. It affords the exemption on the megawatts to megawatts basis. In order to take advantage of this exemption and based on the 524.3 MW capacity of the new system the LADWP needs to shutdown and/or de-rate existing boiler generators capacity by 524.3 MW. The LADWP decided to shutdown the 460 MW Boiler #3 and to de-rate Boiler #1 by 64.3 MW. As such the project has zero net megawatts increase.

Since the net increase in megawatts is less than 50 MW the LADWP contends that the project does not require review and approval from the California Energy Commission (CEC). In a letter from CEC to LADWP on August 24, 2012 CEC concluded that, based on the gross and net generating capacity, the repower project is non-jurisdictional to CEC.

The new power system will include air pollution control equipment. All of the gas turbines will operate exclusively with natural gas. Each combustion gas turbine will be connected to a CO oxidation catalyst and then a selective catalytic reduction (SCR) unit. The CO oxidation catalyst converts CO to CO_2, and reduces VOC emissions. The SCR injects aqueous ammonia at a given temperature window to react with the combustion exhaust, thus reducing NOx to nitrogen. The Scattergood facility has existing ammonia storage tanks and does not plan to build new ammonia storage tanks. Each CTG will also include a weatherproof, acoustic (i.e., sound-dampening) enclosure with separate compartments for the turbine and generator.

As part of the new power generation system the LADWP will construct a standby emergency generator, a directly connected diesel fuel storage tank, a wet surface air cooler, and two oil water separators.

The new combined cycle GE 7FA turbine will be labeled as Unit 4. The steam turbine will be labeled as Unit 5. The two simple cycle GE turbines will be called as Units 6 and 7. In accordance with AQMD Rules 1303 and 1313, LADWP will take Boiler #3 out of service and surrender the permit within 90 calendar days after the initial startup of the new power generating system. In addition, LADWP will finish the Boiler #1 de-rate project within 90 day of the initial startup of the new power generating system.

The following table is a summary of the applications submitted by LADWP.

Table 1 Application Numbers

Applications	Descriptions	Fees
536791	Facility title V permit significant revision	$1,747.19
536783	Gas turbine generator Unit 4 – GE	$15,811.76
536803	Gas turbine generator Unit 6 – GE	$15,811.76
536805	Gas turbine generator Unit 7 – GE	$7,905.88
536801	Standby diesel IC engine generator	$2,123.92
536796	Waste oil/water separator #1	$3,359.43
536798	Waste oil/water separator #2	$1,679.72
536784	SCR and CO Catalyst for Gas Turbine Generator #4	$3,359.43

536807	SCR and CO Catalyst for Gas Turbine Generator #6	$3,359.43
536812	SCR and CO Catalyst for Gas Turbine Generator #7	$1,679.72
538662	Boiler generator #1 de-rate project	$21,725.19
538664	Title V/RECLAIM major permit revision	$1,747.19
Total fee, including 50% fee of expedite permit processing		$118,718.75

LADWP Scattergood Generation Station is a federal Title V and Acid Rain facility. It also participates in the NOx RECLAIM program (Cycle 1). The facility is currently complying with all federal, state, and local rules and regulations.

The applications were received by the AQMD on May 15, 2012. They were deemed complete on May 22, 2012. The applicant requested expedite permit processing of the applications, and paid the 50% additional fee per Rule 301(u).

PROCESS DESCRIPTION

1. COMBINED CYCLE GENERATING SYSTEM (CCGS)

The CCGS consists of one General Electric 7FA combined cycle gas turbine generator. As shown in the process flow diagram on the next page the GE 7FA has the combustion gas turbine (CTG) part and the steam turbine part. Each part is connected to a separate electric generator. Combustion air is supplied to the CTG through an inlet air filter and associated inlet air ductwork. Evaporative coolers are placed at the air inlet and are turned on during hot weather to improve cycle efficiency. The air goes through the compressor, and then joins the pre-heated and compressed natural gas supplied through the fuel compressor, in the combustor and starts the combustion process. The high-temperature, high-pressure gas mixture produced in the combustor expands through the turbine blades, driving the turbine and the electric generator #4. This part generates 209.5 MW of electric power at the ambient temperature of 63 °F.

The exhaust of the CTG goes into the Heat Recovery Steam Generator (HRSG). The exhaust heats the feed water in the front section of the HRSG and convert it into high pressure (HP) superheated steam. The HP steam is delivered to the HP section of the GE A14 steam turbine. Steam exiting from the HP section goes to the intermediate section of the HRSG to be heated again. It joins the HRSG's intermediate pressure (IP) steam and enters the steam turbine's IP section. Steam exiting the IP section goes to the last section of the HRSG to be heated one more time. It joins the HRSG's low pressure (LP) steam that enters the steam turbine's LP section. Steam leaving the LP section enters the air-cooled condenser and condenses into water. The condensed water will then join the HRSG's feed water system. The steam turbine generator generates 108.8 MW at the annual average temperature of 63 °F.

The specifications of the CCGS are provided in Table 2. The natural gas provided at the Scattergood Generating Station has a lower heating value of 916.4 Btu/scf and a higher heating value of 1,017 Btu/scf. The maximum natural gas consumption is 2,046 MMscf/hr at 63 °F. The heat input rate is 2,080.8 MMBtu/hr based on the higher heating value (HHV). The CCGS generates 318.3 MW of electric power at the annual average temperature of 63 °F. In addition to the high thermal cycle efficiency the CCGS incorporates GE's Rapid Start Process (RSP) technology. This technology allows the CTG to reach its base load quickly, reducing startup time and emissions. The RSP further improves the CCGS efficiency. The thermal efficiency of the CCGS is 56.2% based on the lower heating value (LHV). The total net heat rate is 6,073 Btu/kWh based on the LHV and at the ambient temperature of 63 °F.

Table 2 The CCGS Specifications

PARAMETERS	**SPECIFICATIONS**
CTG Make and Model	General Electric 7FA.05
Fuel Type	Pipeline Natural Gas
Maximum Fuel Consumption, Natural Gas	2.046 MMscf/hr @ 63°F
Maximum CTG Exhaust Flow	4,079,000 lbs/hr @ 63°F
Maximum Stack Exhaust Flow	1,157,900 ACFM @ 63°F
Combustion Turbine Heat Input	1,875.1 MMBtu/hr @ 63°F (LHV) 2,080.8 MMBtu/hr @ 63°F (HHV)
Maximum CTG Output	209.5 MW@ 63°F
Gross CTG Heat Rate, LHV	8,951Btu/kWh@ 63°F
Gross CTG Heat Rate, HHV	9,923 Btu/kWh @ 63°F
NOX Combustion Control, Natural Gas	Dry Low NOx Combustor
Ammonia Injection Rate	150 lb/hr 29% aqueous NH_3 at full load @63°F
Post Combustion Control	SCR and CO Catalyst
Steam Turbine Make and Model	General Electric A14
Steam Turbine Output	108.8 MW @63°F
Net Plant Heat Rate, LHV	6,073 Btu/kWh @ 63°F
Net Plant Heat Rate, HHV	6,732 Btu/kWh @ 63°F
Net Plant Efficiency	56.2%@ 63°F (LHV)
Total Plant Gross Output	318.3 MW

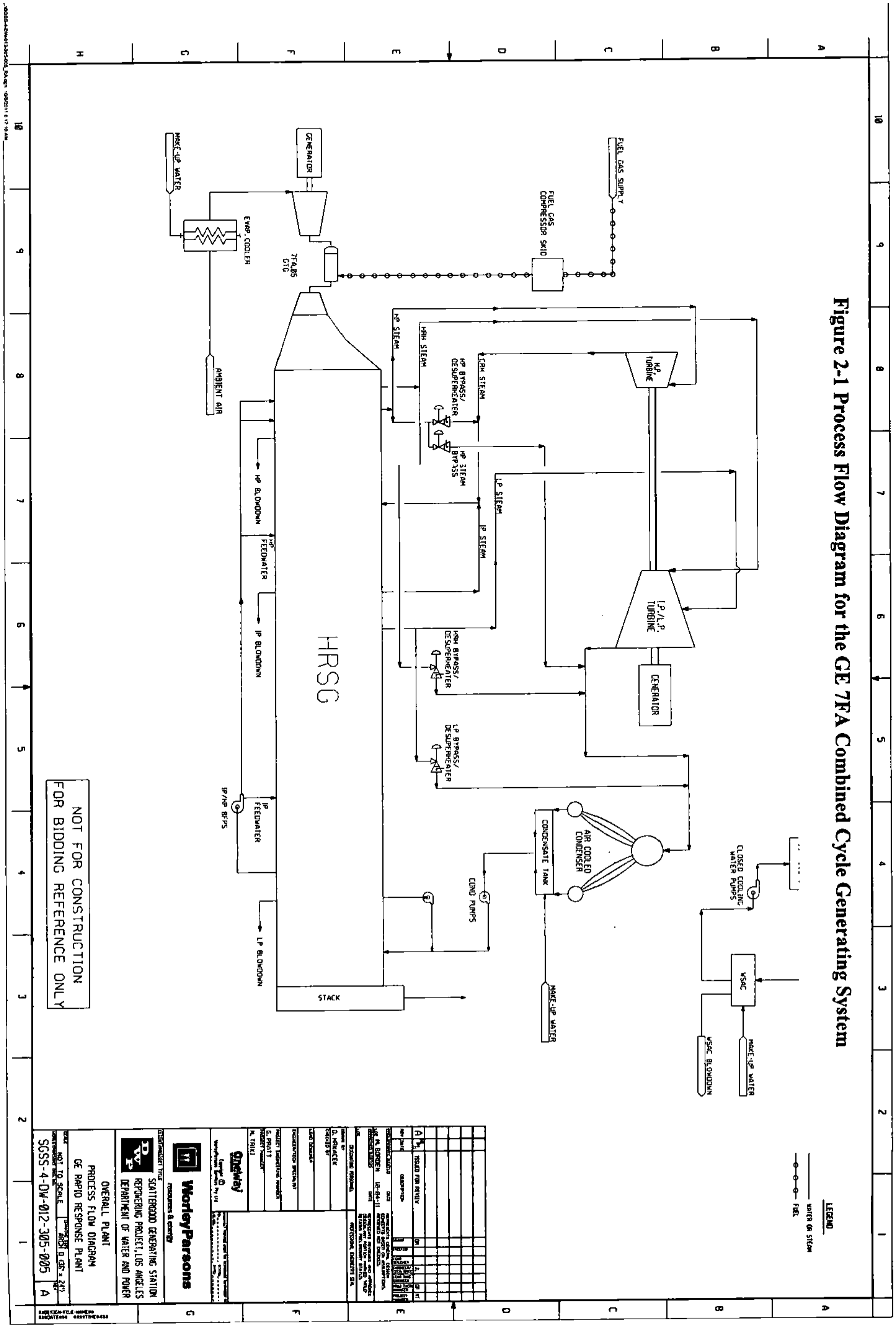
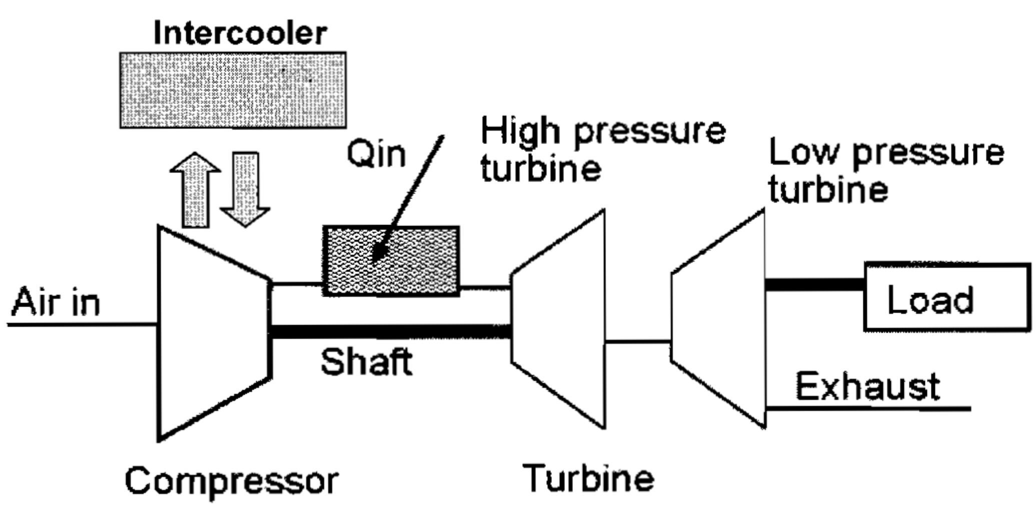


Figure 2-1 Process Flow Diagram for the GE 7FA Combined Cycle Generating System

2. SIMPLE CYCLE GENERATING SYSTEM (SCGS)

As shown in the process schematic on the next page the combustion air is supplied to the CTG through an inlet air filter and associated inlet air ductwork. Evaporative coolers are placed at the air inlet and are turned on during hot weather to improve cycle efficiency. Downstream of the air-cooling section, the air will be compressed in the low pressure compressor, sent to the intercooler and then back to the high pressure compressor. The intercooler lowers the air temperature and improves CTG performance. The intercooler is not used in the CCGS. The compressed air joins the pre-heated and compressed natural gas, supplied through the fuel compressor, in the combustor and starts the combustion process. The high-temperature, high-pressure gas mixture produced in the combustor expands through the turbine blades, driving the turbine, the electric generator, and the compressor. The exhaust and the intercooler will be cooled by a dry cooling tower system that will utilize fans to reject the heat to the atmosphere. A closed loop water system will be used to transfer the heat from the intercooler to the dry cooling towers.

LMS100 Gas Turbine with Intercooler



The specifications of the SCGS is provided in Table 3. The GE LMS100 gas turbine uses water injection for NOx control while the GE 7FA turbine of the CCGS uses a dry low NOx (DLN) combustor. The maximum natural gas consumption is 0.889 MMscf/hr at 63 °F. The heat input rate is 814.7 MMBtu/hr based on the LHV, and 904.1 MMBtu/hr based on the HHV. The SCGS generates 103 MW of electric power at the annual average temperature of 63 °F. The thermal efficiency of the CCGS is 41.9% based on the LHV. The SCGS heat rate is 8,147 Btu/kWh based on the LHV and at the ambient temperature of 63 °F.

Table 3 The SCGS Specifications

PARAMETERS	**SPECIFICATIONS**
CTG Manufacturer	General Electric
Model	LMS100PA
Fuel Type	Pipeline Natural Gas
Maximum Fuel Consumption, Natural Gas	0.889 MMscf/hr @ 63°F
Maximum CTG Exhaust Flow	1,733,000 lb/hr @ 63°F
Combustion Turbine Heat Input	814.7 MMBtu/hr @ 63°F (LHV) 904.1 MMBtu/hr @ 63°F (HHV)
Maximum CTG Output	103 MW@ 63°F
Gross CTG Heat Rate, LHV	7,912 Btu/kWh@ 63°F
Gross CTG Heat Rate, HHV	8,771 Btu/kWh @ 63°F
NO_X Combustion Control, Natural Gas	Water Injection
Ammonia Injection Rate	149 lb/hr at full load @63°F
Post Combustion Control	SCR and CO Catalyst
Maximum Stack Exhaust Flow	1,766,000 lb/hr @ 63°F
Net Plant Heat Rate, LHV	8,147 Btu/kWh @ 63°F
Net Plant Heat Rate, HHV	9,032 Btu/kWh @ 63°F
Net Plant Efficiency	41.9%@ 65°F (LHV)

3. AUXILIARY DEVICES

Selective Catalytic Reduction (SCR)

The SCR is a post-combustion control technology to reduce flue gas NOx emissions. At a given temperature window and with the presence of a specific catalyst ammonia reacts with nitride oxides of the combustion flue gas. The reaction converts NOx into nitrogen and lowers NOx emissions. A SCR system includes ammonia vaporization and injection equipment, a booster fan for the flue gas, an SCR reactor with catalyst, and instrumentation and control equipment. The new power system will use three SCR systems, one for each CTG. The facility will use the existing ammonia storage tanks to provide aqueous ammonia.

The SCR for the GE 7FA is designed to reduce the CTG exhaust NOx emissions from 9.0 ppmv to 2.0 ppmv, dry at 15% O_2. The SCR will be manufactured by Peerless or equivalent, with the catalyst modules manufactured by Cormetech or equivalent. The SCR catalyst will be operating within an optimal temperature window of approximately 575°F to 650°F to facilitate a heterogeneous reaction between NO_X and ammonia (NH_3). The catalyst in each SCR is expected to be vanadium based on a titanium support matrix. The life cycle of the SCR modules is expected to be three years. After that the SCR catalyst may be returned to the vendor for reprocessing. Additional details of the SCR system will be provided after the SCR vendor and specifications are finalized. The emission guarantee is 2.0 ppmvd NO_X dry at 15% O_2, with 5 ppmvd NH_3 slip at 15% O_2 at dry conditions.

Table 4 CCGS SCR Catalyst Data Summary

PARAMETERS	SPECIFICATIONS
Catalyst Manufacturer	Cormetech, Inc.
Catalyst Description	Titanium-Vanadium-Tungsten (Ti-V-W)
Catalyst Volume	2,300 ft^3
Space Velocity (typical)	48,000 hr^{-1}
Ammonia Injection Rate	150 lb/hr of 29% aqueous NH3 at full load
Ammonia Slip	5 ppmvd NH_3 at 15% O_2 1 hour average
Outlet NOx	2.0 ppmvd NOx at 15% O_2 1 hour average
Catalyst Life	Estimated to be 3 years
Exhaust Temperature	200 °F

The SCR for the GE LMS100 will reduce the CTG exhaust NOx emissions from 25 ppmv to 2.5 ppmv, dry at 15% O_2. The SCR will be manufactured by Express Integrated Technologies or equivalent, with the catalyst modules manufactured by Cormetech. The catalyst material will be vanadium based on a titanium support matrix. The catalyst model number is CMHT-27. The total catalyst volume is 1,211 cubic feet. There will be 12 layers of reactors, each measuring 2'-5" long by 10'-10" wide by 5'-6" tall. The SCR catalyst will be operating within an optimal temperature window of approximately 740°F to 800°F to facilitate a heterogeneous reaction between NO_X and ammonia (NH_3). The life cycle of the SCR modules is expected to be four years. After that the SCR catalyst may be returned to the vendor for reprocessing. Additional details of the SCR system will be provided after the SCR vendor and specifications are finalized. The emission guarantee is 2.5 ppmvd NO_X at 15% O_2, with 5 ppmvd NH_3 slip at 15% O_2 at dry conditions.

Table 5 SCGS SCR Data Summary

PARAMETERS	SPECIFICATIONS
Catalyst manufacturer	Cormetech, Inc.
Model number	CMHT-27
Catalyst description	Titanium-Vanadium-Tungsten (Ti-V-W)
Catalyst total volume	1,211 ft^3
Number of modules	12
Catalyst module dimension	2 ft 5⅜ in by 10 ft 10 in by 5 ft 6⅛ in
Ammonia injection rate	164 lb/hr of 29% aqueous NH3 at full load
Ammonia slip	5 ppmvd NH3 at 15% O_2 1 hour average
Outlet NOx	2.5 ppmvd NOx at 15% O_2 1 hour average
Catalyst life	Estimated to be 4 years
Exhaust temperature (typical)	766 °F

CO Oxidation Catalyst

The oxidation catalyst is a post-combustion control technology to reduce CO and VOC emissions in the hot exhaust of a combustion source. It is placed immediately downstream of the CTG and at the upstream of the SCR. Carbon monoxide of the combustion flue gas is oxidized to become carbon dioxide with the presence of the oxidation catalyst at a given temperature window. The new power generating system will use three oxidation catalysts, one for each CTG.

The oxidation catalyst for the GE 7FA gas turbine is designed so that the CCGS will comply with the CO BACT limit of 2.0 ppmv and VOC BACT limit of 2.0 ppmv, dry at 15% O_2. The CTG exhaust CO concentration is 4.4 ppmv, dry at 15% O_2, before the oxidation catalyst. The oxidation catalyst will be manufactured by BASF. The oxidation catalyst will be operating within an optimal temperature window of approximately 500°F to 700°F. The following table lists the expected operating parameters of the oxidation catalyst.

Table 6 The CCGS Oxidation Catalyst Summary

PARAMETER	SPECIFICATION
Manufacturer	BASF
Catalyst Type	Platinum, corrugated SS substrate
Catalyst Volume (typical)	1,200 ft^3
Outlet CO (typical)	2 ppmvd (1-hr average) at 15%O2
Outlet VOC (typical)	2 ppmvd (1-hr average) at 15% O2
Minimum Operating Temp (typical)	500 °F
Maximum Operating Temp (typical)	700 °F
Catalyst Life	3 years, expected

The oxidation catalyst for the GE LMS100 gas turbine is designed so that the SCGS will comply with the CO BACT limit of 4.0 ppmv and VOC BACT limit of 2.0 ppmv, dry at 15% O_2. The gas turbine exhaust has a CO concentration of 114 ppmv and VOC concentration of 2.4 ppmv before entering the oxidation catalyst. The oxidation catalyst will be manufactured by BASF. The catalyst model number is Camet. The catalyst reactors will be made of platinum group metals. The total catalyst volume will be 160 cubic feet. There will be 80 reactors, each measuring 3" long by 2' wide by 2'-1" tall. The catalyst type will be different from the CCGS because the SCGS exhaust temperature is higher. The oxidation catalyst will be operating within an optimal temperature window of approximately 500°F to 850°F. The following table lists the expected operating parameters of the oxidation catalyst.

Table 7 The SCGS Oxidation Catalyst Summary

PARAMETER	SPECIFICATION
Manufacturer	BASF
Catalyst model number	Camet
Catalyst Type	Platinum group metals
Catalyst Volume	160 ft^3
Number of modules	80
Catalyst module dimensions	3⅛ in by 2 ft by 2 ft 1½ in
Outlet CO (typical)	4 ppmvd (1-hr average) at 15%O2
Outlet VOC (typical)	2 ppmvd (1-hr average) at 15% O2

Minimum Operating Temp (typical)	500 °F
Maximum Operating Temp (typical)	850 °F
Catalyst Life	5 years, expected

Ammonia Injection Grid and Storage

Aqueous ammonia (ammonium hydroxide at 29 percent nominal concentration by weight) is currently used in the SCRs to reduce NO_X emissions for Boilers #1, #2, and #3 and will also be used for the new equipment, Units 4, 6, and 7. Ammonia will continue to be delivered to the site by truck and stored at the site's existing aqueous ammonia storage facility. Existing ammonia storage consists of three cylindrical aboveground storage tanks, with a total capacity of 90,000 gallons (30,000 gallons in each tank). Additional ammonia storage is not required for the new power generating system.

The vaporized ammonia will be diluted with air and injected into the gas turbine exhaust stream through nozzles for NO_X control. The amount of ammonia introduced into the system will vary depending upon NO_X reduction requirements, but will be approximately a 1.33:1 molar ratio of ammonia to NO_X. Expected maximum ammonia use is about 20 gallons per hour for the CCGS, and 19.9 gallons per hour for each of the SCGS gas turbines. The estimated annual ammonia usage is 175,200 gallons for the CCGS assuming the annual capacity factor of 100%. The estimated annual ammonia usage is 102,821 gallons per CTG for the SCGS assuming the annual capacity factor of 59%. The new power system total ammonia usage is expected to be 380,902 gallons per year.

Standby Generator

One diesel fuel standby power generator will be installed that would allow the gas turbines to have the black start capability, shut down safely and maintain critical systems during emergencies. The power rating of the standby power generator will be 3,622 brake horsepower. The engine will drive a 2.5 MW electric generator. A Johnson Matthey CRT diesel particulate filter (DPF) will be installed to minimize diesel particulate emissions. The standby generator will be tested for one hour every month. The specifications of this engine are provided in the Table 8.

Table 8 Emergency Generator Specifications

PARAMETER	SPECIFICATIONS
Manufacturer	Caterpillar
Model No.	3516C DITA
Rated Power	3,622 bhp (2,500 kW) at 1,800 rpm
Engine Design	Lean Burn, 4 stroke, water-cooled
Rated Fuel Consumption	173.3 gallons per hour
Number of Cylinders	16
Expected Hours of Operation	12 hr/yr (emission calculations are performed for 50 hrs/yr)
Type of Fuel	No. 2 Diesel, 15 ppmw sulfur content by weight
Stack Temperature	921.9 ºF
Stack Flow	19,048.7 ACFM
Stack Height	18 ft
Stack Diameter	20-inch
Aspiration	Turbocharged and aftercooled
Emission Control	Johnson Matthey CRT Diesel Particulate Filter

Based on the emission characteristics provided in the next table this diesel engine exceeds EPA Tier II emission standards. The DPF is installed so that the unit will meet the federal LAER requirement. The emission profile of the engine is provided in the next table.

Table 9 Standby Generator Emissions Specifications

PARAMETER	SPECIFICATIONS (gram/bhp-hr)
NOx	3.7
CO	0.67
Hydrocarbon	0.25
PM10	0.007 [with PM control efficiency of 90%: 0.07 g/bhp-hr x (1-0.9)]
SOx	0.2158 lb/1,000 gallons

A 2,800-gallon diesel storage tank will be constructed and directly piped to the standby generator. The diesel storage tank will not require an AQMD permit according to AQMD Rule 219(m)(15).

Oil Water Separator

Two new oil water separators (OWS) will be installed to serve the new power system. The OWS will collect potentially oily wastewater from equipment area wash downs and the HRSG feed water pump skid. The only potential oil contaminant is lubricating oil associated with the gas turbines and associated feed water pumps. Oil will be collected in the OWS and will be removed by vacuum truck before the oil collection section reaches its capacity. The proposed OWS will be Highland, model HT5000. Each will have a capacity of 5,000 gallons and handle a maximum flow rate of 500 gallons per minute.

Table 10 Oil/Water Separator Information

PARAMETER	SPECIFICATIONS
Make and Model	Highland Model HT 5000
Capacity	Separator: 5,000 gallons Spill Capacity: 1,000 gallons
Maximum Flow Rate	500 GPM
Dimensions	6-ft 0-in diameter by 23-ft 10-in long
Expected Flow Rates	Normally No Flow
Vapor Pressure of Oil	<0.01 mm Hg at 20°F
Oil Concentration in Wastewater	0-10%
Performance	10 ppm or less free oil effluent

Wet Surface Air Cooler (WSAC)

The new power generating system will use a 6-cell wet surface air cooler, i.e., cooling tower, to manage the excess heat from the auxiliary cooling system of the CCGS. The WSAC does not use ocean water for once through cooling (OTC). It is a closed-cycle wet cooling that is identified by the California Water Board as the best technology available. The hot auxiliary cooling water enters the WSAC tube bundle that is cooled both by a water spray and forced air current. The auxiliary cooling water does not come into contact with outside air or the water spray. The water sprayed onto the hot tube bundle is vaporized, transferring heat from the tube bundle to the spray water and then to the ambient air. The system uses either potable water or the evaporative cooler blowdown as makeup water. The WSAC has a drift loss factor of about 0.0005%.

The WSAC does not require an AQMD permit because the toxic risk level defined in Rule 1401 is less in one in a million. The maximum individual cancer risk (MICR) to a residential receptor was estimated to be 0.34 in a million.

Stacks

The CTG and the SCR of the CCGS uses a 213-foot tall, 19-foot diameter stack. The base elevation for the stack is 37 feet.

Each CTG and SCR catalyst group of the SCGS will vent to a 100-foot tall, 13.5-foot diameter stack. The base elevation for the SCGS stacks is 104 feet.

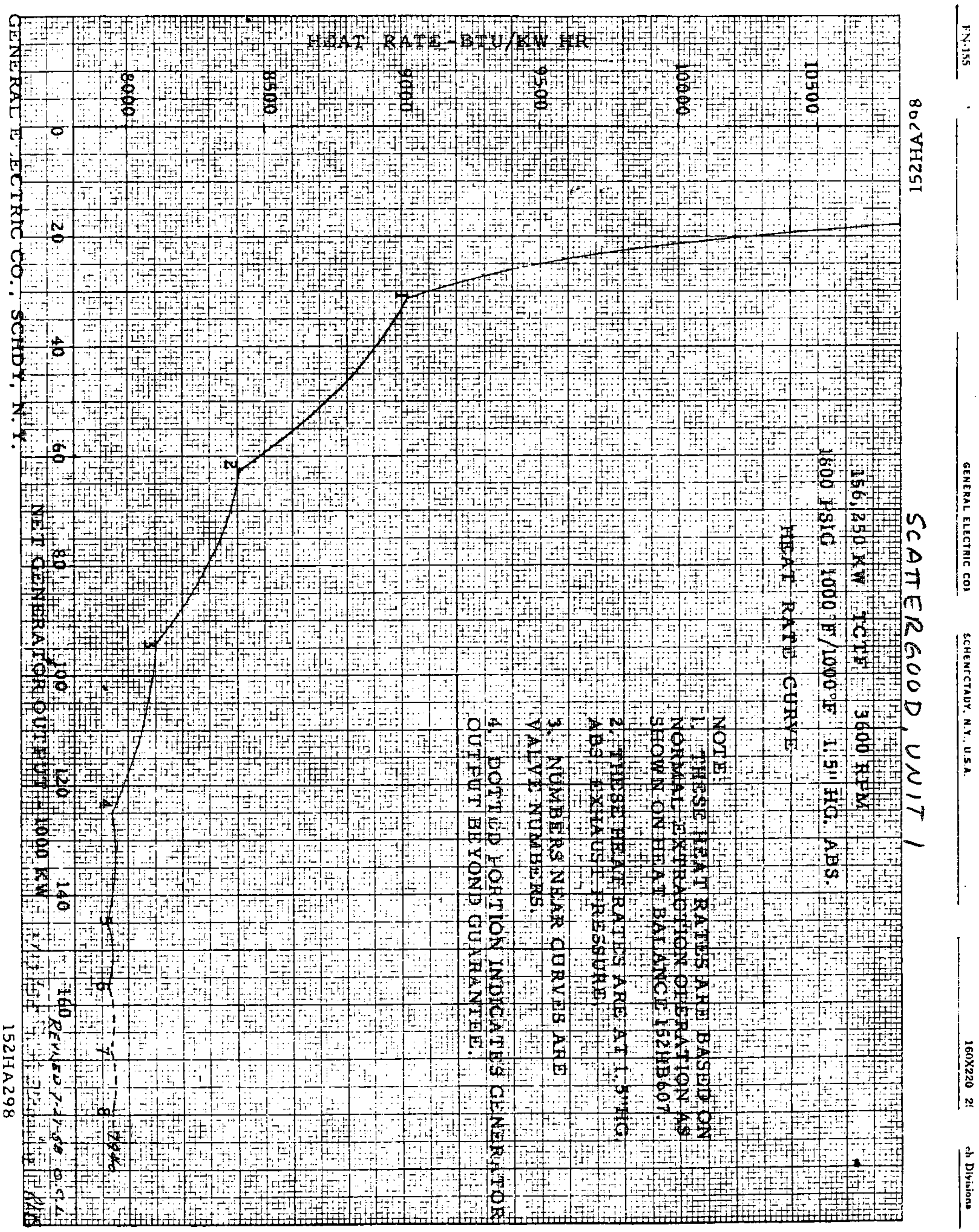
In addition to the stack, catalyst frames and ductwork will be required for the CCGS and the SCGS operation.

4. BOILER #1 DE-RATE

Boiler #1 currently in service at the Scattergood Generating Station was installed in the late 1950s. The boiler was manufactured by Combustion Engineering Company. It was designed to operate either with natural gas or with fuel oil. The option to burn digester gas was added later. The boiler is connected to a GE F2 steam turbine. The current specifications of the boiler are:

Steam rate:	1,200,000 lbs per hour.
Heat input:	1,750 MMBtu/hr, HHV
Power output:	185 MW gross, 179 MW net

The GE F2 steam turbine has eight (8) main steam control valves. The control valves regulate the amount of steam the steam turbine receives at the high pressure turbine section. The steam exiting the high pressure section is routed to the boiler reheater and goes back to the mid pressure section of the steam turbine. The amount of steam the turbine uses is directly proportional to its power generation. The operator controls the steam turbine power output by opening the control valves selectively. A chart containing the power curve provided by GE shows the correlation between the net power output and the number of valves opening. For example, the net power output is 124 MW with four valves open, 145 MW with five valve open, and 157 MW with six valves open. The chart shows that the generator will produce about 179 MW with all eight valves open. This is the maximum net power output.



HEAT RATE-BTU/KW HR
SCATERGOOD, UNIT 1
156,250 KW TCTF 3600 RPM
1600 PSIG 1000°F/1000°F 1.5" HG. ABS.
HEAT RATE CURVE
NOTE:
1. THESE HEAT RATES ARE BASED ON NORMAL EXTRACTION OPERATION AS SHOWN ON HEAT BALANCE 152HB607
2. THESE HEAT RATES ARE AT 1.5" HG ABS EXHAUST PRESSURE
3. NUMBERS NEAR CURVE ARE VALVE NUMBERS.
4. DOTTED PORTION INDICATES GENERATOR OUTPUT BEYOND GUARANTEE.
NET GENERATOR OUTPUT-1000 KW
GENERAL ELECTRIC CO., SCHDY, N.Y.
152HA298

In order to de-rate the boiler by 64.3 megawatts the facility will disable permanently control valves #5-8. The control valve actuating levers are driven by a camshaft assembly. By modifying the cam lobe profile the valve actuator travel can be altered. If the cam lobe is completely removed the corresponding control valve will not be activated and will remain closed. The facility will machine off the cam lobs for values #5-8. After control valves #5-8 are permanently closed the boiler's maximum power output is expected to drop to 128 MW gross, 124 MW net. This will reduce the power output by 57 MW approximately.

The further de-rate to 64.3 MW will require an additional 7.3 MW of power reduction. LADWP plans to alter the cam lobe profile of control valve #4, but not remove it entirely. The new cam lobe profile will reduce the opening of control valve #4. It is expected that a new cam lobe profile will be found through trial and error.

After the de-rate the boiler will have the following specifications:

Steam rate:	750,000 lbs per hour.
Heat input:	1,134 MMBtu/hr, HHV
Power output:	120.7 MW gross, 117 MW net

LADWP considers this de-rate approach is the most economical and efficient method. The heat rate of the boiler will not deteriorate because of the project.

Once the de-rate project is complete the boiler will be subject to the new heat input limit of 1,134 MMBtu/hr, and the generating capacity limit of 120.7 gross megawatts. A permit condition will be added to enforce the condition.

After the de-rate project is completed LADWP expects continued compliance with the current NOx and CO limits. The existing NOx and CO CEMS will continuously monitor the concentrations to ensure compliance. Compliance with the PM10 limit is also expected. However, a source test will be required to demonstrate compliance. The source test shall be conducted with gaseous fuel only.

COMPLIANCE HISTORY

A review of the facility's compliance history in the last five years shows the following violations of permit conditions:

- Notice of Violation (NOV) #P55502 was issued on April 10, 2009 for failure to correctly compute the15-minute NOx emission values for RECLAIM major sources. The NOV was closed out on April 23, 2009.

- Notice of Violation (NOV) #P55500 was issued on January 28, 2009 for failure to report quarterly mass emissions of NOx to AQMD for the process unit and Rule 219 equipment in the compliance years 2006 and 2007. The NOV was closed out on August 6, 2009.
- Notice of Violation (NOV) #P42944 was issued on September 24, 2008 for failure to submit the quarterly emission report in the 3rd quarter of 2004, for failure to comply with Title V Permit section K Condition #22, and for failure to comply with facility permit condition B61.2. The NOV was closed out on August 6, 2009.
- Notice of Violation (NOV) #P47784 was issued on September 7, 2007 for failure to conduct the visible emissions inspection required per permit condition D381.2 and for failure to conduct the semi-annual visible emissions inspections as required per permit condition D323.1. The NOV was closed out on February 5, 2008.

EMISSIONS

NEW POWER GENERATING SYSTEM

Emissions of criteria pollutants, hazardous air pollutants, and greenhouse gas pollutants from the new power generating system are calculated in the Appendices. A summary is provided below.

Criteria Pollutant Emissions

Detailed emissions calculation are included in the Appendices A, B and C. The potential to emit, the daily maximum emissions, the monthly total emissions, and the annual emissions are shown in the next four tables.

Table 11 Criteria Pollutants Potential to Emit – Monthly Average Emissions

	NOx	CO	VOC	PM10	SOx
Unit 4 – GE 7FA(1) (lb/day)	825	14,367	425	246	29
Unit 6 – GE LMS100(2) (lb/day)	430	688	65	143	13
Unit 7 – GE LMS100(2) (lb/day)	430	688	65	143	13
Standby Generator(3) (lb/day)	4.1	0.7	0.3	0.0	0.0

(1) Page 97, Table A-15, Appendix A
(2) Page 108, Table B-13, Appendix B
(3) Page 110, Table C-1, Appendix C

Table 12 Maximum Daily Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Unit 4 – GE 7FA(1) (lb/day)	501	993	151	244	29	340
Unit 6 – GE LMS100(2) (lb/day)	271	218	55	139	12	147
Unit 7 – GE LMS100(2) (lb/day)	271	218	55	139	12	147
Standby Generator(3) (lb/day)	30	5	2.0	0	0	0
New Equipment Total(lb/day)	1,073	1,434	263	522	53	634
New Equipment Total(ton/day)	0.54	0.72	0.13	0.26	0.03	0.32

(1) Page 93, Table A-8, Appendix A
(2) Page 104, Table B-7, Appendix B
(3) Page 110, Table C-1, Appendix C

Table 13 Monthly Total Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Unit 4 – GE 7FA(1) (lb/month)	14,227	26,730	4,425	7,393	871	8,750
Unit 6 – GE LMS100(2) (lb/month)	8,408	6,760	1,692	4,296	384	4,107
Unit 7 – GE LMS100(2) (lb/month)	8,408	6,760	1,692	4,296	384	4,107
Standby Generator(3)	124	22	8	0	0	0
New Equipment Total (lb/month)	31,167	40,272	7,817	15,985	1,639	16,964
New Equipment Total (ton/month)	15.58	20.14	3.91	7.99	0.82	8.48

(1) Page 96, Table A-9, Appendix A
(2) Page 107, Table B-8, Appendix B
(3) Page 111, Table C-1, Appendix C

Table 14 Annual Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Unit 4 – GE 7FA(1) (ton/year)	83.6	156.9	26.0	43.5	5.1	50.5
Unit 6 – GE LMS100(2) (ton/year)	34.6	25.3	5.8	15.1	1.3	13.2
Unit 7 – GE LMS100(2) (ton/year)	34.6	25.3	5.8	15.1	1.3	13.2
Standby Generator (ton/year)	0	0	0	0	0	0
New Equipment Total (ton/year)	152.8	207.5	37.6	73.7	7.7	76.9

(1) Page 93, Table A-8, Appendix A
(2) Page 103, Table B-7, Appendix B

Hazardous Air Pollutants (HAP) Emissions

Hazardous air pollutants emissions from the new power generating system are calculated in Appendix D. A summary is provided in the next table.

Table 15 Hazardous Air Pollutants Emissions per Year

	HAP (tons/year)
Unit 4 – GE 7FA.05	6.05
Unit 6 – GE LMS100	1.55
Unit 7 – GE LMS100	1.55
Standby Generator	0.02
Repower Project Total	9.17

Greenhouse Gas (GHG) Emissions

Greenhouse gas emissions from the new power generating system are calculated in Appendix E. The summary is provided in the next table.

Table 16 Greenhouse Gas Emissions from the New Equipment

	Daily Maximum CO2e (tons/day)	Monthly Total CO2e (tons/year)	Annual CO2e (tons/year)
Unit 4 – GE 7FA.05	2,953	87,147	1,026,128
Unit 6 – GE LMS100	1,283	38,561	261,985
Unit 7 – GE LMS100	1,283	38,561	261,985
Standby Generator	0	8	98
Circuit Breakers	0	5	55
Repower Project Total	5,519	164,282	1,550,251

BOILER #1 EMISSIONS

The current emissions rates of Boiler #1 were calculated in A/N430935. The calculations were based on heat input value of 1,750 MMBtu/hr. The fuel may be either natural gas, or a blend of natural gas and digester gas. Emissions from fuel oil operation are not calculated because it is used only as a backup fuel.

Because all the emissions limits remain the same the new emissions may be extrapolated using the factor of 1,134/1,750 based on the new heat input rate of 1,134 MMBtu/hr.

The pre-modification and post modification emissions are shown in the next table.

Table 17 Annual Greenhouse Gas Emissions

	NOx	CO	VOC	PM10	SOx	NH3
Pre modification (lbs/hr)	10.63	142.8	9.35	13.05	0.959	7.86
Post modification (lbs/hr)	6.89	92.53	6.06	8.46	0.62	5.09
Emissions Increase (lbs/hr)	-3.74	-50.27	-3.29	-4.59	-0.339	-2.77
30-day average (lbs/day)	165.4	2,220.7	145.4	203	14.9	122.2

There are emissions reductions as a result of the de-rate project.

RULES EVALUATION

<u>California Environmental Quality Act (CEQA)</u>

An Environmental Impact Report (EIR) has been prepared for this project. LADWP is the lead agency. The draft EIR was released on May 15, 2012. A copy of the draft was provided to AQMD for comments. AQMD provided written comments on July 2, 2012. AQMD commented on the issues of operational emissions, green house gas emissions, commissioning calculations, fugitive dusts, off road equipment, and overlapping construction phases. The comments were addressed by LADWP in the final EIR that was released in September 2012.

The final EIR was certified on September 18, 2012. The state clearinghouse number is 2011011079.

40CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines
Subpart GG applies to the stationary gas turbines that have a heat input of greater than 10.7 gigajoules per hour. However, gas turbines that are subject to the requirements of Subpart KKKK are exempted from this subpart. The new gas turbines are subject to Subpart KKKK, and are exempted from this subpart.

40CFR Part 60 Subpart IIII – Standards of Performance for Compression Ignition IC Engines
This subpart applies to the standby diesel generator.

Emergency compression ignition engines of model year 2007 or later with a displacement of < 30 liters per cylinder must to comply with the emission standards of §60.4202. The engine has a total displacement of 69 liters, a unit displacement of 4.3 liters/cylinder, and has a horsepower rating of 3,622 HP. Engines greater than 3,000 HP and manufactured after 2011 shall meet the performance standard of 40 CFR 89.112. According to 40 CFR 89.112 this engine, based on the power rating, will need to comply with the Tier 2 emissions limits. This engine meets the Tier 2 performance standards. Therefore, compliance is anticipated.

40CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Subpart KKKK applies to gas turbines that are installed after February 18, 2005 and have a heat input greater than 10.7 gigajoules per hour (10 MMBtu/hr). Both the GE 7FA and the GE LMS100 gas turbines will be subject to this regulation.

This regulation requires the gas turbines to meet NOx and SO_2 emission limits, which are determined based on the turbine's heat input rate and fuel type. NOx limits are provided in Table 1 of the subpart. The NOx limit is 25 ppmv for new natural gas fired turbines that are less than 850 MMBtu/hr, 15 ppmv if the heat input is greater than 850 MMBtu/hr. The SO_2 standard is 110 ng/J, or 0.9 lb/MWhr for units located in a continental area. The GE 7FA turbine will have a NOx limit of 2.0 ppmv, and a SO_2 limit equivalent to 0.006 lb/MWh (1.23 lb/210 MWh). The GE LMS100 gas turbines will have a NOx limit of 2.5 ppmv, and a SO_2 limit equivalent to 0.006 lb/MWhr (0.53 lb/103 MWhr). Compliance with the emission limits are expected.

In addition to the emission limits, Subpart KKKK requires continuous monitoring of the unit operation to ensure compliance. For units that use SCR and water injection to control NOx emissions, it is required to install a CEMS, and to conduct a performance test within 60 days of installation. The operator is required to measure fuel sulfur content unless it can demonstrate that the total sulfur in natural gas is less than 20 grains per 100 standard cubic feet (0.2 grain/scf). LADWP will install a NOx CEMS for each gas turbine in accordance with the SCAQMD Rule

2012. The installation of the CEMS satisfies the requirements for NOx monitoring. LADWP will prepare and issue all reports as required and maintain all appropriate records. The pipeline natural gas will have sulfur content below 16 ppmv, which is equivalent to 0.01 grains/scf, as it is subject to Rule 431.1. Thus, compliance with monitoring requirements are expected.

<u>40CFR Part 63 Subpart YYYY – NESHAP for Gas Turbines</u>
EPA has promulgated the National Emission Standards for Hazardous Air Pollutant (NESHAP) for various types of operation. NESHAP applies to facilities that are major sources of hazardous air pollutants. A major source facility is defined as having a single HAP emissions greater than 10 tons/year, or total HAP emissions greater than 25 tons/year. Based on the calculation of Appendix D.4, with the installation of the new power generating system the facility total HAP emissions will be approximately 9.5 tons per year. Thus, the Scattergood Generation Station is not a major source facility, and is exempt from the requirements of this subpart.

<u>40CFR Part 63 Subpart ZZZZ – NESHAP for Internal Combustion Engines</u>
This subpart applies to the standby diesel generator.

Because the Scattergood facility is not a NESHAP major source it is considered as an area source for the purposes of this regulation. New compression ignition IC engines greater than 500 HP located in an area source are required to meet the performance standards of 40 CFR Part 60 Subpart IIII. Because the standby generator will comply with 40 CFR Part 60 Subpart IIII compliance with this subpart is demonstrated.

<u>40CFR Part 64 – Compliance Assurance Monitoring (CAM)</u>
The CAM regulation applies to major stationary sources, which use control equipment to achieve a specified emission limit. The rule is intended to provide “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 be subject to a BACT limit for each of these pollutants. The standby generator and the oil water separators are not subject to his regulation.

NOx and CO BACT limits are met with added equipment, i.e., SCR and oxidation catalyst. Thus, this subpart rule applies to NOx and CO emissions. For each of the three gas turbines LADWP will install a continuous emission monitoring system (CEMS) for NOx and another one for CO. The NOx CEMS will be certified in accordance with Rule 2012 requirements and the CO CEMS will be certified in accordance with Rule 218 requirements. The CEMSs are equivalent to the Acid Rain CEMS and are considered as a continuous compliance determination method, which allows an exemption to the CAM rule per Part 64.2(b)(vi).

This subpart also applies to the VOC emissions because the VOC BACT limit is achieved with the help of the oxidation catalyst. The oxidation catalyst is effective when operating temperature is between 500 °F and 700 °F for the CCGS, and between 500 °F and 850 °F for the SCGS. The catalyst effectiveness is dependent upon the catalyst temperature. There will be a temperature gauge that monitors exhaust temperature continuously and records on the hourly basis. The exhaust temperature is required to be at least 500 °F. In addition the operator will conduct periodic source testing. Compliance is expected.

<u>40CFR Part 72 – Acid Rain</u>
The Scattergood facility currently has SO_2 allocations under the acid rain program, allocated to their Boilers 1 through 3. 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 purchase of SO_2 on the open market. The facility is also required to monitor SO_2 emissions through use of fuel gas meters and gas constituent analysis (use of emission factors is also acceptable in certain cases) or with the use of exhaust gas CEMS. The Scattergood facility will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with natural gas default sulfur data as allowed by the Acid Rain regulations (Appendix D to 40 CFR Part 75). If additional SO_2 credits are needed, LADWP will obtain the credits from the SO_2 trading market. Based on the above, compliance with this rule is expected.

<u>RULE 212 – Standards for Approving Permits</u>
The facility is not located within 1,000 feet of a school and the MICR for each gas turbine is less than 1 in a million. Thus, this project is not subject to the public notification requirements under Rule 212(c)(1) and (c)(3). However, this project is subject to Rule 212(c)(2) and Rule 212(g) public notice requirements because the daily maximum CO, NOx, PM10, and VOC 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 will be required to distribute the public notice to each address within ¼ mile radius of the project.

Subdivision (g) requires that the public notification and comment process include all applicable provisions of 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10. The minimum requirements specified in the above documents are included in paragraphs (g)(1), (g)(2), and (g)(3).

In accordance with paragraph (g)(1) of this rule, the District will make the following information available for public inspection at the El Segundo Public Library located at 111 West Mariposa Avenue, El Segundo and at the Los Angeles Public Library Playa Vista Branch located at 6,400 Playa Vista Drive, Los Angeles 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 will be published in a newspaper which serves the area that will be impacted by the project.

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

After the public notice is published, there will be a 30-day period for submittal of public comments.

RULE 218 – Continuous Emission Monitoring

This rule applies to the CO CEMS, which is required to verify CO emission levels from each gas turbine. The LADWP is required to submit an "Application for CEMS" for CO CEMS for each turbine and required to adhere to retention of records requirements and reporting requirements once approval to operate CO CEMS is granted. Compliance with this rule is expected.

RULE 401 – Visible Emissions

Visible emissions from the gas turbines are not expected since they will be firing exclusively with pipeline quality natural gas. The standby diesel generator will use only low sulfur diesel fuel. Visible emissions are not expected. Compliance with this rule is expected.

RULE 402 – Nuisance

Nuisance problems are not expected under normal operating conditions of the gas turbines and the auxiliary equipment. Compliance is anticipated.

RULE 407 – Liquid and Gaseous Air Contaminants

This rule limits SO_2 emissions to 500 ppm for equipment not subject to the gaseous fuel sulfur emission concentration limits of 431.1. It limits CO emissions to 2,000 ppm. Since gas turbines will be subject to Rule 431.1 and are expected to comply with Rule 431.1, the sulfur limit does not apply. Compliance with the CO limit of this rule is expected since the equipment is subject to the BACT CO emission limit of no more than 4 ppmv. Compliance with CO will also be verified through the CEMS data.

This rule does not apply to the stationary internal combustion engines such as the emergency diesel generators of this project.

RULE 409 – Combustion Contaminants
This rule applies to the gas turbines. However, it does not apply to the stationary internal combustion engines such as the standby diesel generators of this project. This rule limits combustion generated PM emissions to 0.1 gr/dscf at 12% CO_2.

The following operation data are used to determine PM loading for the CCGS:

PM = 10 lbs/hr
CO_2 = 4.0% in the exhaust
Exhaust flow = 58.54 MMscf/hr

Thus,

$$PM = \frac{10 * 7000 * 12 / 4.0}{58.54 * 10^6} = 0.004 \text{ grains/dscf}$$

The following operation data are used to determine PM loading for the SCGS:

PM = 5.7 lbs/hr
CO_2 = 4.0% in the exhaust
Exhaust flow = 23.28 MMscf/hr

Thus,

$$PM = \frac{5.7 * 7000 * 12 / 4.0}{23.28 * 10^6} = 0.005 \text{ grains/dscf}$$

Compliance is demonstrated for both the SCGS and the CCGS turbines..

RULE 431.1 – Sulfur Content of Gaseous Fuel
This rule requires that natural gas the sulfur content as H_2S shall be less than 16 ppmv. The natural gas fuel that LADWP will use is pipeline quality natural gas. Pipeline quality natural gas is certified to has sulfur content less than 1.0 gr per 100 scf, or about 16 ppmv. Compliance is expected.

RULE 431.2 – Sulfur Content of Liquid Fuel
Only the standby diesel generator is subject to this rule. The gas turbines will use natural gas exclusively. This rule prohibits use of liquid fuel with a sulfur concentration of greater than 15 ppmw. LADWP will use low sulfur diesel fuel that complies with the sulfur limit. 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. This rule limits combustion contaminants as PM to be either less than 11 lbs/hour, or less than 0.01 gr/dscf. For natural gas fired gas turbine engines almost all PM emissions are PM10 emissions. As calculated in Rule 409 evaluation PM10 emissions are 0.005 gr/dscf for the SCGS turbines, and 0.004 gr/dscf for the CCGS gas turbine. Since they both are less than 0.01 gr/dscf compliance is expected.

Regulation XIII – New Source Review for Non-RECLAIM Pollutants
New emissions sources are subject to the requirements of new source review (NSR). This regulation applies to non-attainment criteria pollutants that include VOC and PM10. Other criteria pollutants like CO and NO_2 are reviewed under PSD because they are attainment pollutants. NOx is reviewed under RECLAIM. NSR includes requirements of Best Available Control Technology (BACT), modeling analysis, and offset. NH_3 is subject to BACT requirement only.

1. Best Available Control Technology (BACT)

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 with the exception of the cost effectiveness clause.

CCGS

The BACT for the CCGS combined cycle gas turbines are determined by following the above BACT definitions:

VOC: A review of recently issued combined cycle gas turbines permits nationwide reveals that the most stringent VOC emission limit, for combined cycle gas turbines without a duct burner, is 2.0 ppmv based on 1-hour average, dry at 15% O_2. In 2011 the Lower Colorado River facility in Texas was permitted with a VOC BACT limit at 2.0 ppmv based on 3-hour average. The 2.0 ppmv limit based on 1-hour average is consistent with AQMD's BACT requirement for simple cycle gas turbine generators.

PM10: Use of natural gas with sulfur content as H_2S less than 1 grain per 100 scf.

The following is the AQMD determined BACT/LAER limits:

VOC: 2.0 ppmv, dry at 15% O_2, 1-hour average.

PM10: Use of natural gas with sulfur content as H_2S less than 1 grain per 100 scf.

LADWP has proposed to use the same emission limits for the GE 7FA combined cycle gas turbine. Thus, the BACT/LAER requirement is met. Compliance will be ensured through testing, monitoring and reporting requirements.

The SCR's BACT requirement is to meet the NH_3 slip limit of 5 ppmv. LADWP has proposed to limit the NH_3 slip limit to 5 ppmv. Compliance is expected.

<u>SCGS</u>

The BACT For the SCGS simple cycle gas turbines are determined by following the above BACT definitions:

VOC: A review of recently issued simple cycle gas turbines permits nationwide reveals that the most stringent VOC emission limit is 2.0 ppmv based on 1-hour average, dry at 15% O_2. The recently permitted simple cycle gas turbines at the LADWP Haynes Generating Station and at the city of Riverside are permitted at 2.0 ppmv, 1-hour average. The 2.0 ppmv limit is consistent with AQMD's BACT requirement for simple cycle gas turbine generators.

PM10: Use of natural gas with sulfur content as H_2S less than 1 gr per 100 scf.

The following is the AQMD determined BACT/LAER limits:

VOC: 2.0 ppmv, dry at 15% O_2, 1-hour average.

PM10: Use of natural gas with sulfur content as H_2S less than 1 grain per 100 scf.

LADWP has proposed to use the same emission limits for the GE LMS100 simple cycle gas turbines. Thus, the BACT/LAER requirement is met. Compliance will be ensured through testing, monitoring and reporting requirements.

The SCR's BACT requirement is to meet the NH_3 slip limit of 5 ppmv. LADWP has proposed to limit the NH_3 slip limit to 5 ppmv. Compliance is expected.

Standby Generator

AQMD's BACT determination for a standby generator is consistent with Rule 1470. An engine is required to meet emission performance standards, i.e., tier levels, based on its power ratings. The standby generator of this project is rated at 3,622 HP, and is required to meet Tier 2 emission standards. In addition, because the facility is a major source, the engine will be required to install a diesel particulate filter (DPF).

VOC: Comply with the Tier 2 limit for a diesel engine greater than 750 bhp
PM10: Use of CARB certified diesel, and use of a diesel particulate filter because of LAER

The next table shows the standby generator's emission limits and Tier 2 emission limits.

Table 18 Standby Generator Emissions Limits

	NMHC + NOx (g/bhp-hr)	CO (g/bhp-hr)	PM (g/bhp-hr)
This engine	3.95 (3.7+0.25)	0.67	0.07 before the DPF, 0.007 after the DPF
Tier 2 standards	4.8	2.6	0.15

Compliance is expected.

Oil/Water Separator

The oil/water separators and the diesel storage tank have emissions less than 0.5 lbs/day. They are exempted from the requirement of BACT.

2. Modeling Analysis

Modeling analysis is required for CO and PM10 emissions per Rule 1303(b). Modeling analysis for VOC is not required. Rule 1303 requires that through modeling, the applicant must substantiate that the project does not exceed the most stringent ambient air quality standard for attainment pollutants or cause a significant change in air quality concentration for non-attainment pollutants. The Scattergood Generation Station is located the area that is PM10 non-attainment, but CO attainment. Therefore, the CO emissions from the proposed project shall not cause a violation of the most stringent air quality standard and the PM10 emissions shall not be greater than the significant change threshold.

Maximum project impacts from CO and PM10 emissions were determined by using the AERMOD model, version 12060. The representative meteorological data used in the model are from the Los Angeles International Airport. Modeling analysis were performed for startup, shutdown, commissioning, normal operation, and diesel readiness tests. Although Rule 1303 requires modeling analysis on equipment by equipment basis the applicant elected to analyze the entire project as a whole emission group. This approach is more stringent than Rule 1303 specifies.

The standby generator is exempt from modeling analysis.

CO Emissions

A variety of operating scenarios of the three gas turbines are modeled to determine the worst air quality impact. The following operating conditions are identified to have the highest impact.

1-hour impact: The CCGS in commissioning phase 4 and the SCGS is commissioning phase 6.
8-hour impact: The CCGS in commissioning phase 4 and the SCGS is commissioning phase 6.

The next table shows the maximum impacts from the modeling results and the applicable CO emissions standards.

Table 19 New Source Review Modeling – CO Emissions

Pollutants	Averaging Time	LADWP Model Results (μg/m^3)	Background Concentrations (μg/m3)	Total Impact (μg/m3)	Most Stringent Air Quality Standard (μg/m3)
CO	1-hour	1,076	4,581	5,657	23,000
	8-hour	589	2,863	3,452	10,000

The projected ambient concentrations will be below the most stringent air quality standard. Compliance is demonstrated.

PM10 Emissions

A variety of operating scenarios of the three gas turbines are modeled to determine the worst air quality impact. The following operating conditions are identified to have the highest impact.

24-hour impact: The CCGS and the SCGS in normal operation with a load factor of 50%.
Annual impact: The CCGS and the SCGS in normal operation with a load factor of 100%.

The next table shows the maximum impacts from the modeling results and the applicable PM10 emissions standards.

Table 20 New Source Review Modeling – PM10 Emissions

Pollutants	Averaging Time	LADWP Model Results (μg/m^3)	Significant Change Threshold (μg/m3)	Significant (Yes/No)
PM10	24-hour	0.88	2.5	No
	Annual	0.26	1.0	No

Total PM10 emissions increase, both the 24-hour average and the annual average, are below the respective significant change thresholds.

LADWP submitted the air quality modeling analysis in May 2012 to the District for review. The District found the analysis acceptable for Rule 1303 requirements.

3. Offset

Rule 1303(b)(2) requires that all increases in emissions be offset unless exempt from offset requirements pursuant to Rule 1304.

Rule 1304(a)(2) - Electric Utility Steam Boiler Replacement states that if the electric utility boilers are replaced by the combined cycle gas turbines, intercooled, or other advanced gas turbines the project will be exempt from emission offsets unless there is a basin-wide electricity generation capacity increase on a per-utility basis. If there is an increase in basin-wide capacity, only the increased capacity must be offset. The GE 7FA gas turbine is a combined cycle gas turbine, and the two GE LMS100 gas turbines are simple cycle intercooled gas turbines. Replacing the utility boiler generators with these three gas turbines is allowed by Rule 1304(a)(2) and qualifies for the exemption.

The language of this exemption allows for offset and modeling exemptions on a MW to MW basis. The purpose was to facilitate the removal of older and less efficient boiler/steam turbine technology with cleaner gas turbine technology at the utilities. Since the advent of RECLAIM, the exemption was expanded to include modifications conducted for compliance with Reg. XX rules.

The CCGS has a combined power rating of 318.3 gross megawatts. The SCGS has a combined power rating of 206 gross megawatts. The total power generating capacity is 524.3 MW. The existing Boiler 3 is rated at 460 megawatts. To make up the difference of 64.3 megawatts LADWP has elected to de-rate the existing Boiler 1 by 64.3 megawatts. It has submitted an application A/N538662 for the proposed de-rate modification. The application is under AQMD review. If approved, the de-rate of Boiler 1 will provide the 64.3 megawatts reduction to offset the new power system increase. The net megawatts increase will be zero. The new power generating system qualifies for the Rule 1304(a)(2) exemption. The facility does not have to provide emission reduction credits for this project.

The standby generator is exempt from offset requirement. The two oil water separators have a combined VOC emissions of 0.07 lb/day. Offset for VOC is not required.

<u>RULE 1325 – Federal PM2.5 New Source Review Program</u>

This rule applies to major polluting facilities, major modifications to a major polluting facility, or any modifications to an existing facility that would constitute a major polluting facility in and of itself. A major polluting facility is defined as a facility which has actual emissions, or the potential to emit, greater than 100 tons per year. Based on the calculation of Appendix F.4 the Scattergood facility PM2.5 potential to emit from the existing equipment is 290.2 tons per year. Therefore, it is a major polluting facility and it is subject to this rule.

The requirements of this rule are:

- Use of LAER
- Offset PM2.5 emissions at the offset ratio of 1.1:1
- Certification of compliance of emission limits
- Conduct an alternative analysis of the project

The Scattergood repower project will use pipeline natural gas for the gas turbines. Use of natural gas is considered BACT and LAER for PM emissions. The equipment will be subject to PM10/PM2.5 emission limits. An alternative analysis under CEQA process is being performed as part of the Environmental Impact Report. The offset liability would be 232 lbs of PM2.5 per day, as calculated in Appendix F.2.

Rule 1325 allows the use of an actuals Plantwide Application Limitation (PAL) for an existing major polluting facility. PAL means an emission limitation expressed in tons per year as an enforceable limit. The actuals PAL is based on the baseline actual emissions, of all emissions units at the source, that emit or have the potential to emit the PAL pollutant. The PAL, once approved by the AQMD, is valid for a period of ten years.

The repower project will replace Boiler 3 and de-rate Boiler 1 by adding one combined cycle gas turbine and two simple cycle gas turbines. The total PM2.5 potential to emit increase from the new equipment is 73.6 tons per year. The shutdown of Boiler #3 and de-rate of Boiler #1 will reduce PM2.5 potential to emit by 190 tons per year. The repower project net PM2.5 emissions impact will be a net reduction of 116.4 tons per year, based on potential to emit. After the repower project the facility total PM2.5 potential to emit will be 173.8 tons per year (290.2-116.4), exceeding the 100 tons/year limit. The Scattergood facility will continue to be a major polluting facility. The detailed calculations are included in the Appendix F.1.

The LADWP will accept an actuals PAL of 100 tons per year of PM2.5 emissions for the Scattergood facility. Because the major source PM2.5 threshold is 100 tons per year and the significant PM2.5 emissions rate is 10 tons per year, the requirements of Rule 1325 will not apply to facilities if the facility emissions, including existing equipment and equipment currently proposed, will result in a potential to emit of less than 100 tons of PM2.5 per year.

In order to demonstrate compliance with the 100-ton facility wide PM2.5 emission limit the facility will use the following formula to calculate PM2.5 emissions.

$$PM_{2.5} = (FF_1*EF_1+ FF_2*EF_2+ FF_4*EF_4+ FF_6*EF_6+ FF_7*EF_7+ FF_{D1}*EF_{D1}+ F_{D2}*EF_{D2})/2000$$

Where

PM2.5 = PM2.5 emissions in tons per year

FF_1= fuel flow for Unit 1 in MMscf, Unit 1 is a boiler generator
FF_2= fuel flow for Unit 2 in MMscf, Unit 2 is a boiler generator
FF_4= fuel flow for Unit 4 in MMscf, Unit 4 is the GE 7FA.05 turbine generator
FF_6= fuel flow for Unit 6 in MMscf, Unit 6 is the GE LMS100PA turbine generator
FF_7= fuel flow for Unit 7 in MMscf, Unit 7 is the GE LMS100PA turbine generator
FF_{D1}= fuel flow for standby generator D19 in Mgal
FF_{D2} = fuel flow for standby generator D116 in Mgal

EF_1= emission factor for Unit 1 = 7.6 lb/MMscf
EF_2= emission factor for Unit 2 = 7.6 lb/MMscf
EF_4= emission factor for Unit 4 = 5.10 lb/MMscf
EF_6= emission factor for Unit 6 = 6.70 lb/MMscf

EF_7= emission factor for Unit 7 = 6.70 lb/MMscf
EF_{D1}= emission factor for D19 = 34.4 lb/Mgal
EF_{D2} = emission factor for D116 = 0.3 lb/Mgal

The emission factors are determined in Appendix F.2.

In the event that the facility total PM2.5 emissions exceed 100 tons per year, the facility must submit permit applications to modify the permit and provide offset. Offset requirements are calculated in Appendix F.1. Offsets are calculated by determining the net annual emissions increases from this proposed project. As calculated, the project net PM2.5 emission increase is 210.54 lbs/day. With the offset ratio of 1.1 to 1 LADWP will be required to provide 232 pounds per day of federally enforceable PM2.5 emission reduction credits.

RULE 1401 – New Source Review for Toxic Air Contaminants
This rule specifies limits for maximum individual cancer risk(MICR), cancer burden, and acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permits which emit toxic air contaminants (TAC).

Rule 1401 requirement levels are as follows:

MICR, without T-BACT:	≤ 1 in 1 million (1.0×10^{-6})
MICR, with T-BACT:	≤ 10 in 1 million (1.0×10^{-5})
Cancer Burden:	≤ 0.5
Maximum Chronic Hazard Index:	≤ 1.0
Maximum Acute Hazard Index:	≤ 1.0

Rule 1401 applies to new or modified permitted units unless those units are exempted by the provisions of Rule 1401(g). The standby generator is exempted from Rule 1401 per Rule 1401(g)(1)(F). The two oil water separators have minimal VOC emissions and negligible TAC emissions. They are expected to comply with the requirements of this rule.

LADWP performed a detailed health risk analysis using CARB's Hotspots Analysis Reporting Program (HARP) model for the CCGS and the SCGS gas turbines. The HARP model combines the EPA's AERMOD air dispersion model with a risk assessment model that is based on the AB2588 Air Toxics Hot Spots Program Risk Assessment Guidelines. The CCGS gas turbine is assumed to operate for 8,760 hours in a year at 100% load, and the SCGS turbines are assumed to operate for 5,168 hours in a year at 100% load. The modeling results are provided in the next table.

Table 21 Health Risk Assessment from Combustion Turbines

Units	MICR, Resident	MICR, Worker	Chronic Hazard Index	Acute Hazard Index
CCGS Turbine #4	0.13 in a million	0.02 in a million	0.003	0.004
SCGS Turbine #6	0.03 in a million	0.005 in a million	0.0006	0.002
SCGS Turbine #7	0.03 in a million	0.005 in a million	0.0006	0.002

Results of the analysis show that the highest estimated MICR is 0.13 in a million, which is below the Rule 1401 threshold limits of 1 in a million. The estimated acute hazard index is 0.004, less than the rule limit of 1.0. In addition, the chronic hazard index is 0.003, which is also less than the rule limit of 1.0. Thus, the CCGS and the SCGS gas turbines will be in compliance with Rule 1401.

The District has reviewed the Rule 1401 modeling analysis conducted by LADWP. The District considers the modeling approach and methodology are consistent with AQMD Rule 1401. The modeling results are acceptable.

<u>RULE 1401 – New Source Review for Toxic Air Contaminants – Cooling Towers</u>
The project will install a wet surface air cooler. This equipment will require an AQMD permit if the cancer risk exceeds 1 in a million. Otherwise, it is exempt from permitting requirement pursuant to Rule 219(d)(3).

A health risk analysis (HRA) is conducted using the same approach as the HRA for the gas turbines. The modeled results show the maximum individual cancer risk (MICR) is 0.34 in a million. The acute hazard index is 0.017 and the chronic hazard index is 0.057.

<u>Rule – 1470 Requirements for Stationary Diesel-Fueled Internal Combustion Engines</u>
This rule applies to the standby diesel fueled IC engine generator. Based on the horsepower rating and the proposed installation date the engine shall meet the EPA Tier 2 engine emission standards. This requirement is consistent with the 40 CFR Part 60 Subpart IIII NSPS requirements. The proposed Caterpillar engine meets or exceeds the Tier 2 emission standards based on the comparison presented in the Table 15.

The facility will use only diesel fuel that contains less than 15 ppmw sulfur. This requirement is consistent with Rule 431.2.

The engine will install a Johnson Matthey CRT particulate filter that reduces PM emissions by 90%. Based on the PM emission rate the engine is allowed 50 hours per year for maintenance and testing operations.

Regulation XVII – Prevention of Significant Deterioration – Criteria Pollutants

The AQMD and the EPA has entered an agreement on July 25, 2007 that AQMD is re-delegated a partial PSD authority. AQMD is authorized to issue new and modified PSD permits in accordance with AQMD's Regulation XVII. Since this is a partial delegation the facilities in the South Coast Air Basin (SCAB) may either apply directly to EPA for the PSD permit in accordance with the current requirements of 40CFR Part 52 Subpart 21, or apply to AQMD in accordance with the current requirements of Regulation XVII. The LADWP has chosen to apply to AQMD.

The SCAB is in attainment for NO_2, SO_2, and CO emissions. Therefore, this regulation applies to NO_2, SO_2, and CO emissions.

BACT applies to all projects that have emission increases. BACT requirements for NO_2, CO and SO_2 are evaluated in this section.

- NO_2 – The requirement is consistent with the NOx BACT emission limits. The limit is 2.0 ppmv, 1-hour average at 15% O_2 for the CCGS gas turbine, or 2.5 ppmv, 1-hour average at 15% O_2 for the SCGS gas turbine. Use of the SCR for control of NOx emissions is considered BACT for combustion gas turbines.
- SO_2 – The requirement is to use pipeline quality natural gas. LADWP will use pipeline natural gas for the gas turbines. Compliance is expected.
- CO – The most stringent emission limit is 2.0 ppmv based on 1-hour average at 15% O_2 for a combined cycle gas turbine, 4.0 ppmv based on 1-hour average at 15% O_2 for a combined cycle gas turbine. Therefore, the BACT limit is set at 2 ppmv for the CCGS and 4 ppmv for the SCGS. LADWP has proposed the same emission limits. Compliance is achieved.

BACT applies to the standby generator. The standby generator complies with the BACT consistent EPA Tier 2 emission standards.

In addition to the BACT requirement other requirements of this regulation may be triggered based on whether the new or modified source causes a significant increase of emissions. The Scattergood Generation Station is a major source per PSD definitions. The repower project will be considered a modification to the existing major source. A significant increase, defined as an increase of 40 tons/year of either NO_2 or SO_2 or 100 tons/year of CO emissions, would trigger the PSD analysis requirement. The repower project's potential emissions are compared with the existing emissions in the next two tables.

Table 22 Potential to Emit of the New Equipment

Pollutant	CCGS[(1)]	SCGS[(2)] (two units)	Standby Generator	Total
CO (tons/year)	156.9	50.6	0	207.5
NO_2 (tons/year)	83.6	69.2	0	152.8
SO_2 (tons/year)	5.1	2.6	0	7.7

(1) Page 96, Table A-13, Appendix A
(2) Page 107, Table B-11, Appendix B

Table 23 Emission Change Summary

Pollutant	Boiler 3 and Boiler 1 Actual Emissions (tons) [a]	New Power System (tons/yr)	Emissions Change (tons/yr)
CO	330.4	207.5	-122.9
NO_2	20.1	152.8	132.7
SO_2	1.8	7.7	5.9
a – Boiler emissions are based on actual emissions of year 2010 and 2011			

Therefore, PSD analysis is not required for CO and SO_2. PSD analysis is required for NO_2 only.

The following analyses are required for a facility having a significant emission increase under Rule 1703.

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

As required by this regulation, the District sent the PSD analysis and modeling materials to the following affected officials on May 25, 2012:

Gerardo Rios, US EPA, Region IX
John Notar, Federal Land Manager
Mike McCorison, Air Quality Specialist, USDA Forest Services

The following methodology was used in performing the PSD analysis for NO_2.

1. Determine whether pre-construction monitoring is required

Preconstruction monitoring is required if the air quality impacts are greater than the following amounts:

NO_2: 14 μg/m^3, annual average

The application submitted modeling results that showed the maximum NO_2 impact of 0.36 μg/m^3, ground level annual average. Since the level does not exceed the preconstruction monitoring threshold preconstruction monitoring is not required, and that monitoring data from nearby monitoring stations can be used to determine ambient air quality.

2. Assessment of significance under PSD

The air quality impacts are considered significant if they exceed the following amounts:

NO_2: 7.5 μg/m^3, 1-hour average
NO_2: 1.0 μg/m^3, annual average

The 1-hour average significant impact level (SIL) limit was recently suggested by the EPA. The facility modeled the entire new power system as one emission group. The highest impact operating conditions are:

1-hour impact: The CCGS in cold startup and the SCGS in startup.
Annual impact: The CCGS in normal operation, 8,760 hours per year and the SCGS in normal operation, 5,168 hours per year.

The modeled impacts are:

NO_2: 7.1 μg/m^3, 1-hour average
NO_2: 0.36 μg/m^3, ground level annual average

The impacts are below the significance thresholds. Since the project does not exceed the significance thresholds, an increment consumption analysis is not required.

3. Determine ambient air quality impacts

Because the estimated 1-hour average and annual average NO_2 concentrations are less than the significant thresholds, a full impact analysis is not required. Modeling analysis is required for

NO_2 1-hour and annual impacts to demonstrate compliance with the ambient air quality standards. The 1-hour NO_2 standard is 100 ppb, or 188 μg/m^3, 98th percentile of 3-year average. The annual NO_2 standard is 100 μg/m^3. The background NO_2 concentration is provided in the next table.

Table 24 Background NO_2 concentrations at Southwest Coastal LA County Station (820)

	98th percentile background NO_2 concentration ppm (μg/m^3)			
	2008	2009	2010	Average
1-hour 98th percentile	0.076 (142.9)	0.07 (131.6)	0.061 (114.7)	0.069 (129.7)

The data confirms that NO_2 is an attainment pollutant.

Table 25 Impact to Ambient Air Quality, Entire Facility

Pollutant	Averaging Time	Impacts (μg/m^3)	Background Concentration(μg/m^3)	Total Impact (μg/m^3)	Most Stringent Air Quality Standard (μg/m^3)	Results
NO_2	1-hour	7.1	129.7	136.8	188	Acceptable
	Annual	0.36	29.9	30.3	100	Acceptable

Therefore, the emissions do not cause violation of the most stringent air quality standards.

The modeling analysis was initially submitted to AQMD in May 2012. AQMD reviewed the analysis and determined that the modeling methodology was consistent and acceptable.

4. Determine Visibility and Soil Impacts in Class I areas

The impacts were analyzed on Class I areas that are within 100 kilometers of the project site. The following Class I areas are within 100 km of the Scattergood Generating Station:

San Gabriel Wilderness Area (54 km)
Cucamonga Wilderness Area (64 km)

The results of the haze analysis were compared to a 5-percent threshold change in background extinction coefficient to determine if the proposed project would significantly contribute to regional haze at the Class I areas. The modeling results showed that the maximum percent change in extinction coefficient for all the Class I areas were satisfactory (less than 5%).

The results of the Class I PSD increment analysis showed that the model predicted concentrations are well below the EPA proposed Class I significance thresholds. Therefore, no further modeling was required for PSD increment analysis.

The results of the acid deposition analysis showed that nitrogen and sulfur deposition impacts are well below the Deposition Analysis Threshold. Therefore, adverse acid deposition impacts attributable to the Scattergood power equipment emissions are not likely to occur.

The federal land manager concurs with the PSD analysis. The federal land manager has determined that the project will not have adverse impacts to Class I areas.

Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases, Gas Turbines
This rule establishes preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs defined as an aggregate group of six GHGs: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

This rule is consistent with federal PSD rule as defined in 40 CFR Part 52.21. Several specific sections of the 40 CFR Part 52.21 are excluded by this rule. This rule requires the owner or operator of a new major source or a major modification to obtain a PSD permit prior to commencing construction. EPA is currently in the process of adopting Rule 1714 in the State Implementation Plan (SIP). EPA published its proposed approval of Rule 1714 in the Federal Register on August 29, 2012, with the public comment period ending on September 28, 2012. The final approval of Rule 1714 is expected to be published in the Federal Register in December 2012. Once the EPA's final approval becomes effective (30 days after the publication in the Federal Register) AQMD will become the permitting authority of the GHG PSD Permit.

Until EPA has issued its final approval and it has gone into effect, EPA is still the responsible agency for issuance of any PSD permits for GHG sources. Since EPA's approval is expected to be imminent, the AQMD has proceeded with GHG PSD evaluation for this proposed project to streamline the permit processing.

DETERMINE PSD APPLICABILITY

EPA has developed the PSD and Title V Permitting Guidance Document for Greenhouse Gases (March 2011). For permits issued on or after July 1, 2011 PSD applies to GHGs if:

- The source is otherwise subject to PSD (for another regulated NSR pollutant), and
- The source has a GHG PTE equal to or greater than 75,000 TPY CO2e

The Scattergood facility is an existing PSD major source because of its NOx and CO emissions. The new power system will have more than 1 million tons per year CO2e emissions, as calculated in Appendix E. The contemporaneous increase, after considering de-rate of Boiler 1 and shutdown of Boiler 3, will exceed 75,000 tons per year. Therefore, the project is subject to the GHG PSD analysis.

PSD BACT ANALYSIS

EPA has recommended the 5-step "top-down" process to determine BACT for GHGs.

1. Identify all available control options
2. Eliminate technically infeasible options
3. Ranking of controls
4. Economic, energy, and environmental impacts
5. Selecting BACT

The step-by-step BACT analysis is conducted.

Step 1 Identify All Available Control Options

The available CO_2 control technologies, as determined by EPA and Department of Energy, are:

A. Carbon Capture and Sequestration (CCS)
B. Lower Emitting Alternative Technology
C. Thermal Efficiency

The technologies are described and discussed in the next sections.

A. Carbon Capture and Sequestration (CCS)

CCS is a process that captures, transports, and sequesters CO_2 emissions.

Capturing of CO_2 Emissions

Combustion flue gas may be processed for the purpose of separation and capture of carbon dioxide. Amine-based solvent systems are available in commercial use for scrubbing CO_2 from industrial flue gases and process gases. Solid sorbents are also available to capture CO_2 from flue gas through chemical adsorption or physical adsorption. However, commercially available systems are not presently available to process flue gas from a commercial power plant.

Transportation of CO2 Emissions

Once captured CO_2 would have to be transported to a storage site. For geologic sequestration, a pipeline is typically used to transport the CO_2 as a critical fluid to the sequestration location. The Technical Advisory Committee for the California Carbon Capture and Storage Review Panel stated in the August 2010 report that there are no existing CO_2 pipelines in California. In addition, there are no CO_2 pipeline projects underway in California.

Sequestration of CO_2 Emissions

There are several sequestration approaches.

Geologic Sequestration

Under geologic sequestration the captured CO_2 is compressed and transported to a sequestration location. CO_2 is injected into underground at high pressure, and remains a supercritical fluid underground. Over time the CO_2 can dissolve into surrounding water and rocks, creating solid carbonate minerals.

There are several geologic formations identified in California that might provide a suitable site for geologic sequestration. Several sites near the Scattergood facility have been identified. They are the old petroleum production area in Long Beach, a formation in the Lower San Joaquin Valley, and a site located in Ventura County. While these sites may eventually prove to be suitable, the geotechnical analyses needed to confirm their suitability have not been conducted. In addition, there are no available pipelines to transport captured CO_2 to the sequestration site.

Ocean Storage

In lieu of injecting CO_2 underground as in geologic sequestration, ocean storage is accomplished by injecting CO_2 into the ocean water typically at depth of greater than 1,000 meters. CO_2 is expected to dissolve or form into a horizontal lens which would delay the dissolution of CO_2 into the surrounding environment.

Mineral Carbonation

Mineral carbonation is the reaction of CO_2 with metal oxides to form metal carbonates. Metal oxides are abundant in silicate minerals and in waste streams. The natural reaction of CO_2 with metal oxides is a very slow process. The reaction time can be increased by enhancing the purity of these metal oxides. Large scale production of metal oxides to meet the demand of electrical generation is very energy and cost intensive.

B. Lower Emitting Alternative Technology

Lower emitting alternative technologies for energy generation are available both on the demand side and on the production side. If demand for energy is reduced a utility's generation capacity can be reduced, thus lowering GHG emissions.

Demand-side resource programs include both energy efficiency, aimed at reducing total energy consumption, and demand response, aimed at reducing peak demand or shifting demand from peak to off-peak periods. Energy efficiency programs initiated by LADWP include incentives and rebates for the replacement of older, energy-wasting equipment with new energy-efficient equipment, including air conditioning systems, lighting, and large appliances. LADWP energy efficiency programs also offer incentives and guidelines for new construction and renovations that contribute to Leadership in Energy and Environmental Design (LEED)-certified buildings as well as free energy audits to provide commercial customers recommendations and strategies to reduce energy consumption. Consistent with California state legislation AB 2021, the LADWP has approved energy efficiency savings goals of 1 percent per year to achieve a 10 percent reduction in energy consumption from 2007 to 2017. These programs have reduced long-term peak demand by 270 megawatts (MW) and consumption by 890 gigawatt hours (GWh). Demand response programs include increasing the efficiency of LADWP system capabilities such that energy is dispatched to more effectively track actual demand, and agreements with commercial and industrial customers to curtail load during peak periods. Through these programs, LADWP expects to reduce system generation capacity by approximately 500 MW by 2030.

On the production side LADWP has adopted a renewable portfolio standard (RPS) intended to increase the amount of energy generated from renewable energy sources. The RPS sets up a goal to generate a certain percentage of the energy delivered to the customer from renewable resources by a certain date. LADWP has achieved the objective of providing 20 percent of its annual retail sales from renewable energy resources by 2010. The RPS has a further goal of providing 35 percent of its annual retail sales from renewable sources by 2020. These objectives meet or exceed the RPS objectives mandated by the legislature for California utilities. Renewable resources under development or consideration by LADWP include small hydroelectric, biomass, digester gas, waste gas, landfill gas, solar thermal, geothermal, solar photovoltaics, fuel cells with renewable fuels, ocean wave technologies, wind, and other sources.

Distributed generation (DG) is an alternative to centralized power generation such as a fossil fuel power plant. It places small electric generators of various types at or near the point of demand, thus reducing losses incurred during power transmission. DG systems include fuel cells, solar photovoltaics, and micro turbines. According to the LADWP Power Integrated Resources Plan (2010) it is estimated that the DG programs will reduce required system capacity by over 300 MW and energy use by over 1,800 GWh annually by 2017.

Although these programs are technically feasible, they do not represent a feasible alternative to the project because their implementation has already been accounted for in the assessment of the need for the project. The proposed project is complementary to programs such as energy efficiency, demand response, distributed generation, and renewable energy. Furthermore, the proposed project will integrate intermittent renewable energy sources identified in the RPS into the LADWP generation system more effectively.

All of the above discussed lower GHG emitting technologies would fundamentally redefine the project and alter its business purpose. According to PSD and Title V Permitting Guidance for Greenhouse Gases published by EPA in November 2010, EPA does not require a BACT analysis to redefine an applicant's project.

> *While Step 1 [of a BACT Analysis] is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.*

Consequently, no additional lower emitting alternative technologies are feasible to incorporate into the project without fundamentally changing the business purpose of the Project.

C. Thermal Efficiency

Power generation through fossil fuel combustion is a chemical reaction process. The thermal efficiency is defined as the ratio of the net power produced and the heating values of the fuel. The plant efficiency varies from 30% to over 60%, depending on many factors. The heat rate, measured in Btu/kWh, is generally used as a thermal efficiency indicator. The thermal efficiency is at the highest when the reaction is at stoichiometric, and at the time when CO_2 emissions are the highest.

The following factors affect the thermal efficiency of a power plant:

- Thermal dynamic cycle selection, combined cycle versus simple cycle
- Combustion turbine performance, compression ration and turbine design temperature

- Combustion turbine startup time, load transition time
- Steam turbine startup time, load following time
- Fuel selection

The repower project is proposing to combust natural gas, the lowest emitting fossil fuel available. It includes a combined cycle generation system (CCGS) and a simple cycle generation system (SCGS). The CCGS has a higher cycle thermal efficiency than the simple cycle systems. Energy is recovered in the heat recovery steam generator (HRSG) and is used to generate power in the steam turbine generator (STG). The Rapid Start Process (RSP) to minimize emissions during startup and increase the efficiency of the power plant. LADWP plans to use the CCGS in the base load operation. The SCGS compliments the CCGS by providing demand-following capability. The two GE LMS100 units have the highest thermal efficiencies (45%) among the simple cycle gas turbine generators.

Although new power generating system would emit GHG emissions, the high thermal efficiency of the new power generating equipment and the system build-out of renewable resources in California would result in a net cumulative reduction of GHG emissions from new and existing fossil resources.

With the adoption of Senate Bill 2 on April 12, 2011, California's Renewable Portfolio Standard (RPS) was increased from 20 percent by 2010 to 33 percent by 2020. To meet the new RPS requirements, the amount of dispatchable, high-efficiency, natural gas generation used as regulation resources, fast ramping resources, or load following or supplemental energy dispatches will have to be significantly increased. The construction of the Scattergood new power generating system will aid in the effort to meet California's RPS standard. Finally, the operation of the new power generating system will enhance the overall efficiency of LADWP's electricity system operation and thereby reduce GHG emissions.

<u>Step 2 Eliminate Technically Infeasible Options</u>

The second step for the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to determine the technical feasibility. The technology is feasible only when the technology is available and applicable. A technology that is not commercially available for the scale of the project is also considered infeasible. An available technology is applicable if it can reasonably be installed and operated on the proposed project.

A. <u>Carbon Capture and Sequestration (CCS)</u>

The technical feasibility of each step of the CCS is discussed below.

Carbon Capture Technology

Solvent-based capture technology for a commercial scale power plant has only been demonstrated for a fraction of the flue gas. A solvent-based carbon capture process is currently judged to be technologically infeasible for a commercial power plant application.

Sorbent-based capture technology can be used for post-combustion capture of CO_2. However, the technology has not been demonstrated on combined-cycle gas turbine power plants. A sorbent-based carbon capture process is currently judged to be technologically infeasible for a natural gas-fired commercial power plant application.

Membrane-based capture technology is commercially available in the chemical industry for CO_2 removal but has not been demonstrated in practice for power generation applications. A membrane-based carbon capture process is currently judged to be technologically infeasible for a commercial power plant application.

CO_2 Transportation

The basic technologies required for CO_2 transportation (i.e., pipeline, tanker truck, ship) are in commercial use today for a number of applications and can be considered commercially available for liquid CO_2.

CO_2 Sequestration

Geologic sequestration has been demonstrated on a pilot scale. However, a number of significant technical issues remain to be resolved before the technology can be applied to a successful commercial scale application at a specific site. At this moment the technical feasibility for geological sequestration for the new power generating system cannot be determined. Therefore CCS using geological sequestration cannot be demonstrated to be technically feasible in practice for the new power generating system.

Ocean storage and its ecological impacts are still in the research phase. It is not commercially available.

Mineral carbonation is technically feasible, as reaction chemistry is well understood. However, the sequestration of CO_2 through mineral carbonation has not been demonstrated on a commercial scale.

Summary of CCS Feasibility

In summary, the post-combustion carbon capture technologies are still in the developmental stage or pilot scale projects. These technologies would not be considered commercially available for the project size of a full-scale commercial power plant. In addition, there are no comprehensive standards in place defining requirements for long term sequestration. Therefore, CCS is not yet demonstrated in practice for a commercial-scale, natural gas fired power plant such as the Scattergood new power generating system. In consideration of the uncertainty in the technical feasibility of CCS and its emergence as a promising technology, CCS is carried forward in this BACT analysis as a potential GHG control technology. However, substantial evidence demonstrates that CCS is not yet demonstrated as technically feasible for the Scattergood new power generating system.

B. Lower Emitting Alternative Technology

As discussed previously, any of the commercially available low GHG-emitting technologies that could be implemented, are not feasible for this site and would fundamentally alter the business purpose of the emission source. As such, lower emitting alternative technology was not considered as part of the BACT analysis.

C. Thermal Efficiency

The California Senate Bill (SB) 1368 requires the California Public Utilities Commission (CPUC) to establish a GHG emission performance standard for all baseload utilities by February 1, 2007. The California Energy Commission (CEC) was required to establish a similar standard for local publicly owned utilities by June 30, 2007. The CEC has established a GHG performance standard of 1,100 pounds of CO_2 per net MWh for baseload publicly owned electrical utilities. The California Legislature in Assembly Bill (AB) 1613 (2007), as amended by AB 2791 (2008), established a CO_2 Emission Performance Standard (EPS) for combined heat and power facilities of 1,100 lbs CO_2/MWh. In 2010, the CEC promulgated its regulation to implement AB 1613 in its Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction Act (CEC 2010b).

The EPA released a prepublication version of a proposed rule on March 27, 2012 to establish, a new source performance standard (NSPS) for GHG emissions from fossil fuel-fired electric generating units. This standard will require the new fossil fuel-fired power plants to meet an output based standard (based on gross output power) of 1,000 lb CO_2/MWh on an average annual basis. This standard will apply to combined cycle generating systems. The proposed rule exempts simple cycle generating systems such as the SCGS. At this moment the proposed rule has not been finalized by EPA.

The CCGS will meet the California GHG emission performance standard of 1,100 pounds of CO_2 per net megawatt hour. As calculated in Appendix E, using a conservative annual operating schedule that includes startup, normal operation, shutdown and an average load factor of 50%, the CCGS will emit CO_2 at a rate of 1,022 lb CO_2 per net megawatt hour (0.511 MT CO_2/MWh). The GHG emissions will be 908 lbs CO_2 per net megawatt hour when the load factor improves to 75%. Therefore, the GHG emissions is expected to be at 1,022-908 pounds CO_2 per net MWh if the CCGS operates between the load factor of 50%-75%. This is below the 1,100 lbs CO_2 per net MWh California standard. This emission metric is also consistent with the emission limit established as GHG BACT for the Lower Colorado River Authority (LCRA) Thomas C. Ferguson Power Plant of 918 lb CO_2/MWh source-wide net output.

The SCGS is not subject to the 1,000 lbs CO2 per gross MWh EPA standard or the 1,100 lbs CO2 per net MWh California standard because it is not a baseload combined cycle generating system. The GE LMS100 is an advanced simple cycle gas turbine generator that incorporates inter-cooling to promote enhanced energy efficiency. It has the highest heat rate, i.e., thermal efficiency, among the currently available simple cycle gas turbine generators. The heat rate of the LMS100 is approximately 8,700 Btu/kWh (HHV), below the 9,000-10,000 Btu/kWh range of typical simple-cycle gas turbines. Consequently the GHG emissions are the lowest among simple cycle gas turbine generators. The GHG performance metrics calculations are included in the Appendix F. The expected GHG emissions are 1,341 – 1,108 lbs CO2 per net megawatt hour depending on load factors. The maximum annual CO2 emissions are 266,096 tons per LMS100 generator. The power plant operations include normal operation, startup operation, and shutdown operation.

The use of the most efficient commercially available simple-cycle gas turbine technology (GE LMS100), combined with good combustion operation and maintenance to maintain optimum efficiency, is determined to be BACT for GHG for the Scattergood Repowering Project SCGS.

The thermal efficiency for the new power generating system achieved by the state-of-the-art technologies is a technically feasible alternative for reducing GHG emissions from a fossil-fuel fired low efficiency power plant. In conclusion the combustion process inherent in the new power generating system is achieved in practice and is eligible for consideration under Step 3 of the BACT analysis.

<u>Step 3 - Rank Remaining Control Technologies</u>

While carbon capture and sequestration (CCS) was determined to be technically infeasible for the Scattergood repowering project, this option is carried forward in the BACT analysis to Step 3. The rank order of control, starting from the most effective control (1) to the least effective control (2), is as follows:

1. CCS
2. Thermal efficiency

The control effectiveness is discussed below.

A. Carbon Capture and Sequestration (CCS)

Post-combustion capture systems being developed are expected to be capable of capturing more than 90 percent of flue gas CO_2. At an assumed control efficiency of 90 percent, this would be equivalent to an emission rate of 10 percent of the California EPS, or approximately 110 lb CO_2/MWh. This makes CCS the top-ranked technology on a theoretical basis. However, as discussed in Step 2, CCS was found to be technically infeasible for the Scattergood new power generating system. In addition, the above assumed CO_2 control efficiency does not take into account the parasitic loss associated with operation of the CCS system and the increased CO_2 emissions that will occur to replace the parasitic energy loss.

B. Thermal Efficiency

Thermal efficiency is capable of lowering GHG emissions, but the potential is much less than CCS on a theoretic basis. As discussed in Section 2, the new power generating system already incorporates increased thermal efficiency in its design by incorporation of state-of-the-art combustion turbines with the addition of RPS startup capability. Since the parasitic load is already relatively low at this facility, further increases to thermal efficiency are not achievable without changing basic objectives of the power project, if at all, and hence are not required by EPA guidelines for GHG BACT.

Step 4 – Evaluating the Most Effective Controls

Step 4 of the BACT analysis is to evaluate the most effective control. This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down approach requires that the evaluation begin with the most effective technology.

A. Carbon Capture and Sequestration (CCS)

Because CCS is considered technically infeasible to apply for the Scattergood new power generating system it is not evaluated under this step.

B. Thermal Efficiency

The database review of BACT determinations described above identified four facilities with natural gas-fired combustion turbines for which a GHG BACT analysis was done:

- EPA issued the PSD Permit for the Palmdale Hybrid Power Project in October 2011. This project consists of a hybrid of natural gas fired combined cycle generating system (two GE 7FA combustion gas turbines and one shared steam turbine) integrated with solar thermal generating system. Based on EPA's analysis CCS was eliminated as a control option because it is deemed economically infeasible.
- EPA issued the PSD Permit for the Lower Colorado River Authority (LCRA) Project in November 2011. This project consists of a natural gas fired combined cycle generating system with two GE 7FA combustion gas turbines and a shared steam turbine. Based on the review of the available control technologies for GHG emissions, EPA concluded that BACT for LCRA was the use of new thermally efficient combustion turbines with applicable GHG emission limit.
- The Bay Area Air Quality Management District issued a GHG BACT determination for the Calpine Russell City Energy Center in 2010. According to a presentation by Calpine, thermal efficiency was the only feasible combustion control technology considered as CCS was determined to be not commercially available. Thermal efficiency was found to be the top level of control feasible for a combined-cycle power plant, and hence was the technology selected at GHG BACT for Russell City.
- EPA issued the PSD Permit for the Pio Pico Energy Center Project in November 2012. The project consists of three simple cycle GE LMS100 generators. EPA concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

As demonstrated by the EPA permits thermal efficiency is the most cost effective control technology for GHG emissions from power plants. In addition, the GE 7FA combustion turbine and the GE LMS100 combustion turbine are acceptable for GHG PSD permits under the BACT thermal efficiency requirement.

Step 5 – Select BACT

Based on the above analysis, thermal efficiency is the only technically and economically feasible alternative for CO_2/GHG emissions control at the Scattergood Generating Station. The current design of the facility meets the BACT requirement for GHG emission reductions.

The BACT limit shall be applicable to the entire operation conditions. Therefore, BACT is determined based on the facility proposed annual operating scenarios that take into consideration of load factor, equipment degradation over time, and operating hours. The detailed calculations are included in Appendix E.

Based on calculations of Appendix E the GE 7FA combined cycle generating system is expected to generate 931 lbs of CO_2 per net megawatt hours at 50% load, or 828 lbs of CO_2 per net megawatt hours at 100% load. The calculations are consistent with LADWP's calculations that are 936 lbs of CO2 per net megawatt hours at 50% load. Because BACT must apply at all loads the applicable BACT limit is set at 50% load, to be 936 lb/$_{net}$MWh. This limit ensures compliance with the California law SB1368 limit of 1,100 lb/$_{net}$MWh, and compliance with the proposed federal limit of 1,000 lb/$_{gross}$MWh for base load combined cycle generators. The equipment will also be subject to the CO2 emission limit of 1,026,128 tons per year. Compliance will be based on a 12-month rolling average as determined by using emission factors and fuel usage.

Based on calculations of Appendix E the GE LMS100 simple cycle generating system is expected to generate 1,271 lbs of CO2 per net megawatt hours at 60% load, or 1,096 lbs of CO2 per net megawatt hours at 100% load. The calculations are consistent with LADWP's calculations that are 1,260 lbs of CO2 per net megawatt hours at 60% load. Because BACT must apply at all loads the applicable BACT limit is set at 60% load, to be 1,260 lb/$_{net}$MWh. This limit is more stringent than the 1,328 lb/$_{gross}$MWh limit that EPA set for the Pio Pico Energy Center permit, which was derived at 50% load. The equipment will also be subject to the CO2 emission limit of 261,985 tons per year. Compliance will be based on a 12-month rolling average as determined by using emission factors and fuel usage.

OTHER PSD REQUIREMENTS

In addition to the BACT requirement the PSD requirements generally include air quality modeling, ambient monitoring, and additional impact analysis. The modeling analysis shall demonstrate that there will be no violations of any NAAQS or PSD increments. However, because there are currently no NAAQS or PSD increments established for GHGs, the modeling analysis requirement would not apply for GHGs even if PSD is triggered for GHGs. EPA does not require monitoring for GHGs in accordance with Section 52.21(i)(5)(iii) and Section 51.166(i)(5)(iii), and EPA does not require impact analysis from GHGs in the nearby Class I areas.

Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases, Circuit Breakers
EPA in the Pio Pico Energy Center PSD permit requires the circuit breakers be equipped with a leak detection system, and be calibrated according to manufacturer specifications. EPA considers it to be BACT for circuit breakers. EPA further argues that the requirement is not redundant to the CARB regulation to reduce GHG (SF_6) emissions from gas insulated switchgears, California Code of Registers, Subchapter 10, Article 4, §95350-§95359.

A facility condition F52.2 will be added to enforce the BACT requirement for the circuit breakers, using the same language as the EPA permit.

Rule 2005 – NSR for RECLAIM Pollutants
This regulation applies to NOx emissions.

1. BACT

For a combined cycle combustion turbine the most stringent NOx emissions limit is 2.0 ppmv, 15% O_2, dry, 1-hour average. The Inland Empire Energy Center has two GE H series combined cycle gas turbines that were permitted at 2.0 ppmv in 2005. The use of SCR combined with dry low NOx combustion technology will ensure that the gas turbine meets the 2.0 ppmv NOx limit.

For a simple cycle combustion turbine the most stringent NOx emissions limit is 2.5 ppmv, 15% O_2, dry, 1-hour average. The LADWP Haynes Generating Station have six GE LMS100 simple cycle gas turbines that were permitted at 2.5 ppmv in 2010. LADWP will use a SCR control system in conjunction with water injection to meet the 2.5 ppmv NOx limit.

2. MODELING

The facility is located in the South Coast air basin, which is in attainment of NO_2 emissions. Thus, Rule 2005(c)(1)(B) requires the facility to demonstrate, through modeling analysis, that the proposed NOx emission sources will not cause a violation of the most stringent ambient air quality standards. There are two air quality standards for NO_2, the newly adopted 1-hour federal standard of 100 ppb (188 $\mu g/m^3$) based on 98^{th} percentile of the last three year average, and annual California standard of 30 ppb (56 $\mu g/m^3$). The background air quality data from the South Coastal LA County Station 1 (080) are used in the modeling analysis. At this station, the 1-hour average background concentration is 129.8 $\mu g/m^3$ based on the 3-year average 98^{th} percentile, and the highest annual average background concentration is 29.9 $\mu g/m^3$.

The maximum project impacts of NO_X emissions were determined using the AERMOD model. Although the rule requires modeling analysis of NOx emissions impact from each individual permitted unit, the LADWP elected to model the impact from the entire new equipment as a group. The equipment group, which include the three turbines and the standby generator, are assumed operating concurrently and emitting NOx emissions collectively. This modeling approach is more stringent, and it satisfies the requirement of this rule. Results from the modeling analysis indicate that the highest 1-hour impact occurs when all three turbines are in the startup stage. The highest annual impact occurs when all three turbines are operating at full capacities, and the standby generator operating for 50 hours per year.

Table 26 provides a summary of the modeling results.

Table 26 NOx Emissions Modeling Results

	Background ($\mu g/m^3$)[a]	Modeling Impacts ($\mu g/m^3$)	Total NOx ($\mu g/m^3$)	Air Quality Standard ($\mu g/m^3$)	Violation
1-hour 98th percentile	129.8	7.2	137.0	188	No
Annual	29.9	0.36	30.3	56	No

a – Background concentration was measured at South Coastal Los Angeles County Meteorological Station 820.

The modeling results demonstrate that the proposed NOx emission sources will not cause a violation of the most stringent ambient air quality standards.

3. OFFSET (RTC)

The facility is required to demonstrate that it holds sufficient RTCs to offset the annual emission increase for the first year of operation using a 1-to-1 offset ratio. Furthermore, Rule 2005(b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). The repower project is expected to undergo commissioning operation in Year 2014. Since the facility is located in Zone 1, RTCs may only be obtained from Zone 1.

As calculated in Appendix G the total NOx RTC requirements of the repower project for the 1st year of operation is 331,363 lbs. This requirement is based on the emissions from the commissioning, and based on the annual operating schedule provided by LADWP. After the 1st year the project will require 309,854 lbs of NOx RTC per year. It is lower than the 1st year requirement since the emissions from the commissioning are not included.

LADWP will either purchase the required NOx RTCs from the open market or transfer credits from their other RECLAIM facilities. Compliance with the offset requirement is expected.

4. ADDITIONAL REQUIREMENTS FOR MAJOR SOURCES

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

A) Certify that all major sources in the state under control of the applicant are in compliance with all applicable federal emissions standards.

B) Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source.

C) Compliance with CEQA

D) Protection of Visibility

The LADWP certifies in the permit application that all major sources under their control in the state currently comply with federal regulations. An alternative analysis under the California Environmental Quality Act (CEQA) process is being performed as part of the EIR. The minimum distance between the project site and the nearest Class I area (San Gabriel Wilderness Area) is 54 km, which is greater than the maximum distance requirement of 29 kilometers. Thus, no visibility analysis is required for the Scattergood project site. Thus, the above three requirements have been met for the Scattergood repower project.

<u>Rule 2012 – Monitoring Recording and Record Keeping for RECLAIM</u>
The Scattergood Generation Station is currently in compliance with all monitoring, record-keeping, and reporting requirements of NO_X RECLAIM. The new gas turbine generators will be classified as major sources for RECLAIM purposes. As such each turbine will be provided with a NO_X CEMS and a fuel meter, and emissions will be reported through a remote terminal unit (RTU) on a daily basis. The CEMS will be installed within 12 months from the date of installation of the turbines. Thus, the operation of the new turbines will be in compliance with Rule 2012.

The standby diesel generator is a process unit. The RECLAIM reporting factor is 170.5 lbs per 1,000 gallons.

<u>Regulation XXX – Title V Operating Permit</u>
The Scattergood Generation Station is a federal Title V facility and is subject to Title V requirements. The addition of the new turbines is considered a Significant Permit Revision as defined in Rule 3000.

The facility is required to provide public notification of the repower project. EPA will also be provided with this information for their review comments (45 day review period). The Title V public notice will be combined with Rule 212 notice, which is also required for this project. Rule 3006 requires that the notice contain the following:

(i) The identity and location of the affected facility.

(ii) The name and mailing address of the facility's contact person.

(iii) The identity and address of the SCAQMD as the permitting authority processing the permit.

(iv) The activity or activities involved in the permit action.

(v) The emissions change involved in any permit revision.

(vi) The name, address, and telephone number of a person whom interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision.

(vii) A brief description of the public comment procedures provided.

(viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

RECOMMENDATION

Based on the engineering evaluation the new equipment is expected to comply with all federal, state, and local rules and regulations. It is recommended that the District approve the proposed project and issue permits to construct after 1) the 30-day public comment period, 2) the 45-day EPA review period, and 3) EPA's approval of Rule 1714 and GHG PSD delegation. The permits will be subject to the following conditions.

CONDITIONS

Facility Conditions

F2.1 The operator shall limit emissions from this facility as follows:

Contaminant	Emissions Limit
PM	Less than 100 tons in any one year

For the purpose of this condition, the PM shall be defined as particulate matter with aerodynamic diameter of 2.5 microns or less.

The operator shall not operate any of the new Units 4-7 unless it demonstrates compliance with this limit.

For purposes of demonstrating compliance with the 100 ton per year limit the operator shall determine the $PM_{2.5}$ emissions for each of the major sources at the facility by calculating a 12-month rolling average using the following formula:

$PM_{2.5} = (FF_1*EF_1+ FF_2*EF_2+ FF_4*EF_4+ FF_6*EF_6+ FF_7*EF_7+ FF_{d1}*EF_{d1}+ FF_{d2}*EF_{d2})/2000$

Where:

PM2.5 = PM2.5 emissions in tons per year

FF_1= fuel flow for Unit 1 in MMscf, Unit 1 is a boiler generator
FF_2= fuel flow for Unit 2 in MMscf, Unit 2 is a boiler generator
FF_4= fuel flow for Unit 4 in MMscf, Unit 4 is the GE 7FA.05 turbine generator
FF_6= fuel flow for Unit 6 in MMscf, Unit 6 is the GE LMS100PA turbine generator
FF_7= fuel flow for Unit 7 in MMscf, Unit 7 is the GE LMS100PA turbine generator
FF_{D1}= fuel flow for standby generator D19 in Mgal
FF_{D2} = fuel flow for standby generator D116 in Mgal.

EF_1= emission factor for Unit 1 = 7.6 lb/MMscf
EF_2= emission factor for Unit 2 = 7.6 lb/MMscf
EF_4= emission factor for Unit 4 = 5.10 lb/MMscf
EF_6= emission factor for Unit 6 = 6.70 lb/MMscf
EF_7= emission factor for Unit 7 = 6.70 lb/MMscf
EF_{D1}= emission factor for D19 = 34.4 lb/Mgal
EF_{D2} = emission factor for D116 = 0.3 lb/Mgal

Any changes to these emission factors must be approved in advance by the District in writing and be based on unit specific source tests performed using a District approved testing protocol.

[Rule 1325]

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

The facility shall submit a detailed retirement plan for the permanent shutdown of Boiler 3 (Device 22), describing in detail the steps and schedule that will be taken to render Boiler 3 permanently in operable.

The retirement plan must be submitted to AQMD by January 1, 2014. AQMD shall notify LADWP whether the plan is approvable. If AQMD notifies LADWP that the plan is not approvable, LADWP shall submit a revised plan addressing AQMD's concerns within 30 days.

LADWP shall provide AQMD by December 31, 2015 with a notarized statement that Boiler 3 is permanently shut down and that any re-start or operation of the unit shall require new Permit to Construct and be subject to all requirements of nonattainment new source review and the prevention of significant deterioration program.

LADWP shall notify AQMD 30 days prior to the implementation of the approved retirement plan for permanent shut down of Boiler 3, or advise AQMD as soon as practicable should LADWP undertake permanent shutdown prior to December 31, 2015.

LADWP shall cease operation of Boiler 3 (Device 20) within 90 calendar days of the first fire of Unit 4. Within 90 calendar days of the first fire of either Unit 6 or Unit 7 LADWP shall complete the Boiler 1 (Device D24) de-rate project by removing cam lobes 5 through 8 to disable steam control valves 5-8 permanently, and modifying cam lobe 4 to reduce the opening of steam control valve 4. After 90 calendar days of the first fire of either Unit 6 or Unit 7 LADWP shall not operate Boiler 1 unless the de-rate project is complete and approved by AQMD.

[Rule 1304(a)(2)]

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

For the circuit breakers serving Units 4, 6, and 7 the facility shall install, operate, and maintain enclosed-pressure SF6 circuit breakers with a maximum annual leakage rate of 0.5% by weight. The circuit breakers shall be equipped with a 10% by weight leak detection system. The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations shall be maintained on site.

The total CO2e emissions from the circuit breakers serving Units 4, 6, and 7 shall not exceed 55.4 tons per calendar year.

[Rule 1714]

Device Conditions of the New Equipment

A63.2 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	26,730 LBS IN ANY 1 CALENDAR MONTH
VOC	4,425 LBS IN ANY 1 CALENDAR MONTH
PM10	7,393 LBS IN ANY 1 CALENDAR MONTH
SOx	871 LBS IN ANY 1 CALENDAR MONTH

The above limits apply after the equipment is commissioned.

The operator shall calculate the emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 3.05 lbs/mmscf, PM10: 5.10 lbs/mmscf, SOx: 0.60 lbs/mmscf.

During the commissioning process the operator shall calculate the emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 16.11 lbs/mmscf, PM10: 6.32 lbs/mmscf, SOx: 0.71 lbs/mmscf.

The operator shall calculate the emission limits for CO after the CO CEMS certification based upon readings from the AQMD 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 by using monthly fuel use data and the following factors: natural gas commissioning: 583.02 lbs/mmscf, normal operation: 18.45 lbs/mmscf.

[Rule 1303, Rule 1703 – PSD]

[Device subject to this condition: D96]

A63.3 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	6,760 LBS IN ANY 1 CALENDAR MONTH
VOC	1,692 LBS IN ANY 1 CALENDAR MONTH
PM10	4,296 LBS IN ANY 1 CALENDAR MONTH
SOx	384 LBS IN ANY 1 CALENDAR MONTH

The above limits apply after the equipment is commissioned. The above limits apply to each turbine.

The operator shall calculate the emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 2.64 lbs/mmscf, PM10: 6.70 lbs/mmscf, SOx: 0.60 lbs/mmscf.

During the commissioning process the operator shall calculate the emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 11.59 lbs/mmscf, PM10: 6.95 lbs/mmscf, SOx: 0.60 lbs/mmscf.

The operator shall calculate the emission limits for CO after the CO CEMS certification based upon readings from the AQMD 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 by using monthly fuel use data and the following factors: natural gas commissioning: 208.27 lbs/mmscf, normal operation: 10.54 lbs/mmscf.

[Rule 1303, Rule 1703 – PSD]

[Device subject to this condition: D104, D110]

A99.4 The 29.54 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[Rule 2012]

[Device subject to this condition: D96]

A99.5 The 9.82 lbs/mmscf NOx emission limit(s) shall only apply during the interim period after commissioning to report RECLAIM emissions.

[Rule 2012]

[Device subject to this condition: D96]

A99.6 The 98.06 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[Rule 2012]

[Device subject to this condition: D104, D110]

A99.7 The 15.9 lbs/mmscf NOx emission limit(s) shall only apply during the interim period after commissioning to report RECLAIM emissions.

[Rule 2012]

[Device subject to this condition: D104, D110]

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

[Rule 2005 – BACT, Rule XVII – PSD]

[Device subject to this condition: D96]

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

[Rule XVII – PSD]

[Device subject to this condition: D96]

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

[Rule 1303 – BACT]

[Device subject to this condition: D96]

A195.8 The 2.5 PPMV NOx emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup and shutdown periods.

[Rule 2005 – BACT, Rule XVII – PSD]

[Device subject to this condition: D104, D110]

A195.9 The 4.0 PPMV CO emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup and shutdown periods.

[Rule XVII – PSD]

[Device subject to this condition: D104, D110]

A195.10 The 2.0 PPMV VOC emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup and shutdown periods.

[Rule 1303 – BACT]

[Device subject to this condition: D104, D110]

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

[Rule 475]

[Device subject to this condition: D96, D104, D110]

C1.8 The operator shall limit the number of startups to less than 62 in any one calendar month.

The number of cold startups shall not exceed 5 time per month and the number of non-cold startups shall not exceed 57 times per calendar month.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the steam turbine has been shut down for 72 hours or more. A cold startup shall not exceed 166 minutes. The NOx emissions of a cold startup shall not exceed 111 lbs. A non-cold startup shall not exceed 88 minutes. The NOx emissions from a non-cold startup shall not exceed 50 lbs.

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

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

[Rule 1303, Rule 1703 – PSD, Rule 2005]

[Device subject to this condition: D96]

C1.9 The operator shall limit the number of shutdowns to less than 62 in any one calendar month.

Shutdown time shall not exceed 25 minutes per shutdown. The NOx emissions from a shutdown event shall not exceed 25 lbs.

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

[Rule 1703 – PSD, Rule 2005– Offset]

[Device subject to this condition: D96]

C1.11 The operator shall limit the number of startups to less than 124 in any one calendar month.

The number of startups per day shall not exceed 4 time per day.

A startup shall not exceed 25 minutes. The NOx emissions from a startup shall not exceed 20 lbs. The beginning of startup occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. If during startup the process is aborted the process will count as one startup.

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

[Rule 1703 – PSD, Rule 2005– Offset]

[Device subject to this condition: D104, D110]

C1.12 The operator shall limit the number of shutdowns to less than 124 in any one calendar month.

Shutdown time shall not exceed 11 minutes per shutdown. The NOx emissions from a shutdown event shall not exceed 3 lbs.

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

[Rule 1703 – PSD, Rule 2005– Offset]

[Device subject to this condition: D104, D110]

D12.7 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 2005– BACT, Rule 1703- PSD]

[Devices subject to this condition: C101, C107, C107]

D12.8 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. The temperature shall be between 734 °F and 850 °F.

[Rule 2005– BACT, Rule 1703- PSD]

[Devices subject to this condition: C101, C107, C107]

D12.9 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. The pressure differential shall be between 4.0 and 5.8 inches water column.

[Rule 2005– BACT, Rule 1703- PSD]

[Devices subject to this condition: C101, C107, C107]

D12.3 The operator shall install and maintain a non-resettable totalizing time meter to accurately indicate the elapsed operating time of the engine.

[Rule 1304-Excemptions, Rule 1303(b)-Offset, Rule 2012]

[Devices subject to this condition: D116]

D12.10 The operator shall install and maintain a non-resettable elapsed fuel meter to accurately indicate the engine fuel consumption.

[Rule 1304-Exemptions, Rule 2012]

[Devices subject to this condition: D116]

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
PM10 emissions	Approved District Method	District Approved Avg. Time	Outlet of the SCR
PM2.5 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 or three hundred hours of operation after startup. 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 90 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

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

The test shall be conducted when this equipment is operating at loads of 100 and 75 percent of maximum load for the NOx, CO, VOC, and ammonia tests. The PM10 test shall be conducted when this equipment is operating at 100 percent of maximum load.

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

[Device subject to this condition: D96, D104, D110]

D29.2 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
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.

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. 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]

[Device subject to this condition: D96, D104, D110]

D29.3 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 10 days prior to the test.

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

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

[Rule 1303 – BACT]

[Devices subject to this condition: C101, C107, C113]

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

CO concentration in ppmv

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

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

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

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

CO Emission Rate, lbs/hr = $K*Cco*Fd[20.9/(20.9\% - \%O_2\ d)][(Qg * HHV)/10^6]$, where

$K = 7.267 * 10^{-8}$ (lb/scf)/ppm

Cco = Average of four consecutive 15 min. average CO concentration, ppm

Fd = 8710 dscf/MMBTU natural gas

$\%O_2$ d = Hourly average % by vol. O_2 dry, corresponding to Cco

Qg = Fuel gas usage during the hour, scf/hr

HHV = Gross high heating value of fuel gas, BTU/scf

[Rule 1703 – PSD]

[Device subject to this condition: D96, D104, D110]

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

NOx concentration in ppmv

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

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

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

[Rule 2012, Rule 2005-BACT, Rule 1703-PSD]

[Device subject to this condition: D96, D104, D110]

E116.1 This engine shall not be used as part of an interruptible service contract in which a facility receives a payment or reduced rates in return for reducing electric load on the grid when requested by the utility or the grid operator.

[Rule 1470, Rule 1304-Excemptions, Rule 1303(b)-Offset]

[Devices subject to this condition: D116]

E179.3 For the purpose of the following condition number(s) continuously record shall be defined as recording at least once every 15 minutes and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition no. D12.7

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

[Devices subject to this condition: C101, C107, C113]

E179.4 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. D12.8

Condition no. D12.9

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: C101, C107, C113]

E193.2 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the Final Environmental Impact Report (EIR), State Clearing House #2011011079.

[CEQA]

[Device subject to this condition: D96, C101, D104, C107, D110, C113, D116, D118, D119]

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

The commissioning period shall not exceed 460 hours of operation for the combustion turbine from the date of initial turbine start-up.

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

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

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

[Device subject to this condition: D96]

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

The commissioning period shall not exceed 176 hours of operation for the combustion turbine from the date of initial turbine start-up.

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

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

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

[Device subject to this condition: D104, D110]

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

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

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

where a=NH_3 injection rate (lb/hr)/17(lb/lb-mol), b= dry exhaust flow rate (scf/hr)/(385.5 scf/lb-mol), c = change in measured NOx across the SCR, ppmvd at 15 percent O_2.

The operator shall install a NOx analyzer to measure the SCR inlet NOx ppm accurate to within +/- 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia. The ammonia slip calculation procedure shall be in-effect no later than 90 days after initial startup of the turbine.

[Rule 1303 – BACT]

[Devices subject to this condition: C101, C107, C113]

E193.6 The operator shall operate and maintain this equipment according to the following requirements:

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

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

GHG = 60.139* FF

Where, GHG is the greenhouse gas emissions in tons of CO2e and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per net megawatt-hours on the 12-month rolling average. The GHG emissions from this equipment shall not exceed 1,026,128 tons per year. The average GHG emissions shall not exceed 931 lbs per net megawatt-hours.

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

[Rule 1714]

[Devices subject to this condition: D96]

E193.7 The operator shall operate and maintain this equipment according to the following requirements:

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

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

GHG = 60.139 * FF

Where, GHG is the greenhouse gas emissions in tons of CO2e and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per net megawatt-hours on the 12-month rolling average. The GHG emissions from this equipment shall not exceed 261,985 tons per year. The average GHG emissions shall not exceed 1,271 lbs per net megawatt-hours.

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

[Rule 1714]

[Devices subject to this condition: D104, D110]

E448.1 The operator shall comply with the following requirements:

Change oil and filter every 500 hours of operation or annually, whichever comes first; Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

The engine and the control device shall be operated and maintained in accordance with the manufacturer's written emission-related instructions or procedures developed by the operator that are approved by the engine manufacturer. Changes to those emission-related settings that are set by the manufacturer are not allowed.

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

A. The internal combustion engine shall not be operated for maintenance and testing or any other non-emergency use while the diesel particulate filter media is removed; and
B. The diesel particulate filter's filter media shall be returned and re-installed within 10 working days from the date of removal; and
C. The owner or operator shall maintain records indicating the date(s) the diesel particulate filter's filter media was removed for cleaning and the date(s) the filter media was re-installed. Records shall be retained for a minimum period of 36 months.

[Rule 1470, 40 CFR 63.6603, 40 CFR 63.6625(e)]

[Devices subject to this condition: D116]

E448.3 The operator shall comply with the following requirements:

This engine shall not be operated more than 200 hours in any one year, which includes no more than 50 hours per year and 4.2 per month for maintenance and testing as required in rule 1470(c)(2).

Operation beyond the allotted time for engine maintenance and testing shall be allowed only in the event of a loss of grid power or up to 30 minutes prior to a rotating outage, provided that the utility distribution company has ordered rotating outages in the control area where the engine is located or has indicated that it expects to issue such an order at a certain time, and the engine is located in a utility service block that is subject to the rotating outage. Engine operation shall be terminated immediately after the utility distribution company advises that a rotating outage is no longer imminent or in effect.

[Rule 1470, Rule 1304-Excemptions, Rule 1303(b)-Offset]

[Devices subject to this condition: D116]

E448.4 The operator shall comply with the following requirements:

The engine and the Johnson Matthey CRT+ diesel particulate filter shall be operated in accordance with CARB Executive Order DE-08-009-04.

The engine shall operate at the load level required to achieve 240 °C for a minimum of 40% of the engine's operating time and a NOx/PM ratio of 15 @ ≥ 300 °C and 20 @ ≤ 300 °C. The NOx/PM ratio shall be at least 8 with a preference for 20 or higher.

The engine shall not operate below passive regeneration temperature for more than 720 consecutive minutes. Regeneration is required after 24 consecutive cold starts and 30-minute idle sessions.

Filter cleaning is required after 150 half-hour cold starts with associated regeneration or 1,000 hours of emergency use. The CRTdm, which monitors engine exhaust back pressure and temperature will determine the actual cleaning interval and provide an alert when filter cleaning is required.

The operator shall keep records of any corrective action taken after the CRTdm has notified the operator that a high pressure limit is reached.

[Rule 1470, Rule 1303-BACT]

[Rule 1470, Rule 1304-Excemptions, Rule 1303(b)-Offset]

[Devices subject to this condition: D116]

I298.1 This equipment shall not be operated unless the facility holds 177,809 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 167,272 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[Rule 2005]

[Devices subject to this condition: D96]

I298.2 This equipment shall not be operated unless the facility holds 74,745 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 69,259 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[Rule 2005]

[Devices subject to this condition: D104]

I298.3 This equipment shall not be operated unless the facility holds 74,745 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 69,259 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[Rule 2005]

[Devices subject to this condition: D110]

I298.4 This equipment shall not be operated unless the facility holds 1,477 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 1,477 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[Rule 2005]

[Devices subject to this condition: D116]

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

Source test results shall be submitted to the District no later than 90 days after the source 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 and in terms of lbs/MMBtu.

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, Rule 1703]

[Device subject to this condition: D96, D104, D110]

K67.4 The operator shall keep a log of engine operations documenting the total time the engine is operated each month and the specific reason for operation as.

A. Emergency Use
B. Maintenance and Testing
C. Other (be specific)

In addition, for each time the engine is manually started, the log shall include the date of engine operation, the specific reason for operation, and the totalizing hour meter reading (in hours and tenths of hours) at the beginning and the end of the operation. on or before January 15th of each year, the operator shall record in the engine operating log:

A. The total hours of engine operation for the previous calendar year,
B. The total hours of engine operation for maintenance and testing for the previous calendar year

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

[Rule 1470, Rule 1304-Exemptions]

[Devices subject to this condition: D116]

K67.5 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]

[Device subject to this condition: D96, D104, D110]

<u>Device Conditions of Boiler #1</u>

A99.1 The 500 ppmv CO emission limit shall not apply when the boiler load is below 40MW.

[Rule 1303(b)(2)-Offset, 5-10-1996]

[Device Subject to this condition: D20, D24]

A195.3 The 5 ppmv NOx emission limit(s) is averaged over 720 operating hours (heat input weighted average)

The average shall be calculated based on emissions during all boilers operating hours except 1) startups defined as whenever the unit is being brought up to normal operating temperature from an inactive status, and the exhaust temperature entering the SCR catalyst is less than 450 degrees F, 2) shutdowns, defined as whenever the unit is allowed to cool from a normal operating temperature to inactive status, and the exhaust temperature entering the SCR catalyst is less 450 degrees F, 3) calibration and maintenance periods, Part 75 linearity testing, RATA testing, equipment breakdown periods as defined in Rule 2004, and periods of zero fuel flow.

The heat input weighted average NOx concentration shall be calculated using the following equation, or other equivalent equation:

PPMV(3%O2) = (Et/Qt)*K; where PPMV(3%O2) = the concentration of NOx in PPMV at 3%O2; K = a conversion factor from lbs/MMBtu to PPM, which can be determined using EPA 40 CFR60 Method 19. The default K value is 819; Et = Total reported NOx emissions during the averaging period including emissions reported as a result of missing data procedures pursuant to Rule 2012; Qt = Total heat input during the averaging period.

[Rule 2009, 5-11-2001]

[Device Subject to this condition: D20, D24]

B61.2 The operator shall not use digester gas containing the following specified compounds:

Compounds	ppm by volume
Sulfur compounds calculated as H2S greater than	40
Sulfur compounds calculated as H2S greater than	500

The operator shall meet a daily average limit of 40 ppm OR meet a monthly average limit of 40 ppm AND a 15 minute average limit of 500 ppm.

[Rule 431.1, 6-12-1998]

[Device Subject to this condition: D20, D24]

C1.5 The operator shall limit the fuel usage to no more than 688,000 cubic feet per hour.

For the purpose of this condition, fuel usage shall be defined as the burning of digester gas. The limit shall be based on the total combined limit for equipment D20 and D24.

[Rule 1303(b)(2)-Offset, 5-10-1996]

[Device Subject to this condition: D20, D24]

C1.7 The operator shall limit the operating time to no more than 2 hours in any one day.

The purpose of this condition is to insure that there is no increase in PM10 emissions requiring BACT. The condition shall only apply when the equipment is firing fuel oil. The condition shall not apply during Force Majeure Natural Gas Curtailment as defined in Rule 1135.

[Rule 1303(a)(1)-BACT, 5-10-1996]

[Device Subject to this condition: D24]

D28.2 The operator shall conduct source tests in accordance with the following specifications:

The test shall be conducted annually.

The test shall be conducted to determine the CO emissions at the outlet.

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

The test shall be conducted when the equipment is operating under normal conditions. No test shall be required in any one year for which the equipment is not in operation.

The test shall be conducted to determine compliance with the CO emissions by either: (a) conducting a source test using District method 100.1 measured over a 30 minute averaging time period, or (b) using a portable analyzer and a District-approved test method.

[Rule 3004(a)(4) – Periodic Monitoring, 8-11-1995]

<u>D29.4 The operator shall conduct source test(s) for the pollutant(s) identified below.</u>

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
PM10 emissions	Approved District Method	District Approved Avg. Time	Outlet of the SCR

The test shall be conducted after District approval of the source test protocol, but no later than the later of 180 days after the de-rate project. 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 compliance with the BACT emission limits. NOx and CO concentrations shall be corrected to 3% excess O2, dry. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, oxygen level in the flue gas. The steam turbine generator output in MW shall also be recorded.

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

The test shall be conducted when this equipment is operating at loads of 100 and 75 percent of maximum load.

The test shall be conducted with gaseous fuel only.

Test results shall be submitted to AQMD with 90 days of the completion of the tests.

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

[Device subject to this condition: D24]

D371.1 The operator shall conduct an inspection for visible emissions from all stacks and other emissions points of this equipment whenever this equipment has combusted one million gallons of diesel fuel, to be counted cumulatively over a five year period. The inspection shall be conducted while the equipment is in operation and during daylight hours. If any visible emissions (not including condensed water vapor) are detected, the operator shall:

Have a CARB-certified smoke reader determine compliance with the opacity standard, using EPA Method 9 or the procedures in the CARB manual “Visible Emission Evaluation”, within 3 working days (or during the next fuel oil firing period if the unit ceases firing on fuel oil within the three working day time frame) and report any deviations to AQMD.

In addition, the operator shall keep the records in accordance with the record keeping requirements in Section K of this permit and the following records:

a). Stack or emission point identification;
b). Description of any corrective actions taken to abate visible emissions;

c). Date and time visible emission was abated; and
d). Visible emission observation record by a certified smoke reader

[Rule 3004 – Periodic Monitoring, 8-11-1995]

[Device Subject to this condition: D20, D24]

E193.1 The operator shall construct, operate, and maintain this equipment according to the following specifications:

In compliance with all mitigation measures as stipulated in the Environmental Impact Report (SCH No. 2000101008) dated November, 2000 pertaining to the Scattergood SCR project.

[Rule 1304 – Offset Exemption]

[Device Subject to this condition: D20, D22, D24]

E193.8 The operator shall construct, operate, and maintain this equipment according to the following specifications:

<u>The operator shall limit the fuel usage of this device to no more than 1,134 MMBtu in any one hour at all time. The operator shall limit the power generation from this device to no more than 120.7 gross megawatts at all time.</u>

<u>To demonstrate compliance with this condition the operator shall install and maintain a monitoring and recording device for fuel usage in MMBtu/hr and gross power output in MW.</u>

<u>Records of fuel usage and power generation in gross megawatts shall be kept on site for a minimum of five years. The records shall be available to AQMD personnel upon request.</u>

[Rule 1304 – Offset Exemption]

[Device Subject to this condition: D24]

<u>K40.3 The operator shall provide to the District a source test report in accordance with the following specifications:</u>

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 rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

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

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

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005, Rule 1703]

[Device subject to this condition: D24]

APPENDIX A CCGS CRITERIA POLLUTANT EMISSIONS

1. EMISSIONS FROM STARTUPS

The startup process is between when the gas turbine starts and when it reaches the designated operation load and achieves compliance with the emission limits. During this process the SCR and the oxidation catalyst are not fully operational until their temperatures reach the operating temperature windows. Because of the nature of combined cycle systems, startup may be categorized as either a cold startup or a non-cold startup. The cold startup is defined as a start after a shutdown lasting for more than 72 hours. Otherwise, it is a non-cold startup. A cold startup may take much longer than a non-cold startup.

Cold startups

GE provided the following parameters and emissions rates of a cold startup.

Cold startup duration: 166 minutes
Heat input: 4,939 MMBtu in LHV
LHV: 916.4 Btu/scf
Fuel usage: 5.3896 MMscf

Table A-1 Cold Startup Emissions

Event	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)[1]
Cold startup	111	376	20	30	3.234

1 SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 5.3896 mmscf.

Non-cold startups

GE provided the following parameters and emissions rates of a non-cold startup.

Non-cold startup duration: 88 minutes
Heat input: 2,615 MMBtu in LHV
LHV: 916.4 Btu/scf
Fuel usage: 2.8536 MMscf

Table A-2 Non-cold Startup Emissions

Event	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)[1]
Non-cold startup	50	213	7	16	1.712

1 SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 2.8536 mmscf.

2. EMISSIONS FROM SHUTDOWNS

Shutdown is the process of bringing down the load of the CTG to zero. According to GE the shutdown may take 25 minutes in the ideal situation.

GE provided the following parameters and emissions rates of a shutdown process.

Shutdown duration:	25 minutes
Heat input:	313 MMBtu in LHV
LHV:	916.4 Btu/scf
Fuel usage:	0.3416 MMscf

Table A-3 Shutdown Emissions

Event	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs) [1]
Shutdown	25	114	11.3	4.5	0.205

1 SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 0.3416 mmscf.

3. EMISSIONS FROM BASE LOAD OPERATION

Base load operation is when the CTG reaches its generating capacity and when the emissions are subject to BACT limits. The emission limits are:

NOx = 2.0 ppmv at 15% O_2, dry
CO = 2.0 ppmv at 15% O_2, dry
VOC = 2.0 ppmv at 15% O_2, dry
NH3 = 5.0 ppmv at 15% O_2, dry

Particulate matter and SOx emissions are calculated using:

PM10 = 10 lbs/hr
SOx = 0.6 lbs/MMscf

The applicant calculated emissions from base load operation at three ambient temperatures, 23 °F, 63 °F, and 83 °F. These temperatures represent the coldest, average, and hottest monthly average ambient temperatures at the facility location. The calculations assume that the inlet evaporative cooling is off at 23 °F, and on at 63 °F and 83 °F. The results indicate that the highest amount of emissions occur when operating at ambient temperature of 63 °F. Thus, the results of 63 °F are selected for potential to emit (PTE) determinations.

At 63 °F the GE 7FA combustion gas turbine has the following fuel parameters:

Heat Input:	1,875.1 MMBtu/hr, LHV
	2,080.9 MMBtu/hr, HHV
Fuel Flow:	2.046 MMscf/hr
LHV:	916.4 Btu/scf
HHV:	1,017 Btu/scf
Exhaust:	1,157,900 ACFM
Water Content:	9%
Oxygen Content, dry:	13.4%
Exhaust Temperature:	200 °F, or 366 °K

The exhaust flow rate is converted to standard conditions, dry, and with 15% O_2. The standard condition is defined as 15 °C, or 288 °K.

1,157,900 * 288 / 366 = 911,100 scfm, wet
911,100 * (1-9%) = 829,100 scfm, dry
829,100 * (20.9%- 13.4%)/(20.9%-15%) = 1,054,000 scfm, dry @ 15% O_2
1,054,000 * 60 = 63.24 MMscfh, dry @ 15% O_2

Concentration factors are converted to mass emission factors using the following equations:

Mass emissions in lb-mole/hr = Concentration * Exhaust / 379.5 scf/lb-mole
Mass emissions in lb/hr = lb-mole/hr * molecular weight

The next table shows the mass emission rates.

Table A-4 Base Load Operation Emissions

	NOx	CO	VOC	PM	SOx	NH3
Concentration in ppmv	2.0	2.0	2.0			5.0
Molecular Weight	46	28	16			17
Mass in lb-moles/hr	0.333	0.333	0.333			0.833
Mass in lb/hr	15.32	9.32	5.33	10	1.23	14.16
Mass in lb/mmscf	7.49	4.56	2.61	4.89	0.6	6.92

4. EMISSIONS FROM COMMISSIONING

Process Description

The combustion turbine generators must first be commissioned to the desired performance before they begin commercial service. The commissioning is a dedicated process that is mandated by the turbine manufacturer. GE provided a 24-day multi-step commissioning process for the 7FA gas turbine. GE estimates that it will take 460 hours to accomplish the commissioning.

The following table describes the commissioning process.

Table A-5 Commissioning Schedule

Task	Duration (hr)	CT Load (kW)	Fuel Rate (MMBtu/hr, LHV)	Fuel Usage (MMBtu, LHV)	SCR (Y/N)
Full Speed No Load (FSNL)	4	0	417	1,667	N
First Fire/Synch	15	23,100	579	8,691	N
Steam Blows	96	41,580	710	68,118	N
Initial CT Tuning	16	231,000	2,044	32,704	N
SCR Ammonia System Commissioning	18	231,000	2,044	36,793	Y
CT Integrated Tuning	29	231,000	2,044	59,277	Y

Achieve Water Chemistry, Roll/Synch ST	22	231,000	2,044	44,969	Y
Plant Tuning	148	23,100-231,000	204-2,044	186,808	Y
Emission Test/RATA	12	231,000	2,044	24,528	Y
Performance Test	28	231,000	2,044	57,233	Y
72-hr Reliability Test	72	231,000	2,044	147,170	Y

Emissions Calculations

Emissions of the commissioning process are either provided by GE, or calculated using the following emission factors:

NOx: 2 ppmv with the SCR on, 9 ppmv with the SCR off
CO: 2 ppmv
VOC: 2 ppmv
PM10: 0.006 lbs/MMBtu
SOx: 0.25 grain per 100 scf

The following table shows detailed emissions of each process.

Table A-6 GE 7FA Commissioning Emissions

Day	Task	Hours	Fuel Usage (MMBtu)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)
1	FSNL	4	1,667	480	2,560	220	40	1.30
2	First Fire	15	8,691	3,750	3,150	150	150	6.77
3	Steam Blow	24	17,029	2,263	94,204	2,042	240	13.26
4	Steam Blow	24	17,029	2,280	96,000	2,080	240	13.26
5	Steam Blow	24	17,029	2,280	96,000	2,080	240	13.26
6	Steam Blow	24	17,029	2,265	94,447	2,055	240	13.26
7	CT Initial Tuning	16	32,704	1,354	594	71	161	25.46
8	SCR NH3 Commissioning	18	36,793	378	459	68	181	28.65
9	CT Integrated Tuning	17	34,749	359	450	65	171	27.06

10	CT Integrated Tuning	12	24,528	265	409	50	121	19.10
11	Water Chem.	22	44,969	454	492	80	221	35.01
12	Plant Tuning	14	8,111	782	929	147	141	6.32
13	Plant Tuning	14	11,529	361	11,948	734	141	8.98
14	Plant Tuning	24	19,764	594	20,837	1,282	241	15.39
15	Plant Tuning	24	29,528	304	133	52	240	22.99
16	Plant Tuning	24	29,528	304	133	52	240	22.99
17	Plant Tuning	24	39,292	379	165	62	240	30.59
18	Plant Tuning	24	49,057	453	197	72	240	38.20
19	Emissions Test	12	24,528	265	409	50	121	19.10
20	Performance Test	14	28,616	303	426	56	141	22.28
21	Performance Test	14	28,616	303	426	56	141	22.28
22	72-hr Test	24	49,057	453	197	72	240	38.20
23	72-hr Test	24	49,057	453	197	72	240	38.20
24	72-hr Test	24	49,057	453	197	72	240	38.20
Total		460	667,957	21,535	424,959	11,740	4,611	520

(1) Emissions of this process are provided by GE

The total fuel usage is:

667,957 MMBtu / 916.4 Btu/scf = 728.892 MMscf

The average emission factors during the commissioning is calculated in the next table.

Table A-7 Emission Factors – Commissioning

	NOx	CO	VOC	PM10	SOx
Emission Factor (lb/MMscf)	29.54	583.02	16.11	6.32	0.71

In accordance with RECLAIM rules the NOx emission factor of 29.54 lb/mmscf will be used to report NOx emissions during the commissioning period.

5. MAXIMUM DAILY EMISSIONS

During normal operation the maximum daily emissions can be calculated by assuming the gas turbine has one cold startup lasting 166 minutes (2.77 hours), one non-cold startup, two shutdowns, and continued operation at 100% load for the remaining 18.93 hours of a day. The emissions are calculated and shown in the next table.

Table A-8 Maximum Daily Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx
1 Cold startup emissions (lbs)	111	376	20	30	3.234
1 Non-cold startup emissions (lbs)	50	213	7	16	1.712
2 Shutdown emissions (lbs)	50	228	22.6	9	0.41
Emission factor – normal operation (lb/hr)	15.32	9.32	5.33	10.0	1.23
Normal operation emissions for 18.93 hours (lbs)	290	176	101	189	23
Daily total (lbs)	501	993	151	244	29

For ammonia the maximum daily emissions occur when the gas turbine is operating at 100% base load for 24 hours a day.

NH_3 = 24 * 14.16 = 340 lbs/day

6. MONTHLY EMISSIONS

The following hypothetical monthly operating schedule is proposed:

Monthly schedule: 31 days, base load operation that includes 5 cold startups, 57 non-cold startups, 62 shutdowns, 0.5 hour non-operational between two daily starts.

Excluding the startups and shutdowns the base load operation duration is:

(31*24*60 – 5*166 -57*88 -62*25)/60 – 31*0.5= 605.23 hours

Emissions generated from this operating scheduled is calculated and presented in the next table.

Table A-9 Monthly Total Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Cold startups – 5 times (lbs)	555	1,880	100	150	16	0
Non-cold startups -57 times (lbs)	2,850	12,141	399	912	98	0
Shutdowns – 62 times (lbs)	1,550	7,068	700.6	279	13	0
Base load operation (lbs)	9,272	5,641	3,226	6,052	744	8,570
Monthly total (lbs)	14,227	26,730	4,425	7,393	871	8,570

Total fuel consumption in a month is:

$$5*5.3896 + 57*2.8536 + 62*0.3416 + 605.23*2.046 = 1,449.1 \text{ MMscf}$$

The equivalent emission factors are:

Table A-10 Average Emission Factors – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Average Emission Factor (lbs/mmscf)	9.82	18.45	3.05	5.10	0.60	5.91

The First Month

The first month of operation includes commissioning. It is assumed that the operation comprises 24 days of commissioning and 7 days of base load operation.

The emissions from the 7 days of base load operation is assumed to be 7/31 of the monthly base load operation total in Table A-8.

Table A-11 1st Month Total Emissions

	NOx	CO	VOC	PM10	SOx
Commissioning – 24 days (lbs)	21,535	424,959	11,740	4,611	520
Base load, 7 days (lbs)	3,213	6,036	999	1,669	197
Monthly total (lbs)	24,748	430,995	12,739	6,280	717

Total fuel consumption is:

728.892 + 7/31 *1,449.1 = 1,056.1 MMscf

The equivalent emission factors are:

Table A-12 Average Emission Factors – 1st Month

	NOx	CO	VOC	PM10	SOx
Average Emission Factor (lbs/mmscf)	23.43	408.1	12.06	5.95	0.68

7. YEARLY EMISSIONS

The following annual operating schedule is proposed:

Annual schedule: 8,760 hours, base load operation that includes 53 cold startups, 677 non-cold startups, 730 shutdowns, 0.5 hour non-operational between two daily starts.

Excluding the startups, shutdowns and the non-operational time the base load operation duration is:

8,760 - 53*166/60 - 677*88/60 - 730*25/60 – 365*0.5= 7,133.77 hours

Emissions generated from this operating scheduled is calculated and presented in the next table.

Table A-13 Annual Emissions – Base Load Operation

	NOx	CO	VOC	PM10	SOx	NH3
Cold startups – 53 events (lbs)	5,883	199,28	1,060	1,590	171	0
Non-cold startups - 677 events (lbs)	33,850	144,201	4,739	10,832	1,159	0
Shutdowns – 730 events (lbs)	18,250	83,220	8,249	3,285	150	0
Base load operation – 7133.77 hours (lbs)	109,289	66,487	38,023	71,338	8,775	101,014
Total (lbs)	167,272	313,836	52,071	87,045	10,255	101,014
Total (tons/year)	83.6	156.9	26.0	43.5	5.1	50.5

Annual fuel usage of the above operation schedule:

53*5.3896 +677*2.8536 +730*0.3416 +7133.77*2.046 = 17,026.6 mmscf

<u>First year operation</u>

The first year includes the commissioning process. It includes 24 days of commissioning and 341 days of base load operation. The emissions from the 341 days of base load operation is assumed to be 341/365 of the annual emissions calculated in Table A-12.

Table A-14 First Year Emissions

	NOx	CO	VOC	PM10	SOx
Commissioning – 24 days (lbs)	21,535	424,959	11,740	4,611	520
Base load, 341 days (lbs)	156,274	293,200	48,647	81,321	9,580

Total (lbs)	177,809	718,159	60,387	85,932	10,100

8. EMISSIONS DURING THE INTERIM PERIOD

The interim period is defined as a period up to one year from the start of operation until the NOx CEMS is certified. Even though the NOx CEMS is not yet certified during the interim period, it is believed that after commissioning the SCR would be operating properly. Therefore, the NOx emissions are calculated based on 2.0 ppmv.

The emission factor is calculated by using the annual operational average of Table A-13. Fuel usage after the commissioning period is:

Fuel = 17,026.6 * 341/365 = 15,907.04 mmscf

The effective emission factor for the interim period, not including the commissioning period, is:

NOx = 156,274/15,907.04 = 9.82 lbs/mmscf

9. POTENTIAL TO EMIT AND RTC REQUIREMENT

The potential to emit (PTE) is calculated based on the 30-day average of the highest monthly emissions. According to the results of Tables A-8 and A-10 the highest monthly emissions of NOx, CO, and VOC are generated during the first month of operation. The highest monthly emissions of PM and SOx are generated during 100% base load operation. Thus, they are selected as the PTE for the GE 7FA generator.

Table A-15 CCGS PTE of Criteria Pollutants

	NOx	CO	VOC	PM10	SOx
Highest Monthly Total (lbs/month)	24,748	430,995	12,739	7,393	871
30-Day Average (lbs/day)	825	14,367	425	246	29

The RECLAIM Trading Credits (RTC) requirement is calculated based on annual NOx emissions. As determined in Tables A-12 and A-13 the first year requirement is 177,809 lbs and the years after the first year is 167,272 lbs.

APPENDIX B SCGS CRITERIA POLLUTANTS EMISSIONS

1. EMISSIONS FROM STARTUPS

The startup process is between when the gas turbine starts and when it reaches the designated operation load and achieves compliance with the emission limits. During this process the SCR and the oxidation catalyst are not fully operational until their temperatures reach the operating temperature windows. LADWP has specified that the startup process will take 25 minutes. During the first eight minutes NOx levels are in the 50-100 ppmvd range and CO levels are in the 100-500 ppmvd levels. Water injection is introduced at the 8th minute and NOx levels reach 25 ppmvd by the 10th minute. From the 10th minutes on and during the next 15 minutes the SCR and the oxidation catalyst become more effective, bringing the NOx levels to 2.5 ppmvd and the CO levels to 4 ppmvd.

GE provided the following parameters and emissions rates of a startup.

Startup duration:	25 minutes
Heat input:	310.1 MMBtu in HHV
HHV:	1,017 Btu/scf
Fuel usage:	0.305 MMscf

Table B-1 Startup Emissions – Each Turbine

Event	NOx (lbs)[1]	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)[2]
Startup	20	10.4	0.9	2.7	0.183

1 GE datasheet shows 16.6 lbs per startup. LADWP revised to 20 lbs per startup.
2 SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 0.305 mmscf.

2. EMISSIONS FROM SHUT DOWN

The shutdown is the process of reducing the CTG load to zero. It typically takes 10.3 minutes to conduct a shutdown process for a GE LMS100 gas turbine.

GE provided the following parameters and emission factors.

Startup duration:	10.3 minutes
Heat input:	55.9 MMBtu in HHV
HHV:	1,017 Btu/scf
Fuel usage:	0.055 MMscf

Table B-2 Shutdown Emissions – Each Turbine

Event	NOx (lbs)[1]	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)[2]
Shutdown	3	0.5	0.3	1.1	0.033

1 GE datasheet shows 0.5 lbs per shutdown. LADWP revised to 3 lbs per shutdown.
2 SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 0.055 mmscf.

3. EMISSIONS FROM BASE LOAD OPERATION

Base load operation is when the CTG reaches its generating capacity and when the emissions are subject to BACT limits. The emission limits are:

NOx = 2.5 ppmv at 15% O_2, dry
CO = 4.0 ppmv at 15% O_2, dry
VOC = 2.0 ppmv at 15% O_2, dry
NH3 = 5.0 ppmv at 15% O_2, dry

Particulate matter and SOx emissions are calculated using:

PM10 = 5.7 lbs/hr
SOx = 0.6 lbs/MMscf

The applicant calculated emissions from normal operation at three ambient temperatures, 23 °F, 63 °F, and 83 °F. These temperatures represent the coldest, average, and hottest monthly average ambient temperatures at the facility location. The calculations assume that the inlet evaporative cooling is off at 23 °F, and on at 63 °F and 83 °F. The results indicate that the highest amount of emissions occur when operating at ambient temperature of 63 °F. Thus, the results of 63 °F are selected for potential to emit (PTE) determinations.

At 63 °F the GE LMS100 combustion gas turbine has the following fuel parameters:

Heat Input: 814.7 MMBtu/hr, LHV
Fuel Flow: 0.889 MMscf/hr
Exhaust: 1,766,246 lb/hr
Exhaust Molecular Weight: 28.12
Exhaust Water Content: 10.97%
Exhaust Oxygen Content, wet: 11.85%
Exhaust Temperature: 766 °F, or 366 °K

The exhaust mass flow rate is converted to at standard conditions, dry, and with 15% excess oxygen. The standard condition is defined at 15 °C, or 288 °K.

1,766,246 /28.12 * 379.5 = 23.837 MMscf/hr, wet
23.837 * (1-10.97%) = 21.222 MMscf/hr, dry

Oxygen content in exhaust, dry:

11.85% * 23.837 /21.222 = 13.31%

Exhaust flow rate dry, @ 15% O_2

21.222 * (20.9%- 13.31%)/(20.9%-15%) = 27.30 MMscf/hr

Concentration factors are converted to mass emission factors using the following equations:

Mass emissions in lb-mole/hr = Concentration * Exhaust / 379.5 scf/lb-mole
Mass emissions in lb/hr = lb-mole/hr * molecular weight

The next table shows the mass emission rates.

Table B-3 Base Load Operation Emissions – Each Turbine

	NOx	CO	VOC	PM	SOx	NH3
Concentration in ppmv	2.5	4.0	2.0			5.0
Molecular Weight	46	28	16			17
Mass in lb-moles/hr	0.18	0.288	0.144			0.36
Mass in lb/hr	8.28	8.06	2.30	5.7	0.533	6.12
Mass in lb/mmscf	9.31	9.07	2.59	6.41	0.60	6.88

4. EMISSIONS FROM COMMISSIONING

Process Description

The combustion turbine generators must first be commissioned to the desired performance before they begin regular service. The commissioning is a dedicated process that is generally prescribed by the turbine manufacturer. GE provides a 7-step commissioning process for the LMS100 gas turbine. GE estimates that it will take 104 hours to accomplish the commissioning in the ideal situation. The LADWP decides to assign 152 hours for the commissioning, and add 24 hours for SCR system testing and stack/RATA testing as Steps 8 and 9. In all the commissioning will be a 9-step process, and will take 176 hours. The commissioning will be concluded in 12 days.

The following table describes the commissioning process.

Table B-4 GE LMS100 Turbine Commissioning Schedule

	Description	Duration	SCR Status
Step 1	Checking and inspection, unfired	Day 1	Off
Step 2	First fire and shutdown to check leaks	Day 1, 23 hours	Off
Step 3	Synch and check Emergency-stop	Day 2, 17 hours	Off
Step 4	Automatic Voltage Regulator (AVR) commissioning	Day 3, 17 hours	Off
Step 5	Break-in run	Day 4, 12 hours	Off
Step 6	Dynamic commissioning of AVR	Days 5-9, 60 hours	Off
Step 7	Base load AVR commissioning	Day 10, 23 hours	Off
Step 8	SCR testing	Day 11, 12 hours	On
Step 9	Stack/RATA testing	Day 12, 12 hours	On

Emissions Calculations

Emissions of the commissioning process are either provided by GE, or calculated using the following emission factors:

With the SCR off:

PM10: 0.0066 lbs/MMBtu (HHV), or 6.712 lb/MMscf
SOx: 0.6 lbs/MMscf

With the SCR on:

PM10: 0.0075 lbs/MMBtu (HHV), or 7.628 lb/MMscf, due to SO_2 conversion to PM
SOx: 0.6 lbs/MMscf

The following table shows detailed emissions of each process.

Total operating hours, total fuel consumption, and total emissions are tabulated in the next table. Average emission rates are also calculated.

Table B-5 Natural Gas Commissioning Summary

	Duration (Hour)	Heat Input (MMBtu) LHV	Fuel (MMscf)	NOx[1] (lbs)	CO[1] (lbs)	VOC[1] (lbs)	PM10 (lbs)	SOx (lbs)
Step #1	0	0	0	0	0	0	0.00	0.00
Step #2	23	1,696	1.85	256	1045	27	12.42	1.11
Step #3	17	1,261	1.38	188	772	20	9.24	0.83
Step #4	17	1,587	1.73	356	514	12	11.62	1.04
Step #5	12	1,125	1.23	251	363	9	8.24	0.74
Step #6	60	29,340	32.02	2,941	4,521	288	214.90	19.21
Step #7	23	18,357	20.03	1,844	4,535	275	134.45	12.02
Step #8	12	9,578	10.45	962	2,366	143	79.73	6.27
Step #9	12	9,578	10.45	962	2,366	143	79.73	6.27
Total	176	72,522	79.14	7,760	16,482	917	550.3	47.5

1. NOx, CO, and VOC emissions are provided by GE.

The total fuel usage is:

72,522 MMBtu / 916.4 Btu/scf = 79.14 MMscf

The average emission factors during the commissioning is calculated in the next table.

Table B-6 Emission Factors – Commissioning

	NOx	CO	VOC	PM10	SOx
Emission Factor (lb/MMscf)	98.06	208.27	11.59	6.95	0.60

In accordance with RECLAIM rules the NOx emission factor of 98.06 lb/mmscf will be used to report NOx emissions during the commissioning period.

5. MAXIMUM DAILY EMISSIONS

During normal operation the maximum daily emissions can be calculated by assuming the gas turbine has four startup lasting 4*25 minutes (1.67 hours), four shutdowns lasting 4*10.3 minutes (0.79 hours), and continued operation at 100% load for the remaining 21.65 hours of a day. The emissions are calculated and shown in the next table.

Table B-7 Maximum Daily Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx
4 Startup emissions (lbs)	20	10.4	0.9	2.7	0.183
4 Shutdown emissions (lbs)	12	2	1.2	4.4	0.132
Emission factor – base load operation (lb/hr)	8.28	8.06	2.30	5.7	0.533
Emissions (lbs)– base load operation for 21.6 hours	179	174	50	123	11.5
Daily total (lbs)	271	218	59	139	12

For ammonia the maximum daily emissions occur when the gas turbine is operating at 100% base load for 24 hours a day.

NH_3 = 24 * 6.12 = 167 lbs/day

6. MONTHLY EMISSIONS

Once the gas turbine generators start commercial operation LADWP expects the units may operate continuously at full load in some days and at partial load in other days. A hypothetical monthly operating schedule is presented, assuming base load continuous operation with 4 startups and 4 shutdowns per day.

Full load continuous operation: 31 days, 24 hours per day that includes 4 startups (100 minutes total), 4 shutdowns (41.2 minutes total), and no gap between two starts

With this schedule the daily base load operation duration is 21.65 hours. The monthly total base load operation duration is 671.05 hours.

The monthly emissions are calculated and summarized in the next table.

Table B-8 Monthly Total Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Startups– 124 events (lbs)	2,480	1,290	112	335	23	0
Shutdowns – 124 events (lbs)	372	62	37	136	4	0
Base load operation – 671.05 hours (lbs)	5,556	5,409	1,543	3,825	358	4,107
Monthly total (lbs)	8,408	6,760	1,692	4,296	384	4,107

Total fuel consumption is:

124*0.305 + 124*0.055 + 671.05*0.889 = 641.2 MMscf/month

The equivalent emission factors are:

Table B-9 Emission Factors – Base Load Operation

	NOx	CO	VOC	PM10	SOx
Average Emission Factor (lbs/mmscf)	13.11	10.54	2.64	6.70	0.60

The First Month

The first month operation includes the commissioning. It is assumed that the month includes 12 days of the commissioning and 19 days of base load operation. The load factor is assumed to be 100%.

The next table calculates the monthly total emissions.

Table B-10 Monthly Emissions – First Month

	NOx	CO	VOC	PM10	SOx
Commissioning – 12 days (lbs)	7,760	16,482	917	550	47
Base load, 19 days (lbs)	5,153	4,143	1,037	2,633	236
Monthly total (lbs)	12,913	20,625	1,954	3,185	283

Fuel usage of this month:

79.14 + 19*(4*0.305+4*0.055+21.65*0.889) = 472.19 MMscf

7. YEARLY EMISSIONS

The following annual operating schedule is proposed:

Annual schedule: 5,168 hours (load factor of 59%), base load operation that includes 1,460 startups, 1,460 shutdowns.

Excluding the startups and shutdowns the base load operation duration is:

5,168 – 1,460*25/60 - 1460*10.3/60= 4,309.0 hours

Emissions generated from this operating scheduled is calculated and presented in the next table.

Table B-11 Annual Emissions – Base Load per Turbine

	NOx	CO	VOC	PM10	SOx	SOx
Startups – 1,460 events (lbs)	29,200	15,184	1,314	3,942	267	0
Shutdowns – 1,460 events (lbs)	4,380	730	438	1,606	48	0
Base load operation 4,309.0 hours (lbs)	35,679	34,731	9,911	24,561	2,297	26,371
Total (lbs)	69,259	50,645	11,663	30,109	2,612	26,371
Total (tons/year)	34.6	25.3	5.8	15.1	1.3	13.2

Fuel usage (in mmscf):

1,460*0.305 +1,460*0.055 + 4,309.0* 0.889 = 4,356.33 mmscf

First year operation

The first year includes the commissioning process. It includes 12 days of commissioning and 353 days of base load operation. A load factor of 59% is assumed for the base load operation that may have four startups and four shutdowns per day. The emissions from the 353 days of base load operation is assumed to be 353/365 of the annual emissions calculated in Table A-5.

Table B-12 First Year Emissions – Each Turbine

	NOx	CO	VOC	PM10	SOx
Commissioning – 12 days (lbs)	7,760	16,482	917	550	47
Base load, 341 days (lbs)	66,985	48,983	11,280	29,122	2,526
Total (lbs)	74,745	65,465	12,197	29,672	2,574

8. EMISSIONS DURING THE INTERIM PERIOD

The interim period is defined as a period up to one year from the start of operation until the NOx CEMS is certified. Even though the NOx CEMS is not yet certified during the interim period, it is believed that after commissioning the SCR would be operating properly. Therefore, the NOx emissions are calculated based on 2.5 ppmv.

The equivalent emission factor is calculated using the propose annual operating schedule. Fuel usage after the commissioning period is:

Fuel = 4,356.33 * 353/365 = 4213.11 mmscf

The effective emission factor for the interim period, not including the commissioning period, is:

NOx = 66,985/4,213.11 = 15.9 lbs/mmscf

9. POTENTIAL TO EMIT AND RTC REQUIREMENT

The potential to emit (PTE) is calculated based on the 30-day average of the highest monthly emissions. According to the results of Tables B-7 and B-9 the highest monthly emissions of NOx, CO, and VOC are generated during the first month of operation. The highest monthly emissions of PM and SOx are generated during 100% base load operation. Thus, they are selected as the PTE for the GE LMS100 generator.

Table B-13 SCGS PTE – Each Turbine

	NOx	CO	VOC	PM10	SOx
Highest Monthly Total (lbs/month)	12,913	20,625	1,954	4,296	384
30-Day Average (lbs/day)	430	688	65	143	13

The RECLAIM Trading Credits (RTC) requirement is calculated based on annual NOx emissions. As determined in Tables B-10 and B-11 the first year requirement of each of the SCGS turbine is 74,745 lbs and the years after the first year is 69,262 lbs.

APPENDIX C AUXILIARY EQUIPMENT EMISSIONS

1. Standby Generators

The project includes a diesel fueled standby generator engine. The following specifications are used in emission calculations:

Engine Manufacturer	Caterpillar
Engine Model Number	3516C DITA
Engine brake horsepower (BHP)	3,622
Engine Power Output (KW)	2,500
Fuel:	#2 CARB Diesel
Fuel Usage (Gallons/hour):	173.3
Annual Operation Limit (hours):	200
Annual Maintenance Limit (hours):	50
Fuel Usage per year (Mgal/year):	8.665

The following emission factors are proposed by the applicant and warranted by the manufacturer.

NOx (grams/bhp-hr)	3.7	
CO (grams/bhp-hr)	0.67	
VOC (grams/bhp-hr)	0.25	
PM (grams/bhp-hr)	0.07	before the particulate filter
	0.01	after the diesel particulate filter

SOx emission factor is extrapolated by assuming the CARB diesel contains less than 15 ppm sulfur as H_2S. One pound of H_2S would convert to 64/34 pounds of SO_2 or SOx.

SOx (lb/lb diesel)	$28.2 * 10^{-6}$
SOx (lb/Mgal)	$28.2 * 10^{-6} * 1000 * 7.5 = 0.21$

The equivalent hourly emission rates are:

NOx = 3,622 * 3.7/453.6 = 29.54 lb/hour
CO = 3,622 *0.67/453.6 = 5.35 lb/hour
VOC = 3,622 * 0.25/453.6 =2.00 lb/hour
PM = 3,622*0.01/453.6 = 0.08 lb/hour
SOx = 0.21*173.3/1,000 = 0.04 lb/hour

Emission increases are then calculated by assuming 50 hours of annual maintenance, or 4.2 hours per month. Daily maximum is calculated by assuming the engine will operate for one hour per day. Annual emissions are calculated based on 50 hours per year.

Table C-1 Emissions of the Standby Generator

	NOx	CO	VOC	PM	SOx
Hourly (lbs/hour)	29.54	5.35	2.0	0.08	0.04
Daily Maximum (lbs)	30	5	2.0	0	0
Monthly Total (lbs)	124	22	8	0	0
Yearly Total (lbs)	1,477	268	100	4	2
Emission Increase (lbs/day)	4.1	0.7	0.3	0	0

The standby generator is considered as a RECLAIM process unit. According to Rule 2002 the reporting factor is equivalent to the permitted BACT limit:

NOx = 29.54/0.1733 = 170.5 lbs/Mgal

Thus, for RECLAIM emission reporting purposes the annual NOx emissions are:

NOx = 170.5 lb/1000 gal* 173.3 gal/hour * 50 hours = 1,477 lbs

2. Oil Water Separators

The project includes two identically sized oil water separators. The specifications of the oil water separators are:

Type:	Horizontally placed cylindrical above ground
Count:	2
Tank diameter:	6.00 ft
Tank length:	23.25 ft
Volume:	5,000 gallons

Annual turnovers:	52
Vacuum setting:	no vent valve
Pressure setting:	no vent valve

Working loss and breathing loss are expected from the oil water separators. The emissions are considered as VOC, and are calculated using EPA's Tank program. The detailed calculation spreadsheets are included in the application folder. The results are summarized below:

Annual Breathing Loss:	0 lbs
Annual Working Loss:	13.17 lbs
Total Loss:	13.17 lbs/year

The monthly average is 1.1 lbs/month. The 30-day average emissions are 0.04 lbs/day.

APPENDIX D TAC and HAP EMISSIONS

In addition to criteria pollutants emissions the equipment are expected to generate hazardous air pollutants (HAP) emissions. The HAP emissions are subject to the federal NESHAP regulation. Some of the HAP pollutants are considered toxic air contaminants (TAC). The TAC emissions are subject to the AQMD Rule 1401.

1. CCGS

HAP and TAC emissions are calculated under a variety of operating parameters. The following operating scenario generates the highest amount of HAP and TAC emissions.:

Annual hours of operation:	8,760 hours
Ambient temperature:	63 °F
Load Factor:	100% base load
Fuel flow rate:	2.046 MMscf/hr
Annual total fuel usage:	17,923 MMscf/year

The TAC and HAP emissions are calculated in the next two tables.

Table D-1 TAC Emissions – CCGS

TAC Pollutants	Aix Toxic Case Number	Emission Factor (lb/MMscf)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
Ammonia	7664417	NA	1.42E+01	6.20E+01
1,3-Butadiene	106990	4.37E-04	8.94E-04	3.92E-03
Acetaldehyde	75070	4.07E-02	8.33E-02	3.65E-01
Acrolein	107028	3.68E-03	7.53E-03	3.30E-02
Benzene	71432	3.32E-03	6.79E-03	2.98E-02
Ethylbenzene	100414	3.25E-02	6.65E-02	2.91E-01
Formaldehyde	50000	3.66E-01	7.49E-01	3.28E+00
Propylene Oxide	75569	2.95E-02	6.04E-02	2.64E-01
Toluene	108883	1.32E-01	2.70E-01	1.18E+00
Xylenes	1330207	6.51E-02	1.33E-01	5.83E-01
Benzo(a)anthracene	56556	2.26E-05	4.62E-05	2.03E-04
Benzo(a)pyrene	50328	1.39E-05	2.84E-05	1.25E-04

Benzo(b)fluoranthene	205992	1.13E-05	2.31E-05	1.01E-04
Benzo(k)fluoranthene	207089	1.10E-05	2.25E-05	9.86E-05
Chrysene	218019	2.52E-05	5.16E-05	2.26E-04
Diebenz(a,h)anthracene	53703	2.35E-05	4.81E-05	2.11E-04
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	4.81E-05	2.11E-04
Naphthalene	91203	1.66E-03	3.40E-03	1.49E-02
			Total TAC emissions per year	6.81E+01

Table D-2 HAP Emissions – CCGS

HAP Pollutants	Aix Toxic Case Number	Emission Factor (lb/MMscf)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
1,3-Butadiene	106990	4.37E-04	8.94E-04	3.92E-03
Acetaldehyde	75070	4.07E-02	8.33E-02	3.65E-01
Acrolein	107028	3.68E-03	7.53E-03	3.30E-02
Benzene	71432	3.32E-03	6.79E-03	2.98E-02
Ethylbenzene	100414	3.25E-02	6.65E-02	2.91E-01
Formaldehyde	50000	3.66E-01	7.49E-01	3.28E+00
Propylene Oxide	75569	2.95E-02	6.04E-02	2.64E-01
Toluene	108883	1.32E-01	2.70E-01	1.18E+00
Xylenes	1330207	6.51E-02	1.33E-01	5.83E-01
Acenaphthene	83329	1.90E-05	3.89E-05	1.70E-04
Acenaphthylene	208968	1.47E-05	3.01E-05	1.32E-04
Anthracene	120127	3.38E-05	6.92E-05	3.03E-04
Benzo(a)anthracene	56556	2.26E-05	4.62E-05	2.03E-04
Benzo(a)pyrene	50328	1.39E-05	2.84E-05	1.25E-04
Benzo(b)fluoranthene	205992	1.13E-05	2.31E-05	1.01E-04
Benzo(e)pyrene	192972	5.44E-07	1.11E-06	4.86E-06
Benzo(g,h,i)perylene	191242	1.37E-05	2.80E-05	1.23E-04
Benzo(k)fluoranthene	207089	1.10E-05	2.25E-05	9.86E-05
Chrysene	218019	2.52E-05	5.16E-05	2.26E-04
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	4.81E-05	2.11E-04
Naphthalene	91203	1.66E-03	3.40E-03	1.49E-02
Diebenz(a,h)anthracene	53703	2.35E-05	4.81E-05	2.11E-04
Fluoranthene	206440	4.32E-05	8.84E-05	3.87E-04
Fluorene	86737	5.80E-05	1.19E-04	5.20E-04
Phenanthrene	85018	3.13E-04	6.40E-04	2.80E-03
Pyrene	129000	2.77E-05	5.67E-05	2.48E-04
			Total HAP emissions per year	6.05E+00

2. SCGS

HAP and TAC emissions are calculated under a variety of operating parameters. The following operating scenario generates the highest amount of HAP and TAC emissions.:

Annual hours of operation:	8,760 hours
Ambient temperature:	63 °F
Load Factor:	59% base load
Fuel flow rate:	0.889 MMscf/hr
Annual fuel usage:	4,594 MMscf/year

The TAC and HAP emissions are calculated in the next two tables.

Table D-3 TAC Emissions – SCGS

TAC Pollutants	Aix Toxic Case Number	Emission Factor (lb/MMscf)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
Ammonia	7664417	NA	6.11E+00	1.58E+01
1,3-Butadiene	106990	4.37E-04	3.88E-04	1.00E-03
Acetaldehyde	75070	4.07E-02	3.62E-02	9.35E-02
Acrolein	107028	3.68E-03	3.27E-03	8.45E-03
Benzene	71432	3.32E-03	2.95E-03	7.63E-03
Ethylbenzene	100414	3.25E-02	2.89E-02	7.47E-02
Formaldehyde	50000	3.66E-01	3.25E-01	8.41E-01
Propylene Oxide	75569	2.95E-02	2.62E-02	6.78E-02
Toluene	108883	1.32E-01	1.17E-01	3.03E-01
Xylenes	1330207	6.51E-02	5.79E-02	1.50E-01
Benzo(a)anthracene	56556	2.26E-05	2.01E-05	5.19E-05
Benzo(a)pyrene	50328	1.39E-05	1.24E-05	3.19E-05
Benzo(b)fluoranthene	205992	1.13E-05	1.01E-05	2.60E-05
Benzo(k)fluoranthene	207089	1.10E-05	9.78E-06	2.53E-05
Chrysene	218019	2.52E-05	2.24E-05	5.79E-05
Diebenz(a,h)anthracene	53703	2.35E-05	2.09E-05	5.40E-05
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	2.09E-05	5.40E-05
Naphthalene	91203	1.66E-03	1.48E-03	3.81E-03
			Total TAC emissions per year	1.74E+01

Table D-4 HAP Emissions – SCGS

HAP Pollutants	Aix Toxic Case Number	Emission Factor (lb/MMscf)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
1,3-Butadiene	106990	4.37E-04	3.88E-04	1.00E-03
Acetaldehyde	75070	4.07E-02	3.62E-02	9.35E-02
Acrolein	107028	3.68E-03	3.27E-03	8.45E-03
Benzene	71432	3.32E-03	2.95E-03	7.63E-03
Ethylbenzene	100414	3.25E-02	2.89E-02	7.47E-02
Formaldehyde	50000	3.66E-01	3.25E-01	8.41E-01
Propylene Oxide	75569	2.95E-02	2.62E-02	6.78E-02
Toluene	108883	1.32E-01	1.17E-01	3.03E-01
Xylenes	1330207	6.51E-02	5.79E-02	1.50E-01
Acenaphthene	83329	1.90E-05	1.69E-05	4.36E-05
Acenaphthylene	208968	1.47E-05	1.31E-05	3.38E-05
Anthracene	120127	3.38E-05	3.01E-05	7.77E-05
Benzo(a)anthracene	56556	2.26E-05	2.01E-05	5.19E-05
Benzo(a)pyrene	50328	1.39E-05	1.24E-05	3.19E-05
Benzo(b)fluoranthene	205992	1.13E-05	1.01E-05	2.60E-05
Benzo(e)pyrene	192972	5.44E-07	4.80E-07	1.24E-06
Benzo(g,h,i)perylene	191242	1.37E-05	1.22E-05	3.15E-05
Benzo(k)fluoranthene	207089	1.10E-05	9.78E-06	2.53E-05
Chrysene	218019	2.52E-05	2.24E-05	5.79E-05
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	2.09E-05	5.40E-05
Naphthalene	91203	1.66E-03	1.48E-03	3.81E-03
Diebenz(a,h)anthracene	53703	2.35E-05	2.09E-05	5.40E-05
Fluoranthene	206440	4.32E-05	3.84E-05	9.92E-05
Fluorene	86737	5.80E-05	5.16E-05	1.33E-04
Phenanthrene	85018	3.13E-04	2.78E-04	7.19E-04
Pyrene	129000	2.77E-05	2.46E-05	6.36E-05
			Total HAP emissions per year	1.55E+00

3. STANDBY GENERATOR

The TAC and HAP emissions are calculated based on the following parameters:

Annual hours of operation:	50 each engine
Fuel usage:	173.3 gallons/hour

Annual fuel usage: 8.665 Mgal

The combined TAC and HAP emissions are calculated in the next table.

Table D-5 TAC and HAP Emissions – Standby Generator

TAC/HAP Pollutants	Aix Toxic Case Number	Emission Factor (lb/MMscf)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
Benzene	71432	0.1862	3.22E-02	8.07E-04
Formaldehyde	50000	1.7261	2.99E-01	7.48E-03
PAHs (including naphthalene)	107028	0.0559	9.67E-03	2.42E-04
Naphthalene	91203	0.0197	3.41E-03	8.54E-05
Acetaldehyde	75070	0.7833	1.36E-01	3.39E-03
Acrolein	1070208	0.0339	5.87E-03	1.47E-04
1,3-Butadiene	106990	0.2174	3.76E-02	9.42E-04
Chlorobenzene	108907	0.0002	3.50E-05	8.67E-07
Propylene	115071	0.4670	8.08E-02	2.02E-03
Hexane	110543	0.0269	4.65E-03	1.17E-04
Toluene	108883	0.1054	1.82E-02	4.57E-04
Xylenes	1330207	0.0424	7.34E-03	1.84E-04
Ethyl Benzene	100414	0.0109	1.89E-03	4.72E-05
Hydrogen Chloride	7647010	0.1863	3.22E-02	8.07E-04
Arsenic	7440382	0.0016	2.77E-04	6.93E-06
Cadmium	7440439	0.0015	2.60E-04	6.50E-06
Total Chromium	7440473	0.0006	1.04E-04	2.60E-06
Hexavalent Chromium	18540299	0.0001	1.70E-05	4.33E-07
Copper	7440508	0.0041	7.09E-04	1.78E-05
Lead	7439921	0.0083	1.44E-03	3.60E-05
Manganese	7439965	0.0031	5.36E-04	1.34E-05
Mercury	7439976	0.0020	3.46E-04	8.67E-06
Nickel	7440020	0.0039	6.75E-04	1.69E-05
Selenium	7782492	0.0022	3.81E-04	9.53E-06
Zinc	7440666	0.0224	3.88E-03	9.70E-05
Diesel Particulates	N/A	0.08	8.0E-02	2.0E-03
			Total HAP emissions per year	1.89E-02

Note diesel particulates has been classified as a hazardous air pollutant. The emission rate is assumed to the same as the PM, which is 0.08 lbs/hr.

4. <u>FACILITY TOTAL</u>

Once the repower project is completed the Scattergood Generating Station will have the following equipment:

One combined cycle gas turbine (GE 7FA), new CCGS
Two simple cycle gas turbines (GE LMS100), new SCGS
Two utility boilers, Unit 1 (de-rated) and Unit 2, existing equipment
Two standby generators, one new and one existing
Two oil water separators

The facility total HAP emissions are:

CCGS,	6.05 tons/year
SCGS,	3.1 tons/year, two units combined
Boiler 1,	0.136 tons/year
Boiler 2,	0.184 tons/year
Existing standby generator:	0.00 tons/year
New standby generator:	0.02 tons/year

The facility total HAP emissions are 9.5 tons/year.

APPENDIX E **GREENHOUSE GAS (GHG) EMISSIONS**

GHG POTENTIAL TO EMIT

The following six greenhouse gases (GHG) are considered:

carbon dioxide, CO_2,
methane, CH_4,
nitrous oxide, N_2O
hydrofluorocarbons, HFCs
perfluorocarbons, PFCs
sulfur hexafluoride, SF_6

The first three gases, CO_2, CH_4 and N_2O, are emitted from the operation of combustion sources.

EPA has published the emission factors for natural gas combustion based on the high heating value (HHV):

CO_2, 53.02 kg/mmBtu
CH_4, 1.0×10^{-3} kg/mmBtu
N_2O, 1.0×10^{-4} kg/mmBtu

The emissions factors are associated with the assumption of natural gas HHV of 1.028×10^{-3} mmBtu/scf. The emissions factors are converted to lb/mmscf:

CO_2, 120,160 lb/mmscf
CH_4, 2.27 lb/scf
N_2O, 0.227 lb/mmscf

In Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials CH4 is equivalent to 21 times of CO_2, and N_2O is equivalent to 310 times of CO_2 in terms of global warming potentials. The total GHG emissions in CO2e can be calculated as:

$$CO2e = CO_2 + 21*CH_4 + 310*N_2O$$

CO2e emissions can also be expressed as a function of fuel usage. Assuming fuel usage is F in mmscf,

$$CO2e = 120{,}160* F + 2.27*21* F + 0.227*310* F = 120{,}278 * F, \text{ in pounds}$$

CO2e = 60.139 tons/mmscf

GHG emissions from the CCGS and the SCGS are calculated accordingly.

1. CCGS

The daily maximum GHG emissions is calculated based on the fuel usage of 24 *2.046 mmscf = 49.104.

Daily maximum = 60.139 * 49.104 = 2,953 tons/day

The monthly GHG emissions is calculated based on the monthly fuel usage of 1,449.1 mmscf, which is calculated in Appendix A.6.

Monthly total = 60.139 * 1,449.1 = 87,147 tons/month

The annual fuel usage has been calculated in Appendix A.7 to be 17,062.6 mmscf. The corresponding GHG emissions are:

Annual total = 60.139 * 17,062.6 = 1,026,128 tons/year.

2. SCGS

For each GE LMS100 gas turbine the daily maximum GHG emissions is calculated based on the daily fuel usage of 24 *0.889 mmscf = 21.336.

Daily maximum = 60.139 * 21.336 = 1,283 tons/day

For each GE LMS100 gas turbine the monthly GHG emissions is calculated based on the monthly fuel usage of 641.2 mmscf, which is calculated in Appendix B.6.

Monthly total = 60.139 * 641.2 = 38,561 tons/month

GE LMS100 gas turbine the annual fuel usage has been calculated in Appendix B.7 to be 4,356.33 mmscf. The corresponding GHG emissions:

Annual total = 60.139 * 4,356.33 = 261,985 tons/year

The total GHG emissions from the two GE LMS100 gas turbines are:

261,985*2 =523,970 tons/year

3. Standby Generator

The EPA has established the following emission factors for diesel combustion:

CO_2, 73.96 kg/mmBtu
CH_4, 3.0 x 10^{-3} kg/mmBtu
N_2O, 6.0 x 10^{-4} kg/mmBtu

The default heating value used by EPA is 0.138 mmBtu/gallon. Thus, the equivalent emission factors in lb/Mgal are:

CO_2, 22,501 lb/Mgal
CH_4, 0.913 lb/Mgal
N_2O, 0.183 lb/Mgal

The annual fuel usage has been calculated in Appendix C to be 8.665 Mgal for the standby generator. The GHG emissions are calculated in the next table.

	Emissions (tons/year)	CO2e (tons/year)
CO_2	97.50	97.50
CH_4	0.004	0.08
N_2O	0.0008	0.25
Total GHG emissions		98

4. Circuit Breakers

The GHG emissions from the circuit breakers are estimated to be 55.4 tons CO2e emissions per year.

The combined total GHG emissions from the CCGS, SCGS, and the standby generator are:

CO2e: 1,026,128 +523,970 +98 +55.4 =1,550,251 tons/year

GHG BACT Analysis

In order to determine the CO2e in lbs/MWh the total power generation in megawatt hours has to be calculated.

1. Combined Cycle Generation System (CCGS)

The following annual operating schedule is proposed by LADWP:

Total hours of operation:	8,760 hours
Total cold startups:	53
Total non-cold startups:	677
Total shutdowns:	730
Lowest operating load:	50%
New equipment degradation factor:	3%

The net baseload operation, excluding startups and shutdowns, is 7133.77 hours per year.

Power generated by the CCGS is calculated at 50%, 75%, and 100% annual average load. The annual operation schedule and the CCGS basic parameters are shown in the next table.

	50% Average Load	75% Average Load	100% Average Load
Cold Startups, times per year	53	53	53
Non-cold Startups, times per year	677	677	677
Shutdowns, times per year	730	730	730
Non-operational hours between daily startups, hours per year	182.5	182.5	182.5
Base load operation, hours per year	7133.77	7133.77	7133.77
CTG power output, net kW(1)	100,444	151,754	203,241
ST power output, net kW(1)	79,192	90,015	105,534
CCGS power output, net kW	179,636	241,769	308,775
CTG heat rate, net (Btu/kw-h, LHV)	12,396	10,062	9,226
CCGS heat rate, net (Btu/kw-h, LHV)	6,931	6,316	6,073
Fuel input (mmBtu/hr, LHV)(1)	1,245.1	1,527.0	1,875.1
Total fuel usage, per year (mmscf)	12,161.70	14,351.76	17,062.60

(1) GE provided information

Power generated during the cold startup, non-cold startup, shutdown, and base load operation are calculated.

Cold Startup

A cold startup takes 166 minutes. According to GE electricity is not generated to the grid during the first 7 minutes. Although the combustion turbine load is brought up quickly the steam turbine requires a much longer time to come online. For the majority of the process the steam turbine is not available. Therefore, the power generated by the steam turbine during a cold startup is not included in the calculations.

Fuel usage per startup 4,939 mmBtu, LHV
Fuel usage of the first 7 minutes: 30.8 mmBtu, LHV
Fuel usage for power generation: 4,908 mmBtu, LHV

	50% Average Load	75% Average Load	100% Average Load
Cold startup fuel usage, mmBtu	4,908	4,908	4,908
CTG heat rate, Btu/kw-hour	12,396	10,062	9,226
Net power output, kw-hour	395,934	487,776	531,975

Non-cold Startup

A non-cold startup takes 88 minutes. According to GE electricity is not generated to the grid during the first 7 minutes. During this process the steam turbine is mostly available. Therefore, the power generated by the steam turbine during a non-cold startup is not included in the calculations.

Fuel usage per startup 2,615 mmBtu, LHV
Fuel usage of the first 7 minutes: 30.8 mmBtu, LHV
Fuel usage for power generation: 2,584 mmBtu, LHV

	50% Average Load	75% Average Load	100% Average Load
Non-cold startup fuel usage, mmBtu	2,584	2,584	2,584
CTG heat rate, Btu/kw-hour	6,931	6,316	6,073
Net power output, kw-hour	372,818	409,120	425,490

Shutdown

A shutdown stakes 25 minutes. According to GE electricity is not loaded to the grid in the last 8 minutes. It is assumed that both the combustion turbine and the steam turbine are available during the remaining 17 minutes of the process.

Fuel usage per shutdown 313 mmBtu, LHV
Fuel usage of the first 7 minutes: 9.8 mmBtu, LHV
Fuel usage for power generation: 303 mmBtu, LHV

	50% Average Load	75% Average Load	100% Average Load
Shutdown fuel usage, mmBtu	303	303	303
CCGS heat rate, Btu/kw-hour	6,931	6,316	6,073
Net power output, kw-hour	43,717	47,973	49,893

Power Generation per Year

Total power generated by the CCGS in megawatts-hour is calculated in the next table.

	50% Average Load	75% Average Load	100% Average Load
Cold startups per year	53	53	53
Non-cold startups per year	677	677	677
Shutdowns per year	730	730	730
Non-operational hours between daily startups in a year	182.5	182.5	182.5
Base load operation (hours per year)	7133.77	7133.77	7133.8
Power output per cold startup, MWh	395.9	487.8	532.0
Power output per non-cold startup, MWh	372.8	409.1	425.5
Power output per shutdown, MWh	43.7	48.0	49.9
Power output per base load hour, MWh	179.6	241.8	308.8
Power output, cold startup total, MWh	20,985	25,852	28,195
Power output, non-cold startup total, MWh	252,398	276,974	288,057
Power output, shutdown total, MWh	31,913	35,020	36,422
Power output, base load total, MWh	1,314,265	1,724,724	2,202,730
CCGS power generation in a year, MWh	1,619,561	2,062,570	2,555,404
CCGS power generation in a year, MWh, with a 3% degradation factor	1,570,974	2,000,693	2,478,742

Based on annual fuel consumption of the three operating scenarios the CO2e emissions are calculated. As shown in the early section CO2e emissions can be calculated using:

CO2e = 60.139 * Fuel Usage

	50% Average Load	75% Average Load	100% Average Load
Total fuel usage, per year (mmscf)	12,161.70	14,351.76	17,062.60
CO2e emissions (tons/year)	731,392	863,100	1,026,128

The effective CO2e emission factors are:

	50% Average Load	75% Average Load	100% Average Load
CO2e emissions (tons/year)	731,392	863,100	1,026,128
CCGS power generation, mw-hr per year	1,570,974	2,000,693	2,478,742
CO2e,tons/mw-hr	0.466	0.431	0.414
CO2e, lbs/mw-hr	931	863	828

The maximum GHG emissions from the CCGS is 1,026,128 tons CO2e per year.

2. Simple Cycle Generating System (SCGS)

Because the SCGS consists of two identical GE LMS100 gas turbine generators the GHG BACT analysis is conducted on one GE LMS100 unit.

The following annual operating schedule is proposed by LADWP:

Total hours of operation:	5,168 hours
Total startups:	1,460
Total shutdowns:	1,460
Lowest operating load:	60%
New equipment degradation factor:	2%

The net baseload operation, excluding startups and shutdowns, is 4,309 hours.

	60% Average Load	75% Average Load	100% Average Load
Startups, times per year	1,460	1,460	1,460
Shutdowns, times per year	1,460	1,460	1,460
Base load operation, hours per year	4,309	4,309	4,309
CTG power output, net kW	59,320	75,000	100,000
CTG power output, gross kW	61,934	77,168	102,968
CTG heat rate, net (Btu/kw-h, LHV)	9,427	8,654	8.147
CTG heat rate, gross (Btu/kw-h, LHV)	9,029	8,411	7,912
Fuel input (mmBtu/hr, LHV)	559.2	649.06	814.7
Total fuel usage, startup + shutdown + baseload per year (mmscf)	3,155.03	3,577.57	4,356.43

Startup

A startup takes 25 minutes. According to GE electricity is not generated to the grid during the first 1.8 minutes. Power produced in the remaining 23.2 minutes are calculated.

Fuel usage per startup 279.4 mmBtu, LHV
Fuel usage of the first 1.8 minutes: 3.9 mmBtu, LHV
Fuel usage for power generation: 275.5 mmBtu, LHV

	60% Average Load	75% Average Load	100% Average Load
Cold startup fuel usage, mmBtu	275.5	275.5	275.5
CTG heat rate, Btu/kw-hour	9,427	8,654	8,147
Net power output, kw-hour	29,225	31,835	33,816

Shutdown

A shutdown stakes 10.3 minutes. According to GE electricity is not loaded to the grid in the last 5 minutes. Power produced in the remaining 5.3 minutes are calculated.

Fuel usage per shutdown 50.4 mmBtu, LHV
Fuel usage of the last 5 minutes: 9.4 mmBtu, LHV
Fuel usage for power generation: 41 mmBtu, LHV

	60% Average Load	75% Average Load	100% Average Load
Shutdown fuel usage, mmBtu	41	41	41
CTG heat rate, Btu/kw-hour	9,427	8,654	8,147
Net power output, kw-hour	4,349	4,738	5,033

Power Generation per Year

Total power generated by the one GE LMS100 generator in net megawatts-hour is calculated in the next table. The total operating hours are assumed to be 5,168 hours year.

	60% Average Load	75% Average Load	100% Average Load
Startups per year	1,460	1,460	1,460
Shutdowns per year	1,460	1,460	1,460
Base load operation (hours per year)	4,309	4,309	4,309
Power output per startup, MWh	29.22	31.83	33.82
Power output per shutdown, MWh	4.35	4.74	5.03
Power output per base load hour, MWh	59.32	75	100
Power output, startup total, MWh	42,668	46,479	49,372
Power output, shutdown total, MWh	6,350	6,917	7,347
Power output, base load total, MWh	255,612	323,178	430,903
Power generation in a year, net MWh	304,630	376,574	487,622
Power generation in a year, net MWh, with a 2% degradation factor	298,537	369,042	477,870

Based on annual fuel consumption of the three operating scenarios the CO2e emissions are calculated.

CO2e = 60.139 * Fuel Usage

	60% Average Load	75% Average Load	100% Average Load
Total fuel usage, per year (mmscf)	3,155.03	3,577.57	4,356.33
CO2e emissions (tons/year)	189,740	215,151	261,985

The net effective CO2e emission factors are:

	60% Average Load	75% Average Load	100% Average Load
CO2e emissions (tons/year)	189,740	215,151	261,985
Net power generation, mw-hr per year	298,537	369,042	477,870
CO2e,tons/MWh, net	0.636	0.583	0.548
CO2e, lbs/MWh, net	1,271	1,166	1,096

The maximum GHG emissions from one GE LMS100 generator is 261,985 CO2e tons per year. Since the SCGS has two GE LMS100 generators the maximum CO2e emissions are 523,970 lbs.

APPENDIX F RULE 1325 PM2.5 EMISSIONS

1. OFFSET CALCULATIONS

The repower project has emission increases from the new gas turbine units and emission decreases from shut down of the Boiler 3 and de-rate of Boiler 1 generators. The contemporaneous emission reduction is calculated based on the 5-year look back period, and the baseline emissions are the 24-month rolling average in the 5-year period. Therefore, LADWP has compiled the emissions data of the two boilers, Units 1 and 3, of the last five years. The fuel usage data were provided to AQMD on August 3, 2012.

For Boiler #1, the highest 24-month total is from 02/2008-01/2010.

Natural gas usage: 7,724.8 mmscf in two years, 3,862.4 mmscf/year
Digester gas usage: 3,774.6 mmscf in two years, 1,887.3 mmscf/year

The Boiler #1 baseline PM2.5 emissions are:

3,862.4 mmscf/year*7.6 lb/mmscf + 1,887.3 mmscf/year* 13 lb/mmscf = 26.945 ton/year

For Boiler #3, the highest 24-month total is from 06/2007-05/2009.

Natural gas usage: 13,610.0 mmscf in two years, 6,805.0 mmscf/year

The Boiler #3 baseline PM2.5 emissions are:

6,805.0 mmscf/year* 7.6 lb/mmscf = 25.859 ton/year

Because Boiler #1 will be de-rated by 64.3 MW from 185 MW to 120.7 MW the emission reduction from Boiler #1 de-rate is:

64.3/185 * 26.945 = 9.365 tons/year

The emission reduction from Boiler #3 shutdown is:

25.859 ton/year

The total PM2.5 emission reduction from Boiler #1 de-rate and Boiler #3 shutdown is:

9.365 + 25.859 = 35.224 tons/year

The new units PM2.5 emissions are calculated in the next table.

CCGS:	87,045 lbs/year, as calculated in Table A-12
SCGS #1:	30,109 lbs/year, as calculated in Table B-10
SCGS #2:	30,109 lbs/year, as calculated in Table B-10
The standby generator:	4 lbs/year, as calculated in Table C-1

Total PM2.5 emissions from the new equipment:

87,045 +30,109*2 +4 = 147,267 lbs/year = 73.633 tons/year

The net emissions increase is:

73.633 – 35.224 = 38.409 ton/year, 210.5 lbs/day (based on 365 days/year)

Offset liability is calculated at the ratio of 1.1 to 1.

210.5 * 1.1 = 231.6 lbs/day, or 232 lbs/day

LADWP would be required to provide 232 pounds per day of federally enforceable PM2.5 emission reduction credits, if the offset requirement is triggered.

2. PM2.5 EMISSION FACTORS

The following emission factors are used in calculation of the PM2.5 PAL limit.

D1 This is the existing utility boiler B1. The PM2.5 emission factor is the AP-42 factor for PM10 for natural gas combustion. Boiler #1 will no longer use digester gas after the completion of the repower project.

EF1 = 7.6 lb/mmscf

D2 This is the existing utility boiler B2. The PM2.5 emission factor is the AP-42 factor for PM10 for natural gas combustion.

EF1 = 7.6 lb/mmscf

D19 This is a standby diesel engine generator. The fuel consumption rate is 32 gallons/hr, and the PM10 emissions are 1.1 lbs/hr (from A/N134734). The effective emission factor is:

EF_{D1} =1.1/32*1,000 = 34.4 lb/Mgal

D96 This is the GE 7FA.05 generator. It is Unit #4. The PM2.5 emission factor is the same as the PM10 factor, calculated in Table A-9

EF4 = 5.10 lb/mmscf

D104 This is the first of two GE LMS100 generators. It is Unit #6. The PM2.5 emission factor is the same as the PM10 factor, calculated in Table B-8.

EF4 = 6.70 lb/mmscf

D110 This is the second of two GE LMS100 generators. It is Unit #7. The PM2.5 emission factor is the same as the PM10 factor, calculated in Table B-8.

EF4 = 6.70 lb/mmscf

D116 This is the standby generator. Each engine has the fuel consumption of 173.3 gallons per hour. The PM2.5 emission rate is, the same as PM10 and as calculated in Table C-1, 0.08 lb/hr.

EF_{D116} = 0.08/173.3*1000 =0.5 lbs/Mgal

3. <u>FACILITY TOTAL PM2.5 EMISSIONS</u>

The facility total PM2.5 potential to emit, prior to the repower project, are calculated for the determination whether it is a major source. The calculated is based on the maximum fuel usage.

Boilers 1 & 2:

PM2.5 from natural gas combustion: 13,210 mmscf/year * 7.6 lb/mmscf = 50.2 tons/year
PM2.5 from digester gas combustion: 3,013 mmscf/year * 13 lb/mmscf = 19.6 tons/year
Total PM2.5 for each boiler: 69.8 tons/year

Boiler 3:

PM2.5 from natural gas combustion: 39,622 mmscf/year *7.6 lb/mmscf = 150.6 tons/year

Facility total PM2.5:

69.8 + 69.8 + 150.6 = 290.2 tons/year

Since the facility total PM2.5 potential to emit exceeds 100 tons per year the facility is a PM2.5 major source.

APPENDIX G RECLAIM TRADING CREDIT REQUIREMENT

In accordance with Rule 2005 the facility is required to set aside sufficient RECLAIM Trading Credits (RTC) to cover the NOx emissions from the first year operation. The anticipated annual NOx emissions from the repower project is tabulated in the next table.

	GE 7FA.05	GE LMS100	GE LMS100	Standby Generator
NOx	177,809	74,745	74,745	1,477

The total RTC requirements are:

RTC, 1st year = 328,776 lb/year

After the first year the anticipated annual NOx emissions are:

	GE 7FA.05	GE LMS100	GE LMS100	Standby Generator
NOx	167,272	69,259	69,259	1,477

The total RTC requirements are:

RTC = 307,267 lb/year