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PRELIMINARY DETERMINATION OF COMPLIANCE

COMPANY NAME AND ADDRESS

El Segundo Power, LLC
301 Vista Del Mar
El Segundo, CA 90245

Contact: George L. Piantka, P.E. (760) 710-2156

EQUIPMENT LOCATION

301 Vista Del Mar
El Segundo, CA 90245
SCAQMD ID #115663

EQUIPMENT DESCRIPTION

Section H of the Facility Permit, ID# 115663, Permit to Construct and Temporary Permit to Operate:

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
PROCESS 1 – INTERNAL COMBUSTION					
GAS TURBINE, UNIT NO. 9, NATURAL GAS, GENERAL ELECTRIC, MODEL 7FA.05, FAST-START, COMBINED CYCLE, WITH DRY LOW-NOX BURNERS, 2,168 MMBTU/HR HHV @ 41°F, WITH: A/N: 548594 HEAT RECOVERY STEAM GENERATOR (HRSG)	D90	D95, C96	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005, RULE 1703-PSD-BACT]; **NOx:** 30.88 LB/MMSCF COMMISSIONING (1) [RULE 2012]; **NOx:** 9.42 LB/MMSCF INTERIM (1) [RULE 2012]; **NOx:** 15 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK];**CO**: 2.0 PPMV (4) [RULE 1703 PSD-BACT]; **CO:** 2,000 PPMV (5) [RULE 407];	A63.3, A99.12, A99.13, A195.12, A195.13, A195.14, A327.1, B61.2, C1.7, D29.10, D29.11, D29.12, D82.6, D82.7, E193.2,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
GENERATOR, SERVING UNIT NO. 9, 222 GROSS MW @ 41°F STEAM TURBINE, GENERAL ELECTRIC, MODEL SC GENERATOR, SERVING STEAM TURBINE, 112 GROSS MW @ 41°F.				**VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM10**: 9.5 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**: 0.06 lb/MMBTU (8)[40CFR 60 SUBPART KKKK]; **SO_2:** (9)[40CFR 72 – ACID RAIN]; **CH2O:** 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	E193.5, E193.6, I297.3, K40.5, K67.6
BURNER, DUCT, NATURAL GAS, 268 MMBTU/HR HHV @ 41°F, LOCATED IN THE HRSG OF GAS TURBINE NO. 9 WITH A/N 548594	D95	D90	NOX: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005, RULE 1703-PSD-BACT]; **NOx:** 30.88 LB/MMSCF COMMISSIONING (1) [RULE 2012]; **NOx:** 9.42 LB/MMSCF INTERIM (1) [RULE 2012]; **NOx:** 15 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 2.0 PPMV (4) [RULE 1703 PSD-BACT]; **CO:** 2,000 PPMV (5) [RULE 407]; **VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM10**: 9.5 LB/HR (5) [RULE 1303]; **PM:** 0.1 GR/SCF (5A) [RULE 409]; **PM:** 11 LBS/HR (5B) [RULE 475]; **PM:** 0.01 GR/SCF (5C) [RULE 475]; **SO_2**: 0.06 lb/MMBTU (8)[40CFR 60 SUBPART KKKK];	A99.12, A99.13, A195.12, A195.13, A195.14, A327.1, B61.2, C1.7, D29.10, D29.11, D29.12, D82.6, D82.7, E193.2, E193.5, I297.3, K40.5, K67.6

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
				SO_2: (9)[40CFR 72 – ACID RAIN]; **CH2O:** 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	
CO OXIDATION CATALYST, UNIT NO. 9, BASF, CATALYST VOLUME: 290 FT^3; WITH: A/N: 548591	C96	C97, D90,			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 9, CORMETECH, CATALYST VOLUME: 2,050 FT^3; WIDTH: 9 FT 10 IN; HEIGHT: 6 FT 4 IN; LENGTH: 1 FT 9 IN; WITH: AMMONIA INJECTION, AQUEOUS AMMONIA A/N: 548591	C97	C96, S99		**NH_3:** 5 PPMV (4) [RULE 1303-BACT]	D12.14, 12.15, D12.16, 29.3, E179.7, E179.8, E193.2, E193.7
STACK, SERVING UNIT NO. 9, DIAMETER: 20 FT, HEIGHT: 210 FT, WITH: A/N: 548594	S99	C97			
GAS TURBINE, UNIT NO. 11, NATURAL GAS, ROLLS ROYCE , MODEL: TRENT 60, SIMPLE CYCLE, WITH WATER INJECTION, 516 MMBTU/HR @ 78°F, WITH: A/N: 548589 GENERATOR, 57.4 GROSS MW @ 78°F	D100	C106	NOX: MAJOR SOURCE	**NOx**: 2.5 PPMV (4) [RULE 2005, RULE 1703-PSD-BACT]; **NOx:** 96.58 LB/MMSCF COMMISSIONING (1) [RULE 2012]; **NOx:** 16.16 LB/MMSCF INTERIM (1) [RULE 2012];**NOx:** 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 PSD-BACT]; **CO:**	A63.4, A99.14, A99.15, A195.15, A195.16, A195.17, A327.1, B61.2, C1.8, D29.10, D29.11, D29.12, D82.6, D82.7,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
				2,000 PPMV (5) [RULE 407]; **VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM10**: 9.5 LB/HR (5) [RULE 1303]; **PM:** 0.1 GR/SCF (5A [RULE 409]; **PM:** 11 LBS/HR (5B) [RULE 475]; **PM:** 0.01 GR/SCF (5C) [RULE 475]; **SO_2**: 0.06 lb/MMBTU (8)[40CFR 60 SUBPART KKKK]; **SO_2:** (9)[40CFR 72 – ACID RAIN]; **CH2O:** 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	E193.2, E193.5, E193.8, I297.4, K40.5, K67.6
CO OXIDATION CATALYST, UNIT NO. 11, PEERLESS, CATALYST VOLUME: 420 FT^3; WITH: A/N: 548588	C102	C100, D103			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 11, PEERLESS, CATALYST VOLUME: 1,272 FT^3; WIDTH: 19 FT 6 IN; HEIGHT: 33 FT 0 IN; LENGTH: 2 FT 6 IN; WITH: AMMONIA INJECTION AQUEOUS AMMONIA A/N: 548588	C103	C102, S105		**NH3:** 5 PPMV (4) [RULE 1303-BACT]	D12.17, D12.18, D12.19, E179.9, E179.10, E193.2, E193.7
STACK, SERVING UNIT NO. 11, DIAMETER: 11 FT, HEIGHT: 150 FT, WITH: A/N: 548589	S105	C103			

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
GAS TURBINE, UNIT NO. 12, NATURAL GAS, ROLLS ROYCE, MODEL TRENT 60, SIMPLE CYCLE, WITH WATER INJECTION, 516 MMBTU/HR @ 78°F, WITH: A/N: 548589 GENERATOR, 57.4 GROSS MW @ 78°F	D106	C108	NOX: MAJOR SOURCE	**NOx**: 2.5 PPMV (4) [RULE 2005, RULE 1703-PSD-BACT]; **NOx:** 96.58 LB/MMSCF COMMISSIONING (1) [RULE 2012]; **NOx:** 16.16 LB/MMSCF INTERIM (1) [RULE 2012];**NOx:** 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 PSD-BACT]; **CO:** 2,000 PPMV (5) [RULE 407]; **VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM10**: 5 LB/HR (5) [RULE 1303]; **PM:** 0.1 GR/SCF (5A) [RULE 409]; **PM:** 11 LBS/HR (5B) [RULE 475]; **PM:** 0.01 GR/SCF (5C) [RULE 475]; **SO_2**: 0.06 lb/MMBTU (8)[40CFR 60 SUBPART KKKK]; **SO_2:** (9)[40CFR 72 – ACID RAIN]; **CH2O:** 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	A63.4, A99.14, A99.15, A195.15, A195.16, A195.17, A327.1, B61.2, C1.8, D29.10, D29.11, D29.12, D82.6, D82.7, E193.2, E193.5, E193.8, I297.4, K40.5, K67.6
CO OXIDATION CATALYST, UNIT NO. 12, PEERLESS, CATALYST VOLUME: 420 FT^3; WITH: A/N: 548588	C108	C106, D109			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 12, PEERLESS, CATALYST	C109	C108, S111		**NH3:** 5 PPMV (4) [RULE 1303-BACT]	D12.17, D12.18, D12.19,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
VOLUME: 1,272 FT^3; WIDTH: 19 FT 6 IN; HEIGHT: 33 FT 0 IN; LENGTH: 2 FT 6 IN; WITH: A/N: 548588 AMMONIA INJECTION AQUEOUS AMMONIA					E179.9, E179.10, E193.2, E193.7
STACK, SERVING UNIT 12, DIAMETER: 11 FT, HEIGHT: 150 FT, WITH: A/N: 548589	S111	C109			
BOILER, AUXILIARY, CLEAVER BROOKS, MODEL NB-100D-40, WATERTUBE, NATURAL GAS, 36 MMBTU/HR WITH LOW NOX BURNER WITH A/N: 548593 BURNER, 36 MMBTU/HR, NATURAL GAS, WITH LOW NOX BURNER	D112		NOX: LARGE SOURCE	**NOx**: 5.0 PPMV (4) [RULE 2005, RULE 1703-PSD-BACT]; **CO**: 50 PPMV(5) [RULE 1703-PSD BACT]; **CO**: 2000 PPMV (5A) [RULE 407]; **PM**: 0.1 GRAINS/SCF (5) [RULE 409]	A63.4 B61.2, C1.9, D29.4, E193.2, E193.5 I297.6 K40.1

BACKGROUND

El Segundo Power, LLC operates the existing power generating facility located on a 32.8 acre site at 301 Vista Del Mar Boulevard in the City of El Segundo. The site is located at Township 3 South, Range 15 West, on the Venice U.S. Geological Survey (USGS) quadrangle map.
The facility is bordered on the west by Santa Monica Bay, on the east by Vista Del Mar Boulevard, on the north by the Chevron Marine Terminal, and on the south by 45th Street in the city of

Manhattan Beach. The facility is designed to provide electricity to the Southern California Edison (SCE) power distribution grid and has been in continuous operation since 1955. The original facility consisted of Boilers #1 and #2, each rated at 175 MW, and Boilers #3 and #4 each rated at 335 MW. In 2000, El Segundo Power, LLC submitted applications for Permit to Construct for a proposed 647 MW ocean-water cooled (once-through cooling) power generating facility which consisted of 2 combined cycle gas turbines to replace Boilers #1 and 2. Boilers #1 and #2 were removed from service in December 2002. The proposed new construction resulted in an increase in generating capacity of greater than 50 megawatts. As such, the proposed El Segundo Power Redevelopment (ESPR) project was subject to review and approval from the California Energy Commission (CEC). The ESPR Project was approved by the CEC and El Segundo Power, LLC was issued a CEC License for the proposed ESPR Project in February 2005. The ESPR Project was amended in 2010 to replace the originally selected combined cycle gas turbines with rapid-start combined cycle units by a different manufacturer and to eliminate the once-through cooling. El Segundo Power, LLC decided in addition to the previously removed Boilers #1 and #2, it will also remove Boiler #3 from service prior to the start-up of Gas Turbine Units #5 and #7 as part of the offset strategy to qualify for the Rule 1304(a)(2) modeling and offset exemption on a MW-to-MW basis. The resulting shutdown of Boilers #1, #2, and #3 exceeded the required offsets for the proposed project by 112 MW. As such, the proposed ESPR Project had a zero MW increase. Permits to Construct were issued for the ESPR Project on July 13, 2010. The total present electrical generating capacity for the ESPR Project is 573 MW.

PROPOSED MODIFICATION

In addition to the 573 MW proposed and completed under the ESPR Project, El Segundo Power, LLC is proposing new, further modifications to the facility under the El Segundo Power Facility Modification (ESPFM) Project. The ESPFM Project will consist of the installation and operation of an efficient, state-of-the-art electrical power generation system. The new power generating system will include one combined cycle gas turbine, two simple cycle gas turbines, and an auxiliary boiler and associated air pollution control (APC) equipment. The combined cycle gas turbine will consist of a General Electric (GE) Model 7FA gas turbine and a General Electric Model SC steam turbine. The gas turbine is rated at 222 MW and the steam turbine is rated at 112 MW. The total combined cycle capacity will be 334 MW gross. The simple cycle gas turbines will consist of two Rolls Royce (RR) Trent 60 gas turbines, each rated at 57.4 MW for a total simple cycle capacity of 114.8 MW gross. The total plant capacity of the proposed new power system will be 448.8 MW gross. As with the ESPR Project , the CEC will continue its jurisdiction over the proposed ESPFM Project. El Segundo Power, LLC has also submitted an amended petition to the CEC to incorporate the proposed facility modifications under the ESPFM Project. The GE 7FA combined cycle gas turbine and the two RR Trent 60 simple cycle gas turbines will operate exclusively with natural gas. The new power system will include air pollution control equipment for each of the gas turbines. Each gas turbine will be connected to a CO oxidation catalyst followed by a selective catalytic reduction (SCR) unit. The CO oxidation catalyst converts CO to CO_2, in addition to removing some VOC emissions. The SCR injects aqueous ammonia at a given temperature window to react with the combustion exhaust, thus reducing NOx to nitrogen.

The El Segundo facility currently operates a 20,000 gallon permitted (A/N 379904, P/N G20414) 29% aqueous ammonia storage tank and does not plan to build any new ammonia storage tanks. As part of the new power generation system, the ESPFM Project will require a source of steam to utilize the rapid-start capability of the GE 7FA combined cycle gas turbine. The steam will be provided by the proposed auxiliary boiler. The new GE 7FA combined cycle gas turbine will be labeled as Unit #9. The two RR Trent 60 simple cycle gas turbines will be labeled as Units #11 and 12, respectively (The steam turbine portion of the combined cycle system will be designated as Unit 10). In accordance with AQMD Rules 1303 and 1313, El Segundo Power, LLC will remove Boiler #4 from service and surrender the permit within 90 calendar days after the initial startup of the new power generating system. The following table is a summary of the applications submitted by El Segundo Power, LLC. The total processing fees in Table 1 below include fees for regular plus expedited processing. A/Ns 548590 and 548588 receive reduced processing fees (50%) for identical equipment.

Table 1 – Applications Submitted to SCAQMD

Applications	Equipment Description	Processing Fees
548594	GE 7FA Combined Cycle Gas Turbine #9, > 50 MW	$24,286.86
548589	RR Trent 60 Simple Cycle Gas Turbine #11, > 50 MW	$24,286.86
548590	RR Trent 60 Simple Cycle Gas Turbine #12, > 50 MW	$12,143.43
548591	SCR/CO Catalyst for Gas Turbine #9	$5,160.09
548592	SCR/CO Catalyst for Gas Turbine #11	$5,160.09
548588	SCR/CO Catalyst for Gas Turbine #12	$2,580.05
548593	Auxiliary Boiler, 36 MMBTU/hr	$7,121.79
548587	Title V/RECLAIM Significant Permit Revision	$1,789.12
Total processing fee, including 50% fee for Expedited Permit Processing		$82,528.29

El Segundo Power, LLC 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 in Table 1 above were submitted on March 19, 2013. The applicant requested expedited permit processing of the applications, and paid the 50% additional fee per Rule 301(u). They were deemed incomplete on April 12, 2013. The SCAQMD requested additional information from the applicant in a letter dated April 12, 2013. The requested additional information has been received and the applications were deemed complete on November 20, 2013.

<u>PROCESS DESCRIPTION</u>

<u>Combined Cycle Generating System (CCGS)</u>

The CCGS will consist of one GE 7FA combined cycle gas turbine generator. The GE 7FA is comprised of a gas turbine and a steam turbine. Each part is connected to a separate electric generator. Combustion air is supplied to the gas turbine 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 inlet air is routed 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 both the turbine and the electric generator. The GE 7FA will generate a maximum of 222 MW of electricity at 41°F.

The exhaust of the CTG passes through a duct burner (DB) prior to entry 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 SC 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 GE SC steam turbine will generate a maximum of 112 MW of electricity at 41°F.

The specifications of the CCGS are provided in Table 2 below. The natural gas provided at El Segundo Power, LLC is California Public Utilities Commission (CPUC) quality natural gas with a higher heating value (HHV) of 1,030 BTU/scf and a lower heating value (LHV) of 929 BTU/scf. The total net heat rate of the CCGS (including duct burner firing) is 6,754 BTU/kWh based on the LHV at 41°F. The total gross power generated by the CCGS is 334 MW at 41°F.

<u>Fast Start</u>

GE's Fast-Start® technology will use steam supplied from the auxiliary boiler to keep the CCGS in a continuous state of readiness and to reach its base load quickly while simultaneously reducing both start-up time of the gas turbine and the associated emissions. The auxiliary boiler specifications are listed in Table 4 below.

Table 2 – CCGS Specifications

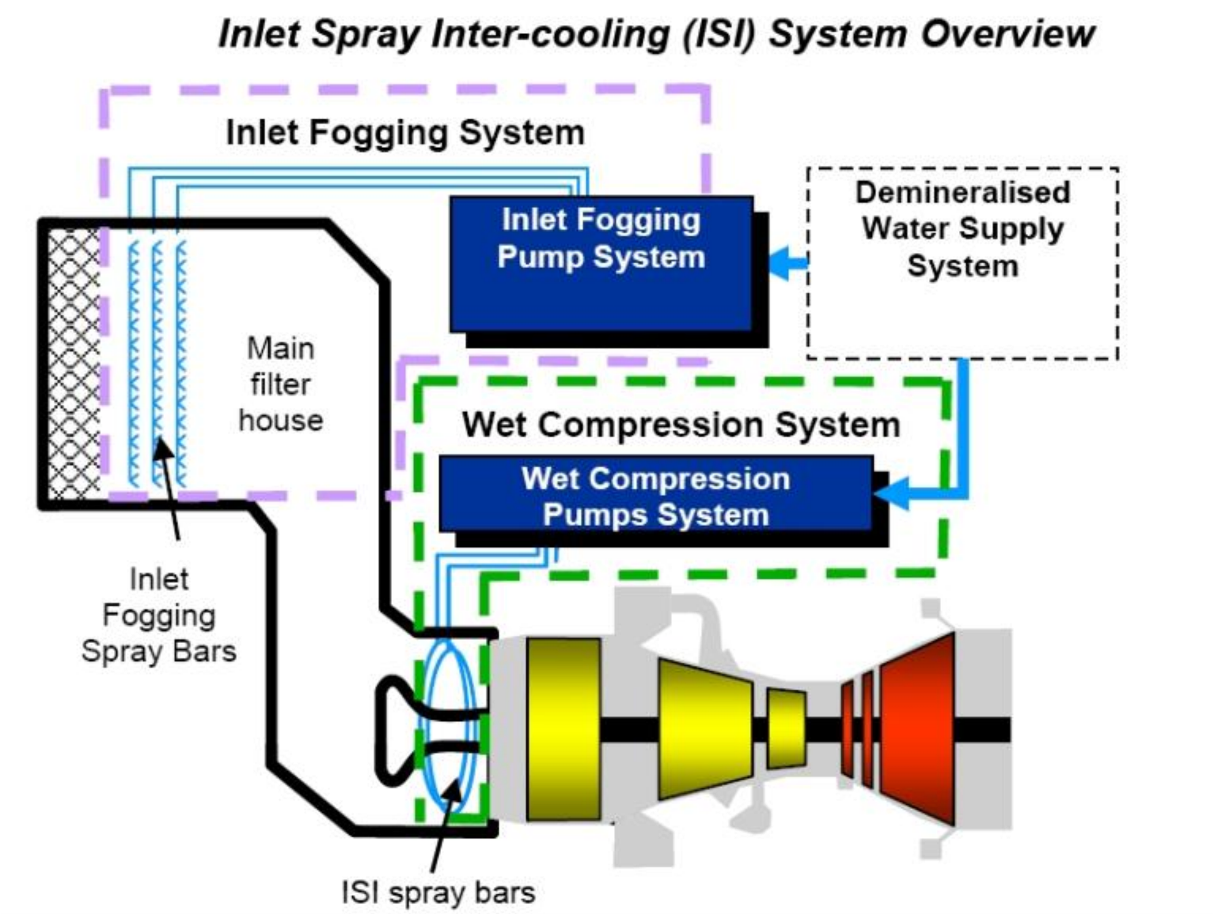
PARAMETERS	**SPECIFICATIONS**
Gas Turbine Manufacturer	General Electric
Model No.	7FA.05 Fast-Start®
Steam Turbine Make & Model	General Electric SC
Fuel Type	California Public Utilities Commission (CPUC) Quality Natural Gas
Gas Turbine Maximum Heat Input	2,168 MMBTU/hr @ 41°F (HHV) 1,955 MMBTU/hr @ 41°F (LHV)
Duct Burner Maximum Heat Input	268 MMBTU/hr @ 41°F (HHV)

	242 MMBTU/hr @ 41°F (LHV)
Total Maximum Heat Input	2,436 MMBTU/hr @ 41°F (HHV) 2,197 MMBTU/hr @ 41°F (LHV)
Gas Turbine Maximum Fuel Consumption	2.105 MMSCF/hr @ 41°F
Duct Burner Maximum Fuel Consumption	0.260 MMSCF/hr @ 41°F
Total Maximum Fuel Consumption	2.365 MMSCF/hr[a] @ 41°F
Gross Plant Heat Rate, HHV	7,301 BTU/kWh @ 41°F
Gross Plant Heat Rate, LHV	6,583 BTU/kWh @ 41°F
HRSG Maximum Exhaust Flow	859,000 DSCFM
HRSG Maximum Exhaust Temperature	219°F @ 41°F Ambient
NOx Combustion Control	Dry Low NOx Combustor
Ammonia Injection Rate	135 lb/hr 29% aqueous NH_3 at full load @ 41°F
Post Combustion Control	SCR and CO Catalyst
Net Plant Heat Rate, HHV	7,490 BTU/kWh @ 41°F
Net Plant Heat Rate, LHV	6,754 BTU/kWh @ 41°F
GE 7FA Gas Turbine Power Generation	222 MW @ 41°F
Steam Turbine Power Generation	112 MW @ 41°F
Total CCGS Gross Power Generation	334 MW @ 41°F[b]

[a] Represents the total maximum fuel consumption of the gas turbine plus the duct burner, based on the HHV and a total maximum heat input of 2,436 MMBTU/hr and 1,030 BTU/scf natural gas heat content.
[b] Represents the total power generated from the GE 7FA gas turbine plus the GE SC steam turbine.

Simple Cycle Generating System (SCGS)

The SCGS will consist of two RR Trent 60 simple cycle gas turbine generators. Each Trent 60 is connected to a separate electric generator. Below is a schematic of the Inlet Spray Inter-cooling (ISI) system as configured on each of the Trent 60 simple cycle gas turbines. The ISI system consists of an inlet fogging system and a wet compression system. A de-mineralized water supply system is used to supply de-mineralized water to both the inlet fogging system and the wet compression system. The ISI system provides performance improvements, while minimizing the additional plant water consumption and auxiliary load when compared to other inlet cooling technologies with comparable performance enhancement. ISI allows the Trent 60 to maintain maximum rating over an extended operating range and provides considerable power boosts and heat rate improvements at high ambient temperatures. The ISI system provides staged inlet fogging and wet compression water streams to the gas turbine air intake system. The inlet fogging system provides a metered inlet fogging water flow to provide a controlled saturation of the intake with the air flow by three fogging arrays supplied in stages to provide maximum flexibility and control over the ambient temperature range. The wet compression system provides a metered wet compression water flow in three stages via spray rails mounted forward of the gas turbine LP compressor. The ISI operates to optimize unit efficiency and minimize water consumption at lower loads.



2-Stage Compression 3 Stage-Turbine

The specifications of the SCGS are provided in Table 3 below. The RR Trent 60 gas turbine uses water injection for NOx control prior to the SCR/CO Catalyst systems. The total net heat rate of the SCGS is 8,458 BTU/kWh based on the LHV at 78°F. Each Trent 60 will generate a maximum of 57 MW of electricity at 78°F. The total gross power generated by the SCGS will be 112 MW at 78°F.

Table 3 – SCGS Specifications

PARAMETERS	**SPECIFICATIONS**
Gas Turbine Manufacturer	Rolls Royce
Model No.	Trent 60
Fuel Type	CPUC Quality Natural Gas
Maximum Gas Turbine Heat Input	516 MMBTU/hr @ 78°F (HHV)
Maximum Gas Turbine Fuel Consumption	0.501 MMSCF/hr @ 78°F
Maximum Gas Turbine Exhaust Flow	256,795 DSCFM @ 78°F
Maximum Gas Turbine Exhaust Temperature	809°F @ 78 °F Ambient

NO_X Combustion Control	Water Injection
Ammonia Injection Rate	47 lb/hr at full load @ 78°F
Post Combustion Control	SCR and CO Catalyst
Net Plant Heat Rate, HHV	9,380 BTU/kWh @ 78°F
Net Plant Heat Rate, LHV	8,458 BTU/kWh @ 78°F
RR Trent 60 Gas Turbine Power Generation	57 MW @ 78°F
Total SCGS Gross Power Generation	112 MW @ 78°F[c]
[c] Represents the total power generated from two RR Trent 60 simple cycle gas turbines	

Table 4 – Auxiliary Boiler Specifications

PARAMETERS	**SPECIFICATIONS**
Boiler Manufacturer	Cleaver-Brooks
Model No.	D-Type NB-100D-40
Boiler Type	Watertube
Fuel Type	CPUC Quality Natural Gas
Maximum Fuel Consumption	0.035 MMSCF/hr
Maximum Gas Turbine Fuel Consumption	0.501 MMSCF/hr @ 78°F
Maximum Exhaust Flow	6,100 DSCFM
Maximum Exhaust Temperature	300°F
NO_X Combustion Control	Low NOx Burner
NOx BACT Concentration at Stack Outlet	5 ppmv @ 3% O_2
CO BACT Concentration at Stack Outlet	50 ppmv @ 3% O_2

Start-Up / Shutdown Schedule

El Segundo Power, LLC has proposed the following start-up / shutdown schedules for both the CCGS and the SSGS. For the CCGS, there will be a Fast Start and a Traditional start-up, the main difference being the amount of time needed to bring the GE 7FA gas turbine to full load and into compliance with the BACT limits[1]. Each start-up period is assumed to last 1-hour.

Table 4 – CCGS Start-Up / Shutdown Schedule

Event	Daily	Monthly	Annually
Fast Start[2]	1	47	150
Traditional Start-Up	1	15	50

[1] See Appendix A for a more detailed discussion regarding the Fast Start and Traditional Start-Up for the CCGS.

[2] Fast Start duration is 30 minutes. Therefore, the start-up hour for the Fast Start scenario will include 30 minutes of elevated emissions and 30 minutes of controlled emissions

Shutdown	2	62	200

Table 5 – SCGS Start-Up / Shutdown Schedule

Event	Daily	Monthly	Annually
Start-Up	4	60	480
Shutdown	4	60	480

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 nitrogen 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 generating system will use three SCR systems, one for the GE 7FA and one for each of the two Trent 60 gas turbines. The facility will use the existing ammonia storage tank to provide aqueous ammonia.

The GE 7FA gas turbine is equipped with dry low NOx (DLN) combustors. The NOx emissions from the GE 7FA are expected to be 9 ppmv on a dry basis at 15% O_2 prior to entry into the SCR unit. The SCR for the GE 7FA is designed to further reduce the gas turbine exhaust NOx emissions from 9.0 ppmv to 2.0 ppmv on a dry basis at 15% O_2. The SCR catalyst will be manufactured by Cormetech, Inc. The SCR catalyst will operate within an optimal temperature window of approximately 300°F to 750°F to facilitate a heterogeneous reaction between NO_X and ammonia (NH_3). The catalyst in the SCR is expected to be vanadium based on a homogeneous honeycomb titanium support matrix. The life cycle of the SCR modules is expected to be 5 years. After that the SCR catalyst may be returned to the vendor for reprocessing. The catalyst warranty 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 5 below is a summary of the specifications of the SCR catalyst for the CCGS.

Table 5 – CCGS SCR Catalyst Data Summary

PARAMETERS	**SPECIFICATIONS**
Catalyst Manufacturer	Cormetech, Inc.
Catalyst Description	Titanium/Vanadium/Tungsten (Ti-V-W)
Catalyst Volume	2,050 ft^3
Space Velocity	23,000 hr^{-1}
Ammonia Injection Rate	135 lb/hr of 29% aqueous NH_3 at full load
Ammonia Slip	5 ppmvd NH_3 at 15% O_2 1 hour average

Catalyst Life	5 Years
Maximum Operating Temperature	750°F
Stack Outlet NOx	2.0 ppmvd NOx at 15% O_2 1 hour average

The SCR catalysts for the two RR Trent 60 gas turbines will be identical and are expected to reduce the gas turbine exhaust NOx emissions from 25 ppmv to 2.5 ppmv, dry at 15% O_2. The SCR catalysts will be manufactured by Peerless. The catalyst material will be vanadium based on a homogeneous honeycomb titanium support matrix. The catalyst model number will be DNX629. The total catalyst volume is 1,272 ft^3. The catalyst dimensions will be 33'-0" high by 19'-6" wide by 2'-6" in length. The life cycle of the SCR modules is expected to be 5 years. After that the SCR catalyst may be returned to the vendor for reprocessing. The catalyst warranty is 2.5 ppmvd NO_X at 15% O_2, with 5 ppmvd NH_3 slip at 15% O_2 at dry conditions. The operating range for the SCR catalysts will be 600°F – 1,125°F. Table 6 below is a summary of the specifications of the SCR catalyst for the SCGS.

Table 6 – SCGS SCR Catalyst Data Summary

PARAMETERS	**SPECIFICATIONS**
Catalyst Manufacturer	Peerless
Catalyst Description	Titanium/Vanadium/Tungsten (Ti-V-W) with homogeneous honeycomb structure
Catalyst Volume	1,272 ft^3
Space Velocity	23,580 hr^{-1}
Ammonia Injection Rate	47 lb/hr of 29% aqueous NH_3 at full load
Ammonia Slip	5 ppmvd NH_3 at 15% O_2 1 hour average
Catalyst Life	5 Years
Maximum Operating Temperature	1,125°F
Stack Outlet NOx	2.5 ppmvd NOx at 15% O_2 1 hour average

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 gas turbine and at the upstream of the SCR catalyst. 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 one for the GE 7FA and one for each of the two Trent 60 gas turbines.

The oxidation catalyst for the GE 7FA gas turbine is designed to achieve a CO emission level of 2.0 ppmv and a VOC emission level of 2.0 ppmv, dry at 15% O_2. The gas turbine exhaust CO concentration is 4.4 ppmv, dry at 15% O_2, prior to entry into the oxidation catalyst. The oxidation catalyst will be manufactured by BASF. The catalyst dimensions will be 70'-0" high by 25'-0" wide. The following table lists the expected operating parameters of the oxidation catalyst. Table 7 below is a summary of the specifications of the oxidation catalyst for the CCGS.

Table 7 – CCGS Oxidation Catalyst Summary

PARAMETERS	**SPECIFICATIONS**
Catalyst Manufacturer	BASF
Catalyst Description	Platinum, corrugated SS substrate
Catalyst Volume	290 ft^3
Space Velocity	218,000 ft^{-1}
Stack Outlet CO	2.0 ppmvd CO at 15% O2, 1 hour average
Stack Outlet VOC	2.0 ppmvd CO at 15% O2, 1 hour average
Catalyst Life	5 years
Maximum Operating Temperature	1,000°F

The oxidation catalysts for the two RR Trent 60 gas turbines will be identical and are designed to achieve a CO emission level of 4.0 ppmv and a VOC emission level of 2.0 ppmv, dry at 15% O_2. The oxidation catalyst will be manufactured by Peerless. The catalyst reactors will be made of platinum group metals. The total catalyst volume will be 420 ft^3. The dimensions of the catalyst will be 33’ -0” high by 19’-5” wide. The oxidation catalyst will be operating within an optimal temperature window of approximately 600°F to 1,150°F. The following table lists the expected operating parameters of the oxidation catalyst. Table 8 below is a summary of the specifications of the oxidation catalyst for the SCGS.

Table 8 – SCGS Oxidation Catalyst Summary

PARAMETERS	**SPECIFICATIONS**
Catalyst Manufacturer	Peerless
Catalyst Description	Platinum group metals
Catalyst Volume	420 ft^3
Space Velocity	125,000 ft^{-1}
Stack Outlet CO	4.0 ppmvd CO at 15% O2, 1 hour average
Stack Outlet VOC	2.0 ppmvd CO at 15% O2, 1 hour average
Catalyst Life	5 years
Maximum Operating Temperature	1,200°F

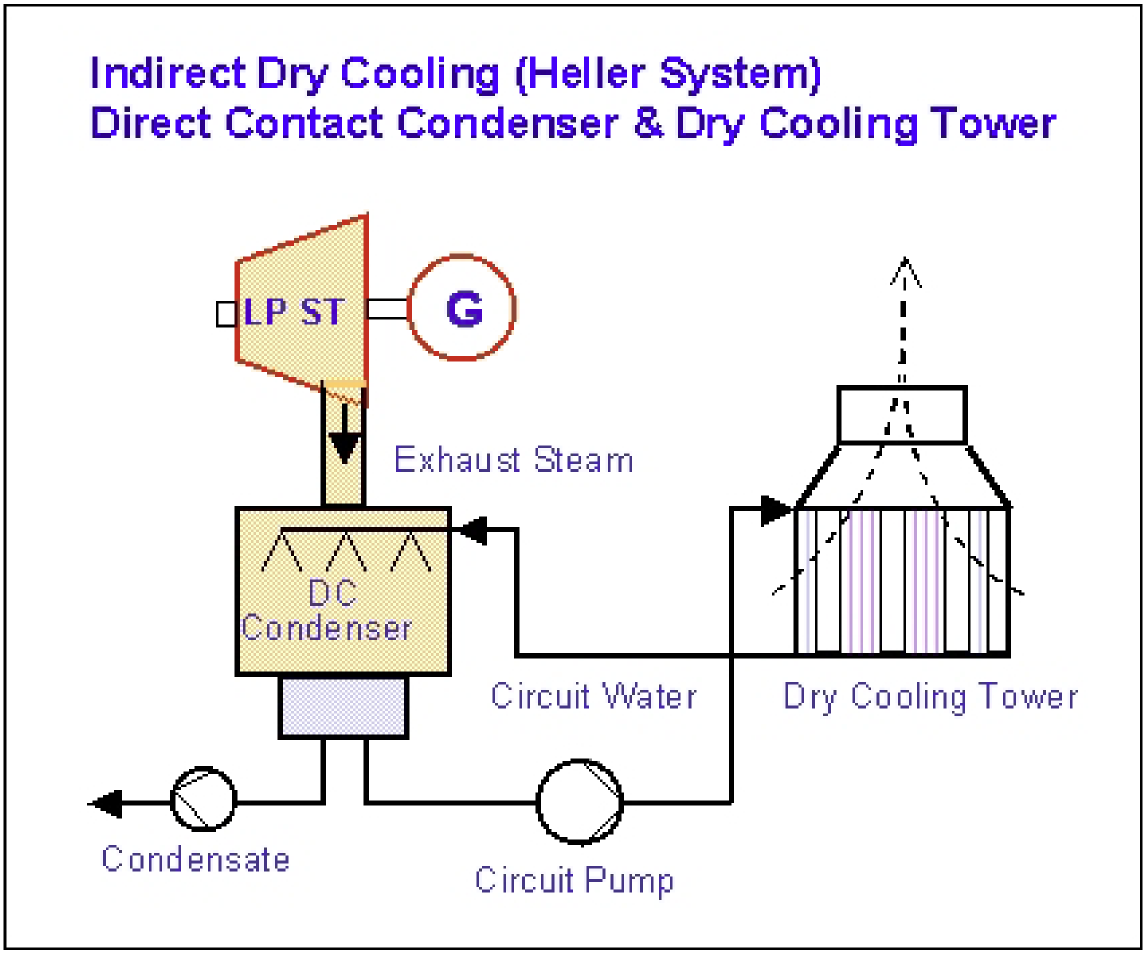
<u>Ammonia Injection Grid and Storage</u>

Aqueous ammonia (ammonium hydroxide at 29 percent nominal concentration by weight) is currently used in the SCRs serving the existing permitted (A/Ns 470652 and 470656) Siemens-Westinghouse Combined Cycle Gas Turbines #5 and #7 to reduce NO_X emissions to 2.0 ppmvd at 15% O_2. The ammonia is stored onsite in a permitted (P/N G20414) 20,000 gallon double walled underground storage tank. Ammonia will continue to be delivered to the site by truck and stored in the existing underground storage tank. Additional ammonia storage tanks are 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 for the CCGS and 1:1 molar ratio of ammonia to NO_X for the SCGS. Expected maximum ammonia use is about 18.7 gallons per hour for the CCGS, and 9.1 gallons per hour for each of the SCGS gas turbines. The estimated annual ammonia usage is 102,183 gallons for the CCGS assuming the annual capacity factor of 100%. The estimated annual ammonia usage is 43,527 gallons per CTG for the SCGS assuming the annual capacity factor of 55%. The new power system total ammonia usage is expected to be 189,237 gallons per year.

Heller System® Dry-Cooling

Cooling for the CCGS will utilize indirect cooling in which cooled condensate is circulated in a closed system that uses air as the secondary cooling medium. Exhaust steam from the steam turbine is condensed by direct contact with cooled condensate. Water from the direct contact jet condenser is divided into two streams. One water stream which is equal to the amount of condensate from the steam cycle, is pumped forward to be heated again in the HRSG. The second water stream is pumped to a dry cooling tower where it is cooled in non-evaporative water-to-air heat exchangers. The cooled water is then returned to the condenser where it is sprayed into and mixed with the exhaust stream. The steam condenses on the surface of the droplets and collects in the hotwell. The heat transfer between air and cooling water is achieved with convection rather than evaporation as in wet cooling systems. An additional advantage is that the Heller System does not require water to be replenished and consumes approximately 97 percent less water than wet cooling systems with minimal impact on plant performance. An illustrative schematic is provided below:



Stacks

The GE 7FA gas turbine and associated SCR/CO catalyst system uses a 210-foot tall, 20-foot diameter stack. The base elevation for the stack is 20 feet. The RR Trent 60 gas turbines and associated SCR/CO catalyst systems will each be equipped with their own individual 150-foot tall, 11.1 foot diameter stack. The base elevation for the SCGS stacks is 20 feet.

CAPACITY FACTOR

Operation of the CCGS is forecasted to be up to 60 percent capacity factor annually, including up to 200 startups per year and 200 shutdowns per year. The operation of the SCGS is forecasted to be up to 55 percent capacity factor annually, including 480 hours per year for startups and shutdowns per unit.

COMPLIANCE HISTORY

A review of the facility's compliance history in the last five years shows the following violations were issued to El Segundo Power, LLC:

- Notice to Comply (NC) #D03510 was issued on June 30, 2009 to ensure that missing data procedures are followed per 40 CFR 75 Subpart D, Section E when calculating substitute data. The facility was in compliance as of August 4, 2009.
- NC #D03513 was issued on August 4, 2009 to ensure that missing data procedures are followed per Rule 2012 Appendix A, Chapter 2, Section E when calculating substitute data. The facility was in compliance as of August 27, 2009.
- NC #D03517 was issued on December 23, 2009 to ensure that blended refinery-natural gas is sampled and analyzed for sulfur content at least once per month or once per batch per permit condition D90.1. The facility was in compliance as of January 5, 2010.
- NC #E01066 was issued to the facility on December 22, 2010 to provide any/all records for asbestos removal and demolition of both Boiler Unit #1 and Unit #2. The NC required the facility to also provide a list of company(s) involved in asbestos and demolition work on both Boiler Unit #1 and Boiler Unit #2. The facility was in compliance as of February 17, 2010.
- NOV #P53962 was issued to the facility on December 22, 2010 conducting the demolition of retired Boiler Unit #1 and Boiler Unit #2 without proper demolition notification. The NOV was also issued for excessive fugitive dust remaining visible in the atmosphere beyond the property line of the emission source. The facility is currently in compliance.
- NC #D20374 was issued on January 14, 2011 to submit copies of all contracts in which El Segundo Power, LLC allows access to and operation of their equipment by NRG El Segundo Operations, Inc., to verify who the operator is per Rule 203(a) ref. Rule 209. The facility is currently in compliance.
- NC #E00716 was issued on May 26, 2011 to report daily total emissions within 96-hour extension due to system failure and follow correct missing data procedures (MDP) in reporting daily total emissions when report is late. In addition, the facility was required to submit monthly emission reports aggregating NOx emissions from all major sources. The facility was in compliance as of June 10, 2011.
- Notice of Violation (NOV) #P52179 was issued to the facility on August 12, 2011 for failure to comply with the permit condition in which Devices D11 and D13 (Boiler Unit #3 and Boiler Unit #4, respectively) exceeded the NOx emission limit of 7 ppmv. This NOV was closed on March 26, 2013.
- NOV #P52185 was issued to the facility on May 8, 2012 for failure to comply with permit conditions D12.3, D12.5, and D12.6, which required the facility to conduct calibrations once every 12 months. This NOV was closed on March 26, 2013.

RETIREMENT OF BOILERS #3 & #4

Current SCAQMD policy for any facility wishing to seek exemption from the modeling and offset exemptions of Rule 1304(a)(2), is for the SCAQMD to require the submittal of and subsequent approval of a formal retirement plan for each affected unit prior to the construction of any new project. El Segundo Power, LLC is seeking an exemption from the modeling and offset requirements for the proposed ESPFM Project under the Utility Steam Boiler Replacement exemption of Rule 1304(a)(2). Therefore, El Segundo Power, LLC is required to submit a formal retirement plan to the SCAQMD for both Boiler Units #3 and #4.

Boiler #3 has been permanently retired from service and boiler #4 is currently in service at the facility and each was installed in the 1960s. Both of the boilers were originally designed to operate either with natural gas, refinery gas, or fuel oil. Currently, El Segundo Power, LLC is no longer accepting refinery gas from the Chevron facility and therefore boiler #4 is no longer burning refinery gas and is restricted to natural gas or fuel oil firing. The current specifications of each boiler are shown below:

Boiler #3:

Steam rate:	2,490,000 lb/hour
Fuel:	Natural Gas, Fuel Oil
Manufacturer:	Combustion Engineering
Heat input:	3,350 MMBTU/hr, equipped with 24 burners
Power output:	335 MW (gross)

Boiler #4:

Steam rate:	2,490,000 lb/hour
Fuel:	Natural Gas, Fuel Oil
Manufacturer:	Combustion Engineering
Heat input:	3,350 MMBTU/hr, equipped with 24 burners
Power output:	335 MW (gross)

As part of the offset package for the ESPR Project in which Gas Turbine Combined Cycle Units #5 and #7 (Devices D67 and D68) were issued Permits to Construct under A/Ns 470652 and 470656, El Segundo Power, LLC is required by Facility Permit Condition E193.3 to surrender the Permit to Operate (P/N F14448) for Boiler Unit #3 within 90 days of the initial start-up Gas Turbine Combined Cycle Units 5 and 7. The initial start-up date for Gas Turbine Unit #5 was April 24, 2013. The initial start-up date for Gas Turbine Unit #7 was April 9, 2013. El Segundo Power, LLC has permanently retired Boiler Unit #3 from service. The Permit to Operate for Boiler #3 was surrendered to the SCAQMD on July 23, 2013. SCAQMD policy requires that retirement of utility boilers must result in the equipment being permanently inoperable and therefore must consist of the following minimum conditions:

1. Each of the burners currently attached to the boiler must be removed from the boiler in their entirety. This not only includes the main burner assembly, but also all of the associated

igniters, electronic or other ignition devices (if applicable), fuel nozzles, V-cones and well as any other devices related to the burner structure or operation.

2. A significant portion of each of the fuel supply lines which supply natural gas to the boiler/burner assembly must be disconnected from the boiler/burner assembly, including all fuel lines which are accessible. In addition, each of these fuel lines remaining sections must be filled with a suitable amount of concrete to prevent delivery of fuel. In addition, all remaining fuel line~~s~~ sections leading to the boiler must be flanged so as to render the lines incapable of accepting fuel.

3. The boiler feedwater pump must be disconnected and removed from the system so as to ensure that the boiler is not capable of receiving feedwater.

El Segundo Power, LLC will provide a revised retirement plan for Boiler No. 3 which will address and incorporate in sufficient detail, the requirements in items 1, 2, and 3 above, prior to issuance of Permits to Construct for the ESPFM Project.

Boiler Unit #4 is currently in operation and, in accordance with the California State Water Resources Board's Once-Through Cooling (OTC) policy, is scheduled to be permanently retired by December 31, 2015, or within 90 days of the initial start-up of the proposed ESPFM Project, whichever occurs sooner. The retirement of Boiler Unit #4 will result in a reduction in 335 MW of electrical generating capacity which will be used to partially offset emissions from the proposed ESPFM Project. El Segundo Power, LLC will provide a retirement plan for Boiler No. 4 which will address and incorporate in sufficient detail the requirements listed in items 1,2, and 3 above.

The next three pages show the process flow diagrams for the CCGS, the SCGS and the layout of the El Segundo Power, LLC site.

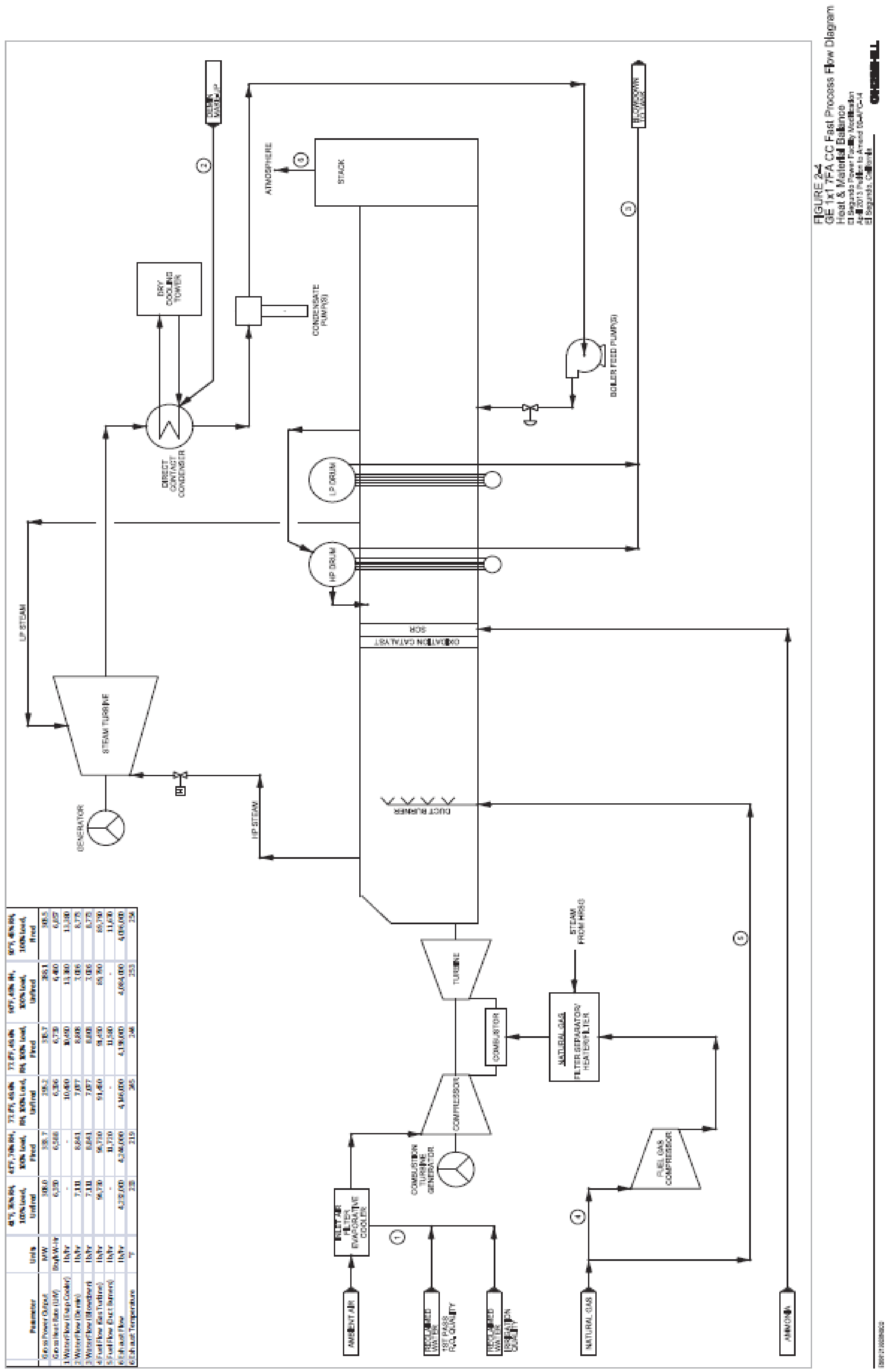
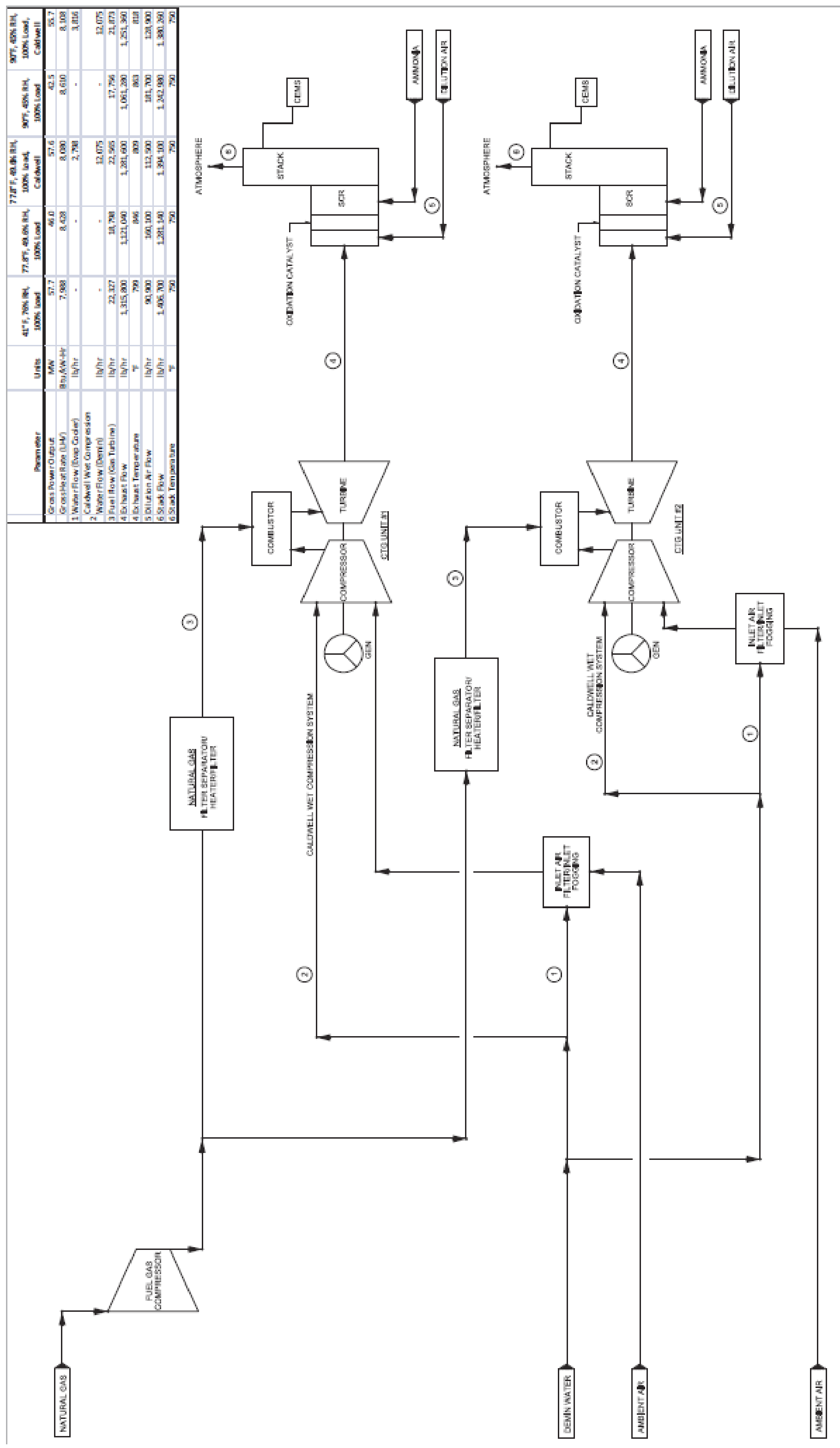


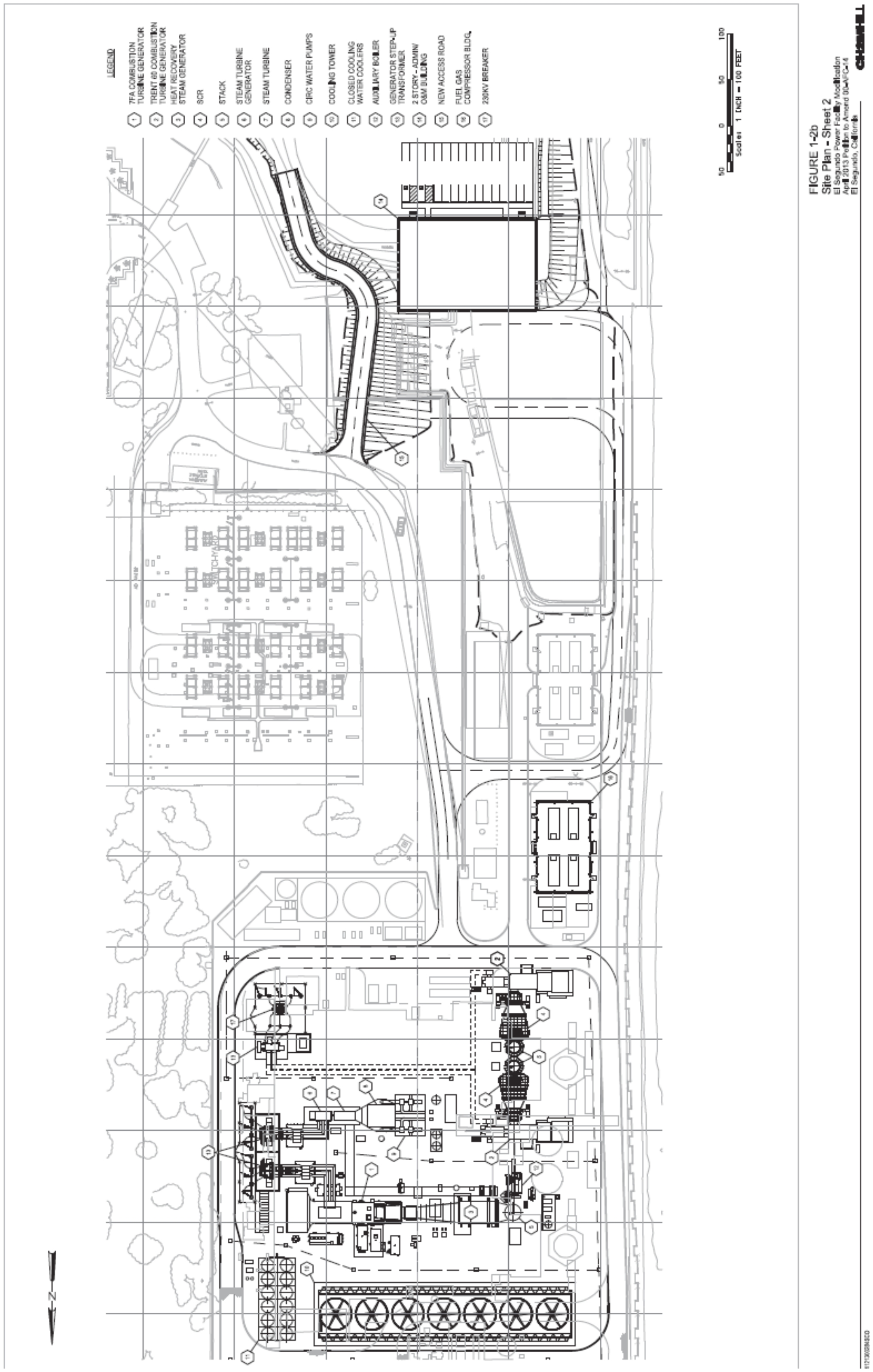
FIGURE 2-4
GE 1x1 7FA CC Fast Process Flow Diagram
Heat & Material Balance
El Segundo Power Facility Modification
April 2013 Petition to Amend 00-AFC-14
El Segundo, California
STACK
ATMOSPHERE
DRY COOLING TOWER
CONDENSATE PUMP(S)
DIRECT CONTACT CONDENSER
BOILER FEED PUMP(S)
LP DRUM
HP DRUM
SCR
OXIDATION CATALYST
DUCT BURNER
LP STEAM
HP STEAM
STEAM TURBINE
GENERATOR
TURBINE
COMBUSTOR
COMPRESSOR
COMBUSTION TURBINE GENERATOR
NATURAL GAS FILTER SEPARATOR/ HEATER/FILTER
STEAM FROM HRSG
FUEL GAS COMPRESSOR
INLET AIR FILTER EVAPORATIVE COOLER
AMBIENT AIR
NATURAL GAS
AMMONIA



	Parameter	Units	41° F, 76% RH, 100% Load	77.8°F, 49.6% RH, 100% Load	77.8° F, 49.6% RH, 100% Load, Caldwell	90°F, 45% RH, 100% Load	90°F, 45% RH, 100% Load, Caldwell
	Gross Power Output	MW	57.7	46.0	57.6	42.5	55.7
	Gross Heat Rate (LHV)	Btu/kW-Hr	7,988	8,428	8,080	8,610	8,108
1	Water Flow (Evap Cooler)	lb/hr	-	-	2,798	-	3,816
2	Caldwell Wet Compression Water Flow (Demin)	lb/hr	-	-	12,075	-	12,075
3	Fuel flow (Gas Turbine)	lb/hr	22,327	18,798	22,565	17,756	21,873
4	Exhaust Flow	lb/hr	1,315,800	1,121,040	1,281,600	1,061,280	1,251,360
4	Exhaust Temperature	°F	799	846	809	863	818
5	Dilution Air Flow	lb/hr	90,900	160,100	112,500	181,700	128,900
6	Stack Flow	lb/hr	1,406,700	1,281,140	1,394,100	1,242,980	1,380,260
6	Stack Temperature	°F	750	750	750	750	750

FIGURE 2-5
Rolls Royce Trent 60 Process Flow Diagram
Heat & Material Balance
El Segundo Power Facility Modification
April 2013 Petition to Amend 00-AFC-14
El Segundo, California

CH2MHILL



LEGEND
1 7FA COMBUSTION TURBINE GENERATOR
2 TRENT 60 COMBUSTION TURBINE GENERATOR
3 HEAT RECOVERY STEAM GENERATOR
4 SCR
5 STACK
6 STEAM TURBINE GENERATOR
7 STEAM TURBINE
8 CONDENSER
9 CIRC WATER PUMPS
10 COOLING TOWER
11 CLOSED COOLING WATER COOLERS
12 AUXILIARY BOILER
13 GENERATOR STEP-UP TRANSFORMER
14 2 STORY - ADMIN/ O&M BUILDING
15 NEW ACCESS ROAD
16 FUEL GAS COMPRESSOR BLDG.
17 230KV BREAKER
50 0 50 100
Scale: 1 INCH = 100 FEET
FIGURE 1-2b
Site Plan - Sheet 2
El Segundo Power Facility Modification
April 2013 Petition to Amend 00-AFC-14
El Segundo, California

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 of the emissions 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 1 – Criteria Pollutants Potential to Emit – 30 Day Averages

Equipment	NOx	CO	VOC	PM10	SOx
Unit 9 – GE 7FA(1) (lb/day)	1,429.90	1,276.67	234.50	248.33	98.83
Unit 9 – Duct Burner(3) (lb/day)	48.67	29.68	17.03	42.83	3.79
Unit 11 – RR Trent 60(2) (lb/day)	417.75	1,118.56	100.31	96.63	6.51
Unit 12 – RR Trent 602) (lb/day)	417.75	1,118.56	100.31	96.63	6.51
Auxiliary Boiler(4) (lb/day)	1.44	8.22	0.63	1.89	0.13

(1) Page 80, Table A-14, Appendix A, includes turbine commissioning
(2) Page 90, Table B-13, Appendix B, includes turbine commissioning
(3) Page 93, Table C-1, Appendix C
(4) Page 94, Table C-2, Appendix C

Table 2 – Maximum Daily Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Unit 9 – GE 7FA(1) (lb/day)	536.07	1,308.77	232.84	228.00	28.32	392.40
Unit 9 – Duct Burner(3) (lb/day)	48.67	29.68	17.03	42.83	3.79	N/A
Unit 11– RR Trent 60(2) (lb/day)	239.2	686.12	73.09	120.0	6.9	84.72
Unit 12– RR Trent 60(2) (lb/day)	239.2	686.12	73.09	120.0	6.9	84.72
Auxiliary Boiler(4) (lb/day)	1.44	8.22	0.63	1.89	0.13	N/A
New Equipment Total (lb/day)	1,064.60	2,719.52	396.35	512.36	47.17	561.84
New Equipment Total (ton/day)	0.533	1.36	0.198	0.256	0.024	0.281

(1) Page 77, Table A-8, Appendix A, includes turbine commissioning

(2) Page 86, Table B-7, Appendix B, includes turbine commissioning
(3) Page 93, Table C-1, Appendix C
(4) Page 94, Table C-2, Appendix C

Table 3 – Monthly Total Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Unit 9 – GE 7FA(1) (lb/month)	16,093.00	38,300.00	7,035.00	6,937.00	831.00	11,934.00
Unit 9 – Duct Burner(3) (lb/month)	1,460.00	890.60	511.00	1,284.80	113.80	N/A
Unit 11 – RR Trent 60(2) (lb/month)	3,969.82	10,663.12	1,202.60	2,199.60	130.18	1,376.42
Unit 11 – RR Trent 60(2) (lb/month)	3,969.82	10,663.12	1,202.60	2,199.60	130.18	1,376.42
Auxiliary Boiler(4) (lb/month)	44.21	251.47	19.34	58.03	3.94	N/A
New Equipment Total (lb/month)	25,536.11	60,781.70	9,960.20	12,666.90	1,242.81	14,686.84
New Equipment Total (ton/month)	12.76	30.39	4.98	6.33	0.621	7.34

(1) Page 77, Table A-9, Appendix A
(2) Page 87, Table B-8, Appendix B
(3) Page 93, Table C-1, Appendix C
(4) Page 94, Table C-2, Appendix C

Table 4 – Annual Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Unit 9 – GE 7FA(1) (ton/year)	53.43	78.60	20.89	25.92	3.295	41.33
Unit 9 – Duct Burner(3) (ton/year)	5.45	3.33	1.91	4.80	0.426	N/A
Unit 11 – RR Trent 60(2) (ton/year)	18.94	45.63	5.66	12.00	0.70	7.76
Unit 11 – RR Trent 60(2) (ton/year)	18.94	45.63	5.66	12.00	0.70	7.76
Auxiliary Boiler(4) (ton/year)	0.26	1.48	0.11	0.34	0.02	N/A
New Equipment Total (ton/year)	97.01	174.75	34.17	54.99	5.34	56.85

(1) Page 80, Table A-13, Appendix A
(2) Page 88, Table B-11, Appendix B
(3) Page 93, Table C-1, Appendix C
(4) Page 94, Table C-2, Appendix C

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 5 – Hazardous Air Pollutants Emissions per Year

	HAP (tons/year)
Unit 9 – GE 7FA + DB	8.35
Unit 11 – RR Trent 60	1.57
Unit 12 – RR Trent 60	1.57
Auxiliary Boiler	0.08
Project Total	11.57

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 6 – Greenhouse Gas Emissions from the New Equipment

	Daily CO2e (tons/day)	Monthly CO2e (tons/month)	Annual CO2e (tons/year)
Unit 9 – GE 7FA + DB	3,413.00	90,426.20	763,683.51
Unit 11 – RR Trent 60	722.87	12,801.79	140,999.49
Unit 12 – RR Trent 60	722.87	12,801.79	140,999.49
Auxiliary Boiler	50.34	1,560.39	18,402.54
ESPFM Project Total	4,909.08	117,590.17	1,064,085.03

RULES EVALUATION

California Environmental Quality Act (CEQA)

The California Energy Commission (CEC) is the lead agency for the ESPFM Project (00-AFC-14C), and will be addressing CEQA compliance. CEC's process will fully evaluate all air quality impacts for the entire project. It is anticipated that the CEC will amend its decision dated February 2, 2005 to address the changes proposed under the ESPFM Project.

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 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 RR Trent 60 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 (1.26 lb/222 MWh). The RR Trent 60 gas turbines will have a NOx limit of 2.5 ppmv, and a SO_2 limit equivalent to 0.005 lb/MWhr (0.30 lb/57 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). El Segundo Power, LLC 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. El Segundo Power, LLC 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.

40CFR Part 63 Subpart YYYY – NESHAP for Gas Turbines

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 26.55 tons per year. Thus, El Segundo Power, LLC is a major source facility, and is subject to the requirements of this subpart. §63.6100 of 40CFR Part 63 Subpart YYYY requires gas turbines to comply with a formaldehyde emission limit in Table 1 of 91 ppbvd measured at 15% O2. In addition, §63.6100 of 40CFR 63 Subpart YYYY requires an operating limitation in Table 2 such that the operator of the equipment maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.
The applicable equipment will be conditioned to comply with these requirements.

40CFR Part 64 – Compliance Assurance Monitoring (CAM)

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. 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 El Segundo Power, LLC 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 300°F and 750°F for the CCGS, and between 600°F and 1,125°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. In addition the operator will conduct periodic source testing. Compliance is expected.

40CFR Part 72 – Acid Rain

El Segundo Power, LLC currently has SO_2 allocations under the acid rain program, allocated to their Boilers 1 through 4 in Facility Permit Condition F18.1. 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, El Segundo Power, LLC will obtain the credits from the SO_2 trading market. Based on the above, compliance with this rule is expected.

RULE 212 – Standards for Approving Permits

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 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 EPA Region IX 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.

<u>RULE 218 – Continuous Emission Monitoring</u>
This rule applies to the CO CEMS, which is required to verify CO emission levels from each gas turbine. El Segundo Power, LLC 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.

<u>RULE 401 – Visible Emissions</u>
Visible emissions from the three gas turbines and the auxiliary boiler are not expected since each will be fired exclusively with pipeline quality natural gas and each device will use BACT . Compliance with this rule is expected.

<u>RULE 402 – Nuisance</u>
Nuisance problems are not expected under normal operating conditions of the gas turbines and the auxiliary boiler. 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 2 ppmv for the CCGS and no more than 4 ppmv for the SCGS. The auxiliary boiler will comply with a CO emission limit of 50 ppmv. Compliance with CO will also be verified through the CEMS data for the gas turbines.

RULE 409 – Combustion Contaminants
This rule applies to the gas turbines and auxiliary boiler. 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 = 9.5 lbs/hr
CO_2 = 4.82% in the exhaust
Exhaust flow = 51.55 MMSCF/hr

$$PM = \frac{9.5*7000*12/4.82}{51.55*10^6} = 0.003 \text{ grains/dscf}$$

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

PM = 5.0 lbs/hr
CO_2 = 3.43% in the exhaust
Exhaust flow = 15.41 MMSCF/hr

$$PM = \frac{5.0*7000*12/3.43}{15.41*10^6} = 0.008 \text{ grains/dscf}$$

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 El Segundo Power, LLC 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 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 the Rule 409 evaluation PM10 emissions are 0.003 gr/dscf for the CCGS turbine, and 0.008 gr/dscf for the SCGS gas turbines. 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. CO and NO_2 are reviewed under PSD because they are attainment pollutants. NOx is also reviewed under RECLAIM. NSR includes requirements of Best Available Control Technology (BACT), modeling analysis, and offset. NH_3 is subject to BACT requirements only.

Best Available Control Technology (BACT)

BACT is defined in SCAQMD Rule 1301 as 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

BACT/LAER for the CCGS combined cycle gas turbine is determined by following the above definitions:

VOC: A review of recently issued combined cycle gas turbines permits nationwide indicates that the most stringent VOC emission limit for combined cycle gas turbines is 2.0 ppmv based on 1-hour average, dry at 15% O_2. In 2013 LADWP was permitted with a VOC BACT limit at 2.0 ppmv based on a 1-hour average. 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 SCAQMD's BACT requirement for combined cycle gas turbines.

The following is the SCAQMD determined BACT/LAER limits:

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

El Segundo Power, LLC 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. El Segundo Power, LLC has proposed to limit the NH_3 slip limit to 5 ppmv. Compliance is expected.

<u>SCGS</u>

BACT/LAER for the SCGS gas turbines are also determined by following the above definitions:

VOC: A review of recently issued simple cycle gas turbines permits nationwide indicates 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 and Scattergood Generating Stations as well as the gas turbines permitted at the City of Riverside are permitted at 2.0 ppmv based on a 1-hour average. The 2.0 ppmv limit is consistent with SCAQMD's BACT requirement for simple cycle gas turbine generators.

The following is the SCAQMD determined BACT/LAER limits:

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

El Segundo Power, LLC has proposed to use the same emission limits for the RR Trent 60 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. El Segundo Power, LLC has proposed to limit the NH_3 slip limit to 5 ppmv. Compliance is expected.

Auxiliary Boiler

SCAQMD's BACT/LAER determination for a natural gas fired auxiliary boiler is based on the use of pipeline quality natural gas for both VOC. El Segundo Power, LLC will use pipeline quality natural gas with this boiler. Compliance is expected.

Modeling Analysis

PM10 was designated as an federal attainment pollutant in the SCAB on June 26, 2013. However, PM10 remains non-attainment at the state level and will be evaluated under NSR as well. As such, modeling analysis is required for 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. CO is currently in attainment at the federal and state levels. Therefore, the CO emissions from the proposed project will be addressed under Regulation XVII – Prevention of Significant Deterioration (PSD).

Maximum project impacts from PM10 emissions were determined by using the AERMOD model, version 12345. The representative meteorological data used in the model are from the Los Angeles International Airport. Modeling analysis were performed for startup, shutdown, commissioning, and normal operations. El Segundo Power, LLC submitted the air quality modeling analysis in March 2013 to the District for review. The District found the analysis acceptable for Rule 1303 requirements. Modeling on an individual equipment basis is currently being conducted by the applicant and the results will be forwarded to SCAQMD when completed.

A variety of operating scenarios of the three gas turbines and the auxiliary boiler are modeled to determine the worst air quality impact for PM10. The applicant has determined that the peak 24-hour and annual PM10 impacts from the proposed project occur during the turbine commissioning period. The next table shows the maximum impacts from the modeling results and the applicable PM10 emissions standards.

Table 7 – New Source Review Modeling – PM10 Emissions

Pollutants	Averaging Time	ESPFM Model Results (μg/m^3)	Significant Change Threshold (μg/m^3)	Significant (Yes/No)
PM10	24-hour	1.8	2.5	No
	Annual	0.3	1.0	No

Both the 24-hour average and the annual average PM10 emissions are below the respective significant change thresholds.

El Segundo Power, LLC submitted the air quality modeling analysis in March 2013 to the SCAQMD for review. The SCAQMD found the analysis acceptable for Rule 1303 requirements.

Offsets

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. The two RR Trent 60 gas turbines are simple cycle gas turbines. SCAQMD Rule 1135 defines advance combustion sources as those which emit NOx at no greater than 0.10 lb/net MWH on a daily average basis, excluding commissioning, start-up and shutdown periods, if the source is located within the South Coast Air Basin. The proposed RR Trent 60 simple cycle gas turbines will emit 0.091 lb/net MWH under baseload conditions, as shown in Table 10, Appendix B page 91. Therefore, the two RR Trent 60 simple cycle gas turbines qualify as advanced gas turbines, and replacement of Boilers #3 and #4 with Trent 60 simple cycle 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 334 gross megawatts. The SCGS has a combined power rating of 112 gross megawatts. The total power generating capacity will be 447 MW. Boiler #3 was retired from service with 112 MW of unused credits. These credits will be combined with the 335 MW from the permanent retirement of Boiler #4 for a total of 447 MW which will completely offset the emissions from the ESPFM Project. 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. However, the auxiliary boiler is not exempt under Rule 1304(a)(2) and is required to provide the following offsets as shown in Table 8:

Table 8 – Required Offsets:

Auxiliary Boiler	VOC	PM10	SOx
30 Day Average, lb/day	0.63	1.89	0.13
1.2 Offset Factor	1.2	1.2	1.2
Required Offsets	1	2	None

Rule 1304.1 – Electrical Generating Fee for Use of Offset Exemption

This rule requires electrical generating facilities which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay fees for up to the full amount of offsets provided by the SCAQMD. El Segundo Power, LLC will be required to demonstrate compliance with the specific requirements of this rule prior to the issuance of the Permits to Construct for the ESPFM Project.

RULE 1325 – Federal PM2.5 New Source Review Program
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 a potential to emit of greater than 100 tons per year. A major polluting facility is required to comply with the following requirements:

- 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

As shown in Appendix F, the total PM2.5 potential to emit resulting from the addition of the GE Combined Cycle Gas Turbine, the two RR Trent 60 Simple Cycle Gas Turbines, the Auxiliary Boiler, and the subsequent retirement of Boilers #3 and #4 will not result in an emissions increase above the 100 ton/year threshold. Therefore, El Segundo Power, LLC will continue to be a non-major polluting facility for PM2.5. The detailed calculations are included in the Appendix F.1.

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:	$\leq$ 1 in 1 million (1.0×10^{-6})
MICR, with T-BACT:	$\leq$ 10 in 1 million (1.0×10^{-5})
Cancer Burden:	$\leq$ 0.5
Maximum Chronic Hazard Index:	$\leq$ 1.0
Maximum Acute Hazard Index:	$\leq$ 1.0

El Segundo Power, LLC performed a Health Risk Assessment (HRA) for the cumulative impact of the proposed project using the HARP Model (version 1.4f). The results include the facility-wide HRA from existing gas turbines #5 and #7 and the proposed gas turbines #9, #11, #12, and the 36 MMBTU/hr auxiliary boiler. The results are presented below in Table 9:

Table 9 – Facility-wide HRA

Risk Parameter[a]	Residential[b]	Commercial	Rule 1401 Thresholds
MICR	0.31EE-6	0.06EE-6	1EE-6
HIA (Case 1)[c]	1.3EE-2	N/A	1.0
HIA (Case 2)[c]	0.9EE-2	N/A	1.0
HIC	6.7EE-3	N/A	1.0

[a] MICR=Maximum Individual Cancer Risk; HIA=Acute Hazard Index; HIC=Chronic Hazard Index
[b] Residential impacts for MICR; maximum impact for other health risks
[c] Acute impact modeling scenarios: Case 1: All Gas Turbines in operation, Auxiliary Boiler not operating; Case 2: Units 11 and 12 and Auxiliary Boiler operating, Unit 9 not operating

Results of the analysis show that the highest estimated MICR is 0.31 in a million, which is below the Rule 1401 threshold of 1 in a million. The highest estimated acute hazard index is 0.0013, less than the rule threshold of 1.0. In addition, the highest estimated chronic hazard index is 0.0067, which is also less than the rule threshold 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 El Segundo Power, LLC. The District considers the modeling approach and methodology are consistent with SCAQMD Rule 1401. The modeling results are acceptable.

<u>Regulation XVII – Prevention of Significant Deterioration – Criteria Pollutants</u>
The SCAQMD and the EPA has entered into an agreement on July 25, 2007 that SCAQMD is re-delegated a partial PSD authority. SCAQMD is authorized to issue new and modified PSD permits in accordance with SCAQMD's Regulation XVII.

The SCAB is in attainment for NO_2, SO_2, CO, and PM10 emissions. Therefore, this regulation applies to NO_2, SO_2, CO, and PM10 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 ppmvd, 1-hour average at 15% O_2 for the CCGS gas turbine, and 2.5 ppmvd, 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. The Auxiliary Boiler is required to comply with a 5 ppmvd limit measured at 3% O2. Compliance is expected.
- SO_2 – The requirement is to use pipeline quality natural gas. El Segundo Power, LLC will use pipeline quality natural gas for the Gas Turbines and Auxiliary Boiler. Compliance is expected.

- CO – The most stringent emission limit is 2.0 ppmvd based on 1-hour average at 15% O_2 for a combined cycle gas turbine, 4.0 ppmvd based on 1-hour average at 15% O_2 for a simple cycle gas turbine. Therefore, the BACT limit is set at 2 ppmvd for the CCGS and 4 ppmv for the SCGS. El Segundo Power, LLC has proposed the same emission limits. The Auxiliary Boiler is required to comply with a 50 ppmvd CO emission limit measured at 3% O2. Compliance is expected.
- PM10 – Use of natural gas with a sulfur content (calculated as H_2S) less than 1 grain per 100 scf. The project will use pipeline quality natural gas. Compliance is expected.

In addition to the BACT requirement, a PSD Analysis is required for a significant increase of emissions. El Segundo Power, LLC 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 10 – Potential to Emit of the New Equipment

Pollutant	CCGS(1)	SCGS(2) (two units)	Auxiliary Boiler	Duct Burner	Total
CO (tons/year)	78.60	45.63	1.56	3.33	129.12
NO_2 (tons/year)	53.43	18.94	0.45	5.45	78.27
SO_2 (tons/year)	3.30	0.70	0.22	0.426	4.65

(1) Page 79, Table A-12, Appendix A
(2) Page 88, Table B-11, Appendix B

Table 11 – Emission Change Summary

Pollutant	New Power System (tons/yr)	Significance Threshold (tons/yr)	PSD Analysis Required (Yes/No)
CO	129.12	100	Yes
NO_2	78.27	40	Yes
SO_2	4.65	40	No

PSD analysis is required for NO_2 and CO.

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

- 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:

Gerardo Rios, US EPA, Region IX
John Notar, Federal Land Manager, National Park Service (NPS)
Mike McCorison, Air Quality Specialist, USDA Forest Services

Final permit action regarding PSD is dependent on comments received from the NPS and the USDA Forest Service. Final comments from the Federal Land Managers is pending.

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 $\mu g/m^3$, annual average
CO: 575 $\mu g/m^3$, 8-hour average

The applicant submitted modeling results that showed the maximum NO_2 impact of 0.50 $\mu g/m^3$ annual average and a maximum CO impact of 12.2 $\mu g/m^3$ 8-hour average. Since these levels do not exceed the preconstruction monitoring thresholds, preconstruction monitoring is not required.

2. Assessment of significance under PSD

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

NO_2: 7.5 $\mu g/m^3$, 1-hour average
NO_2: 1.0 $\mu g/m^3$, annual average
CO: 2,000 $\mu g/m^3$, 1-hour average
CO: 500 $\mu g/m^3$, annual average
PM10: 5.0 $\mu g/m^3$, 24-hour average

The 1-hour NO2 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 modeled impacts are shown below in Table 12:

Table 12 – Modeled Impacts

Pollutant	Averaging Period	Maximum Impact, μg/m^3	PSD SIL μg/m^3	Exceedance (Yes/No)
NO2	1-hour	23.1[a]	7.5	Yes
	Annual	0.5	1.0	No
CO	1-hour	109.0	2,000	No
	8-hour	12.2	500	No
PM10	24-hour	1.8	5.0	No
[a]Reported results reflect start-up conditions				

The 1-hour NO2 average impact for the ESPFM Project exceeds the PSD SIL of 7.5 μg/m^3 based on a 1-hour average. Therefore, a cumulative impact analysis is required to demonstrate that the ESPFM Project will not cause a new or make significantly worse, an existing 1-hour NO2 violation of the National Ambient Air Quality Standards (NAAQS). On July 31, 2013, the applicant submitted a cumulative impact analysis which included the impacts from the existing Units 5 and 7 of the El Segundo Power Redevelopment Project, Chevron Refinery, and the LADWP Scattergood Generating Station. At the request of the SCAQMD and CEC staff, the impacts from the AES Redondo Beach and the ExxonMobil Refinery facilities as well as the impacts from simultaneous start-up of the three proposed turbines of the ESPFM Project were included in the cumulative modeling analysis. The inclusion of the impacts from these sources resulted in no effect on the cumulative impact results. Dispersion modeling using AERMOD and its output option MAXDCONT shows that the peak contribution from the ESPFM Project to a modeled violation of the 1-hour NO2 NAAQS is 3.38 μg/m^3 which is less than the SIL and thus insignificant. Therefore, the proposed ESPFM Project will not cause a new, or make significantly worse, an existing 1-hour NO2 violation of the NAAQS.

The District modeling staff has reviewed the applicant's approach and methodology with respect to the cumulative impact analysis and has determined that the approach and methodology are acceptable. The results of the cumulative impact analysis are shown in the table below in Table 13.

Table 13 – Cumulative Impact Analysis*

Modeling Results: Maximum 1-hour Average NO2 Impacts					
Combustion Sources	Maximum 1-hour Average NO2 Concentration, μg/m^3				
	2005	2006	2007	2008	2009
ESP Units 9, 11,& 12	24.1	23.5	24.4	25.1	24.5
ESP Units 5 & 7	1.8	1.7	1.8	1.9	1.8
All 5 ESP Units	24.4	23.6	24.67	25.2	24.8
Chevron Refinery	691.1	546.5	688.4	523.3	709.8
LADWP Scattergood	5.7	5.6	5.7	5.7	5.9
AES Redondo Beach	2.2	2.2	2.2	2.2	2.2
Background[†]	109.6	109.6	109.6	109.6	109.6

All Sources+ Background	753.1	619.7	750.5	618.9	771.8
*Table 13 shows the maximum result in the project impact area for each individual category of combustion source for each calendar year of meteorological data. The maximum impacts from all sources do not occur at the same place and time. As a result, the maximum overall impacts (All Sources + Background) are less than the sum of the individual impacts. †The background concentration for each hour is based on a seasonal daily profile provided by the District. Each hour of the profile is the 3rd highest measured value for that clock hour and season. The background concentration was not adjusted to account for the modeled impact of existing sources. (i.e. Chevron) at the monitoring site.					

3. 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 ESPFM Project:

San Gabriel Wilderness Area (53 km)
Cucamonga Wilderness Area (78 km)

The area impacted by the project is heavily industrialized and has no vegetation of commercial or recreational value. Minimal vegetation exists within the facility. 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. Both the San Gabriel and Cucamonga Wilderness Areas are located at a distance greater than 50 km from the ESPFM Project site. Therefore, no further modeling was required for PSD increment analysis.

The visibility impact analysis required by Rules 1703(a)(3)(E) requires assessment of the impairment to visibility in the area surrounding the project (Class II Visibility Impairment Analysis). The applicant has conducted a Class II Visibility Impairment Analysis for the four Class II State Parks (Dockweiler State Beach, Will Rogers State Historic Park, Kenneth Hahn State Historic Park, and Santa Monica State Beach) within the 20 km from the ESPFM Project site. SCAQMD Modeling staff have reviewed the applicant's analysis and have determined that the approach and methodology are acceptable.

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.

DETERMINE GHG 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

El Segundo Power, LLC is an existing PSD major source because of its NOx and CO emissions. The new power system will have more than 75,000 tons per year CO2e emissions, as calculated in Appendix E. 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, based on a recent similar analysis conducted for LADWP Scattergood Generating Station, 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 ESPFM Project may be the old petroleum production area in Long Beach, a formation in the Lower San Joaquin Valley, and possibly 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 on the demand 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. Demand response programs include increasing the efficiency of El Segundo Power, LLC's 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. 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 Fast Start Process (Fast Start®) to minimize emissions during startup and increase the efficiency of the power plant. El Segundo Power, LLC plans to use the CCGS in the base load operation. The SCGS compliments the CCGS by providing demand-following capability. The two RR Trent 60 units have the some of the highest thermal efficiencies (48%) 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 ESPFM Project 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 El Segundo Power, LLC's electricity system operation and thereby reduce GHG emissions.

Step 2 Eliminate Technically Infeasible Options

The second step for the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to 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. Carbon Capture and Sequestration (CCS)

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 ESPFM Project. 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 ESPFM project.

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 a low load factor of 45%, the CCGS will emit CO_2 at a rate of 967.10 lb CO_2 per net megawatt hour. The GHG emissions will be 876.89 lbs CO_2 per net megawatt hour when the load factor improves to 100%. Therefore, the GHG emissions is expected to be at 967-877 pounds CO_2 per net MWh if the CCGS operates between the load factor of 45%-100%. 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 RR Trent 60 is an advanced simple cycle gas turbine generator that incorporates water injection at the compression stage to promote enhanced energy efficiency. The heat rate of the RR

Trent 60 is approximately 8,400 – 9,400 Btu/kWh well 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 1,502 – 1,113 lbs CO2 per net megawatt hour depending on load factors. The power plant operations include normal operation, startup operation, and shutdown operation.

The use of an advanced commercially available simple-cycle gas turbine such as the Trent 60 combined with good combustion operation and maintenance to maintain optimum efficiency, is determined to be BACT for GHG for the ESPFM Project.

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.

Step 3 - Rank Remaining Control Technologies

While carbon capture and sequestration (CCS) was determined to be technically infeasible for the ESPFM 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 ESPFM Project. 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 ESPFM Project it is not evaluated under this step.

B. Thermal Efficiency

The database review of BACT determinations described above identified six 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.
- SCAQMD issued the PSD Permits for the LADWP Scattergood Generating Station in 2013. The project consists of one GE 7FA combined cycle gas turbine and two simple cycle GE LMS100 generators. EPA concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.
- SCAQMD issued the PSD Permit for the City of Pasadena in 2013. The project consists of one LM6000 combined cycle gas turbine. 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 RR Trent 60 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 for the ESPFM Project. 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 967 lbs of CO_2 per net megawatt hours at 45% load, or 877 lbs of CO_2 per net megawatt hours at 100% load. Because BACT must apply at all loads the applicable BACT limit is set at 50% load, to be 967 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 763,684 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 RR Trent 60 simple cycle generating system is expected to generate 1,503 lbs of CO2 per net megawatt hours at 55% load, or 1,114 lbs of CO2 per net megawatt hours at 100% load. Because BACT must apply at all loads the applicable BACT limit is set at 55% load, to be 1,503 lb/$_{net}$MWh. The equipment will also be subject to the CO2 emission limit of 140,998 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. In addition, no offsets are required for CO because this pollutant is in attainment in the South Coast Air Basin.

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 El Segundo Power Redevelopment (ESPR) Project has two Siemens-Westinghouse combined cycle gas turbines that were permitted at 2.0 ppmv in 2010. 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 Walnut Creek Energy Park has 5 GE LMS100 simple cycle gas turbines that were permitted at 2.5 ppmv in 2011. The ESPFM Project 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 98th 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 Los Angeles International Airport Station are used in the modeling analysis. At this station, the 1-hour average background concentration is 129.7 $\mu g/m^3$ based on the 3-year average 98th percentile, and the highest annual average background concentration is 24.5 $\mu g/m^3$. 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, El Segundo Power, LLC elected to model the impact from the entire new equipment as a group. The equipment group, which include the three turbines and the auxiliary boiler, 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 auxiliary boiler operating 8,760 hours per year. Table 14 provides a summary of the modeling results.

Table 7 – 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	129.7	20.9	150.6	188	No
Annual	24.5	0.6	25.1	56	No

a – Background concentration was measured at Los Angeles International Airport Meteorological Station

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. The total NOx RTC requirements of the repower project for the 1st year of operation is 183,989 lbs. This requirement is based on the emissions from the commissioning, and based on the annual operating schedule provided by El Segundo Power, LLC. After the 1st year the project will require 144,736 lbs of NOx RTC per year. It is lower than the 1st year requirement since the emissions from the commissioning are not included. 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

El Segundo Power, LLC 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 AFC. 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 ESPFM Project. Thus, the above three requirements have been met for the ESPFM Project.

Rule 2012 – Monitoring Recording and Record Keeping for RECLAIM

El Segundo Power, LLC 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.

Regulation XXX – Title V Operating Permit

El Segundo Power, LLC 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.

<u>40 CFR 60 Subpart D – Standards of Performance for Fossil Fuel Fired Steam Generators</u>
This regulation applies to fossil fuel fired steam generating units which are rated at greater than 250 MMBTU/hr (73 MW) and which commenced construction after August 17, 1971. The auxiliary boiler is a new construction however it is rated at 36 MMBTU/hr. Therefore, this regulation does not apply to the auxiliary boiler.

<u>40 CFR 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units</u>
This regulation applies to electric utility steam generating units which are rated at greater than 250 MMBTU/hr (73 MW) and which commenced construction after September 18, 1978. The auxiliary boiler is a new construction however it is rated at 36 MMBTU/hr and does not generate electricity. Therefore, this regulation does not apply to the auxiliary boiler.

<u>40 CFR 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units</u>

This subpart applies to any industrial, commercial or institutional steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBTU/hr)). The auxiliary boiler is a new construction and is rated at 36 MMBTU/hr. Therefore, this regulation does not apply to the auxiliary boiler.

<u>RECOMMENDATION</u>

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) CEC's approval of the proposed AFC. 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 gas turbines #9, 11, and 12 or the auxiliary boiler unless it demonstrates compliance with this limit.

The operator shall calculate the emission limits(s) by using the calendar monthly fuel use data and the following emission factors: PM2.5: 4.09 lb/mmscf for GE 7FA combined cycle gas turbine; 9.98 lb/mmscf for Trent 60 simple cycle gas turbines; 8.82 lb/mmscf for auxiliary boiler.

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

[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 #4 (Device D13) describing in detail the steps and schedule that will be taken to render Boiler #4 permanently in operable. The retirement plan shall be submitted to SCAQMD within 60 days after the permits to construct for Gas Turbine Units 9, 11, and 12 are issued.

The retirement plan must be approved in writing by SCAQMD. El Segundo Power, LLC shall not commence any construction of the ESPFM Project including Gas Turbine Units 9,11, and 12, Steam Turbine Unit 10, SCR/CO Catalysts for Gas Turbines 9, 11, and 12, and the Auxiliary Boiler before the retirement plan is approved in writing by SCAQMD. If SCAQMD notified El Segundo Power, LLC that the plan is not approvable, El Segundo Power, LLC shall submit a revised plan addressing SCAQMD's concerns within 30 days.

El Segundo Power, LLC shall provide SCAQMD by December 31, 2015 with a notarized statement that Boiler #4 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.

El Segundo Power, LLC shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shut down of Boiler #4, or advise SCAQMD as soon as practicable should El Segundo Power, LLC undertake permanent shutdown prior to December 31, 2015.

El Segundo Power, LLC shall cease operation of Boiler #4 within 90 calendar days for the first fire of Gas Turbine Unit 9 (Device D90), Unit 11 (Device D100) , or Unit 12 (Device D106), whichever occurs first.

[Rule 1304(a) – Modeling and Offsets]

Device Conditions of the New Equipment

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

CONTAMINANT	EMISSIONS LIMIT
CO	39,191 LBS IN ANY 1 CALENDAR MONTH
VOC	7,546 LBS IN ANY 1 CALENDAR MONTH
PM10	8,222 LBS IN ANY 1 CALENDAR MONTH
SOx	945 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: 2.92 lbs/mmscf, PM10: 4.51 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 SCAQMD 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: 22.52 lbs/mmscf, normal operation: 13.86 lbs/mmscf.

[Rule 1303, Rule 1703 – PSD]

A63.4 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	10,663 LBS IN ANY 1 CALENDAR MONTH
VOC	1,203 LBS IN ANY 1 CALENDAR MONTH
PM10	2,200 LBS IN ANY 1 CALENDAR MONTH
SOx	130 LBS IN ANY 1 CALENDAR MONTH

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

The operator shall calculate the emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 2.66 lbs/mmscf, PM10: 9.98 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 SCAQMD 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: 258.44 lbs/mmscf, normal operation: 9.30 lbs/mmscf.

[Rule 1303, Rule 1703 – PSD]

A99.12 The 30.88 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[Rule 2012]

A99.13 The 9.42 lbs/mmscf NOx emission limit(s) shall only apply during the interim period after commissioning to report RECLAIM emissions.

[Rule 2012]

A99.14 The 96.58 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[Rule 2012]

A99.15 The 16.16 lbs/mmscf NOx emission limit(s) shall only apply during the interim period after commissioning to report RECLAIM emissions.

[Rule 2012]

A195.12 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, fast start-ups, traditional startups, and shutdown periods. The commissioning period shall not exceed 800 hours. A fast start-up shall not exceed 30 minutes. A Traditional start-up shall not exceed 60 minutes. Shutdown time shall not exceed 30 minutes. The turbine shall be limited to a maximum of 150 fast start-ups per year, and a maximum of 50 traditional start-ups per year. Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[Rule 2005 – BACT, Rule XVII – PSD]

A195.13 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, fast start-ups, traditional start-ups, and shutdown periods. The commissioning period shall not exceed 800 hours. A fast start-up shall not exceed 30 minutes. A Traditional start-up shall not exceed 60 minutes. Shutdown time shall not exceed 30 minutes. The turbine shall be limited to a maximum of 150 fast start-ups per year, and a maximum of 50 traditional start-ups per year. Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[Rule XVII – PSD]

A195.14 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, fast start-ups, traditional start-ups, and shutdown periods. The commissioning period shall not exceed 800 hours. A fast start-up shall not exceed 30 minutes. A Traditional start-up shall not exceed 60 minutes. Shutdown time shall not exceed 30 minutes. The turbine shall be limited to a maximum of 150 fast start-ups per year, and a maximum of 50 traditional start-ups per year. Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[Rule 1303 – BACT]

A195.15 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. The commissioning period shall not exceed 206 hours. Start-up shall not exceed 30 minutes. Shutdown time shall not exceed 20 minutes. The turbine shall be limited to a maximum of 480 start-ups per year. Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[Rule 2005 – BACT, Rule XVII – PSD]

A195.16 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. This limit shall not apply to turbine commissioning, startup and shutdown periods. The commissioning period shall not exceed 206 hours. Start-up shall not exceed 30 minutes. Shutdown time shall not exceed 20 minutes. The turbine shall be limited to a maximum of 480 start-ups per year. Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[Rule XVII – PSD]

A195.17 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. This limit shall not apply to turbine commissioning, startup and shutdown periods. The commissioning period shall not exceed 206 hours. Start-up shall not exceed 30 minutes. Shutdown time shall not exceed 20 minutes. The turbine shall be limited to a maximum of 480 start-ups per year. Written records of commissioning, fast-start-ups, traditional start-ups, and shutdowns shall be maintained and made available upon request from the Executive Officer.

[Rule 1303 – BACT]

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]

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

Compounds	Grain per 100 scf
Sulfur compounds calculated as H2S greater than	0.25

This concentration limit is an annual average based on monthly samples of natural gas composition or gas supplier composition. The gaseous fuel sample shall be tested using District Method 307-91 for total sulfur calculated as H2S.

[Rule 1303(b)(2)-Offset]

C1.7 The operator shall limit the number of startups to no more than 62 in any one calendar month.

The number of fast start-ups shall not exceed 47 per month. The number of traditional start-ups shall not exceed 15 per calendar month.

The number of fast start-ups shall not exceed 1 per day. The number of traditional start-ups shall not exceed 1 per day.

The NOx emissions during a fast start-up shall not exceed 36 lbs. NOx emissions during a traditional start-up shall not exceed 62 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]

C1.8 The operator shall limit the number of startups to less than 60 in any one calendar month.

The number of startups shall not exceed 4 per day.

The NOx emissions from a startup shall not exceed 28 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]

C.1.9 The operator shall limit the natural gas usage to no more than 0.82 MMSCF per day.

[Rule 1303(a)(1) – BACT, Rule 2005]

D12.14 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.

The ammonia injection rate shall not exceed 135 lb/hr

[Rule 2005– BACT, Rule 1703- PSD]

D12.15 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 300°F and 650°F.

[Rule 2005– BACT, Rule 1703- PSD]

D12.16 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 drop across the catalyst shall remain between 1 inch of water column and 4 inches of water column.

[Rule 2005– BACT, Rule 1703- PSD]

D12.17 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.

The ammonia injection rate shall not exceed 47 lb/hr

[Rule 2005– BACT, Rule 1703- PSD]

D12.18 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 600°F and 1,125°F.

[Rule 2005– BACT, Rule 1703- PSD]

D12.19 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 drop across the catalyst shall remain between 1 inch of water column and 12 inches of water column.

[Rule 2005– BACT, Rule 1703- PSD]

D29.10 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 and PM2.5 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]

D29.11 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 SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when 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]

D29.12 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 SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

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

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

[Rule 1303 – BACT]

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

D29.13 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
PM10 emissions	Approved District Method	District	Outlet of the SCR

| | Approved |
| | Avg. Time |

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.

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]

D82.6 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]

D82.7 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 SCAQMD 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 SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).

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

E179.7 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. D12.14

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

E179.8 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. D12.15
Condition no. D12.16

[Rule 1303 – BACT, Rule 2005– BACT]

E179.9 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. D12.17

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

E179.10 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. D12.18
Condition no. D12.19

[Rule 1303 – BACT, Rule 2005– BACT]

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 California Energy Commission decision for the 00-AFC-14C project.

[CEQA]

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

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

The operator shall provide the SCAQMD with written notification of the initial startup date.

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

[Device subject to this condition: D96]

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 878,679 tons per year. The GHG emissions shall not exceed 967 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]

E193.7 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]

E193.8 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 140,998 tons per year. The GHG emissions shall not exceed 1,503 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]

I297.3 This equipment shall not be operated unless the facility holds 148,226 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. If the initial 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]

I297.4 This equipment shall not be operated unless the facility holds 46,675 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. If the initial 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]

I297.5 This equipment shall not be operated unless the facility holds 46,675 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. If the initial 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]

I297.6 This equipment shall not be operated unless the facility holds 521 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. If the initial 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]

K40.5 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]

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

Natural gas fuel use during the commissioning period

[Rule 2012]

APPENDIX A – CCGS CRITERIA POLLUTANT EMISSIONS

1. EMISSIONS FROM START-UP

The start-up process is defined when the gas turbine starts and when it reaches the designated operation load and achieves compliance with the BACT emission limits. During this process the SCR and the oxidation catalyst are not fully operational until their temperatures reach the operating temperature windows. Two types of start-ups have been identified for the GE 7FA Combined Cycle Gas Turbine.

Fast Start®

The Fast Start technology incorporates an auxiliary boiler to keep the CCGS in a state of readiness and to provide a source of steam to reduce the start-up time of the CCGS. Fast-Start duration is 30 minutes. NOx, CO, and VOC emissions during Fast Start are provided by GE. GE provided the following parameters and emissions rates of a Fast Start process

Fast Start duration: 30 minutes
Heat input: 728 MMBtu in LHV
LHV: 929.4 Btu/SCF
Fuel usage: 0.784 MMSCF

Table A-1 Fast Start Emissions

Event	Time (min)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)[1]	SOx (lbs)[2]
Fast Start Emissions	30	36.0	153.0	14.0	4.75	0.47

[1] PM10 = 9.5 lb/hr provided by GE. PM10 = 9.5*30/60 = 4.75 lbs
[2] SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 0.784 mmscf

Traditional Start

NOx, CO, and VOC emissions during a Traditional Start-up are provided by GE.
Traditional Start-up duration is 60 minutes. GE provided the following parameters and emissions rates of a Fast Start process:

Traditional Start duration: 60 minutes
Heat input: 1,563 MMBTU in LHV
LHV: 929.4 BTU/SCF
Fuel usage: 1.682 MMSCF

Table A-2 Traditional Start-up Emissions

	Time (min)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)[3]	SOx (lbs)[4]
Traditional Start Emissions	60	62.3	291.0	23.3	9.5	1.009

[3] PM10 = 9.5 lb/hr provided by GE
[4] SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 1.682 mmscf

2. EMISSIONS FROM SHUTDOWN

A shutdown is the process of bringing down the load of the gas turbine to zero. NOx, CO, and VOC emissions during a shutdown are provided by GE. PM10 and SOx emissions are not affected during a shutdown and are assumed to be equal to normal operations. Shutdown duration is 30 minutes. GE provided the following parameters and emissions rates of a Shutdown process

Shutdown duration: 30 minutes
Heat input: 765 MMBTU in LHV
LHV: 929.4 BTU/SCF
Fuel usage: 0.823 MMSCF

Table A-3 Shutdown Emissions

Event	Time (min)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)[5]	SOx (lbs)[6]
Shutdown Emissions	30	28.5	316.5	31.5	4.75	0.49

[5] PM10 = 9.5 lb/hr provided by GE
[6] SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 0.823 mmscf

3. EMISSIONS FROM BASE LOAD OPERATION

Base load operation is when the GE 7FA reaches its generating capacity and when the emissions are subject to BACT limits. The BACT 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 = 9.5 lbs/hr
SOx = 0.6 lbs/MMSCF

The applicant included performance runs and calculated emissions from base load operation at three ambient temperatures, 41°F, 78°F, and 90°F. These temperatures represent the coldest, average, and hottest monthly average ambient temperatures at the facility location. The results indicate that the highest amount of emissions occur when operating at cold peak scenario with the duct burner in operation and an ambient temperature of 41°F. Thus, the results of 41°F are selected for potential to emit (PTE) determinations.

At 41°F the GE 7FA combustion gas turbine has the following fuel parameters:

Heat Input:	1,955 MMBTU/hr, LHV
	2,168 MMBTU/hr, HHV
Fuel Flow:	2.105 MMscf/hr
LHV:	929 BTU/scf
HHV:	1,030 BTU/scf
Exhaust:	1,236,686 ACFM
Water Content:	9.06%
Oxygen Content, dry:	12.54%
Exhaust Temperature:	219°F, or 377°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.

1,236,686 * 288 / 377 = 944,736 SCFM, wet
944,736 * (1-9.06%) = 859,143 SCFM, dry
859,143 * (20.9%- 12.54%)/(20.9%-15%) = 1,217,362 DSCFM @ 15% O_2
1,217,362 * 60 = 73.04 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-mol
Mass emissions in lb/hr = lb-mol/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	N/A	N/A	5.0
Molecular Weight	46	28	16	N/A	N/A	17

Mass in lb-mol/hr	0.385	0.385	0.385	N/A	N/A	0.962
Mass in lb/hr	17.71	10.78	6.16	9.5	1.26	16.35
Mass in lb/mmscf	8.41	5.12	2.92	4.51	0.6	7.77

4. EMISSIONS FROM COMMISSIONING

Process Description

The GE 7FA 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. El Segundo Power, LLC provided a 71 day multi-step commissioning process for the 7FA gas turbine. GE estimates that it will take 800 hours to accomplish the commissioning.

The following table describes the commissioning process.

Table A-5 Commissioning Schedule

Activity	Duration (hr)	Load (MW)	Fuel Usage MMSCF	SCR (Y/N)
GT Testing (FSNL-50%)	16	105	15.33	N
Steam Blows	96	105	126.18	N
Establish Steam Purity	160	210	328.30	N
Establish Vacuum	32	105	42.06	N
By-Pass Valve Tuning	108	105-210	164.66	N
SCR Ammonia System Commissioning	16	210	34.80	Y
STG Load & Trip Test	44	105-210	73.22	Y
Drift Test	144	210	310.36	Y
Emission Test/RATA	32	210	70.64	Y
Performance/Reliability Test	80	210	176.35	Y
SCE 72 Hour Test	72	210	151.60	Y

Emission Calculations

Emissions of the commissioning process are provided by GE. The following table shows detailed emissions of each process.

Table A-6 GE 7FA Commissioning Emissions

Activity	Duration (hr)	Fuel Usage MMSCF	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)
GT Testing (FSNL-50%)	16	15.33	801.67	327.62	56.60	153.95	32.85
Steam Blows	96	126.18	6,237.96	1,976.39	392.94	920.89	257.84
Establish Steam Purity	160	328.30	16,929.00	5,138.80	1,205.80	1,542.50	703.50
Establish Vacuum	32	42.06	2,162.54	469.20	136.66	305.74	90.12
By-Pass Valve Tuning	108	164.66	7,707.83	3,058.37	645.89	1,041.66	352.86
SCR Ammonia System Commissioning	16	34.80	764.58	1,435.82	207.58	161.22	74.60
STG Load & Trip Test	44	73.22	1,594.69	3,076.01	450.98	436.20	156.97
Drift Test	144	310.36	5,566.55	8,957.17	1,534.98	1,485.68	665.19
Emission Test/RATA	32	70.64	848.75	2,752.28	418.47	340.10	151.43
Performance/Reliability Test	80	176.35	2,062.85	4,465.04	846.61	884.11	377.90
SCE 72 Hour Test	72	151.60	1,450.08	1,978.96	537.39	738.92	324.70
TOTALS	800	1,493.50	46,126	33,636	6,433	8,011	3,188

The average emission factors during the commissioning are calculated in the next table. Total fuel consumption is 1,493.50 MMSCF

Table A-7 Emission Factors – Commissioning

	NOx	CO	VOC
Emissions during Commissioning (lb)	46,126	33,636	6,433
Fuel Consumption, MMSCF	1,493.50	1,493.50	1,493.50
Emission Factor (lb/MMSCF)	30.88	22.52	4.31

In accordance with RECLAIM rules the NOx emission factor of 30.88 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 Fast Start lasting 30 minutes (plus 30 minutes at normal emission rates), one

Traditional Start lasting 60 minutes at, two shutdowns each lasting 60 minutes, and continued operation at 100% load for the remaining 20 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 Fast Start (lbs)	36.00	153.0	14.10	4.75	0.47
1 Traditional Start (lbs)	62.30	291.00	23.30	9.50	1.009
2 Shutdowns (lbs)	57.00	633.00	63.0	9.50	0.98
Emission Factor – Normal Operation (lb/hr)	17.71	10.78	6.16	9.50	1.26
Normal operation emissions for 21.5 hours (lbs)	380.77	231.77	132.44	204.25	25.20
Daily total (lbs)	536.07	1,308.77	232.84	228.00	28.32

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

NH3 = 24 * 16.35 = 392.40 lbs/day

6. MONTHLY EMISSIONS

The following hypothetical monthly operating schedule is proposed:

Monthly schedule: 730 hours (30.42 days), base load operation that includes 47 Fast Starts, 15 Traditional Start-ups, and 62 shutdowns.

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

(30.42*24*60 – 47*30 – 15*60 – 62*30)/60 = 660.58 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
Fast Start – 47 events (lbs)	1,692	7,191	663	223	22	0

Traditional Start-ups – 15 events (lbs)	935	4,365	350	143	15	0
Shutdowns – 62 events (lbs)	1,767	19,623	1,953	295	30	0
Base load operation (lbs)	11,699	7,121	4,069	6,276	764	9,908
Monthly total (lbs/month)	16,093	38,300	7,035	6,937	831	11,934

Total fuel consumption in a month is:

47*0.784 + 15*1.682 + 62*0.823 + 660.58*2.105 = 1,503.62 MMSCF

Equivalent emission factors are:

Table A-10 Average Emission Factors – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Average Emission Factor (lbs/mmscf)	10.70	25.47	4.67	4.61	0.60	8.59

The First Month

The first month of operation includes only commissioning. It is assumed that the operation comprises an entire month (744 hours) of commissioning and no baseload operation. The total commissioning period is to last for 800 hours. Therefore, the emissions from the first month will be 744/800 of the total amounts in Table A-6 above.

Table A-11 1st Month Total Emissions

	NOx	CO	VOC	PM10	SOx
Commissioning – 744 hours (lbs)	42,897	31,282	5,983	7,450	2,965

7. YEARLY EMISSIONS

The following annual operating schedule is proposed:

Annual schedule: 5,456 total hours that includes 150 Fast Starts, 50 Traditional startups, and 200 shutdowns.

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

5,456 – 150*30/60 – 50*60/60 – 200*30/60 = 5,231 hours

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

Table A-12 Annual Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx	NH3
Fast Start – 150 events (lbs)	5,400	22,950	2,100	713	71	N/A
Traditional startups – 50 events (lbs)	3,115	14,550	1,165	475	50	N/A
Shutdowns – 200 events (lbs)	5,700	63,300	6,300	950	98	N/A
Base load operation – 5,231 hours (lbs/yr)	92,641	56,390	32,223	49,695	6,371	82,666
Total (lbs/yr)	106,856	157,190	41,788	51,833	6,590	82,666
Total (tons/yr)	53.43	78.60	20.89	25.92	3.295	41.33

Annual fuel usage of the above operation schedule:

150*0.784 + 50*1.682 + 200*0.823 + 5,231*2.105 = 11,337.56 MMSCF (100% load)
150*0.784 + 50*1.682 + 200*0.823 + 5,231*1.281 = 7,065.03 MMSCF (45% load)

First Year Operation

The first year includes the commissioning process. It includes 800 hours of commissioning and 5,456 – 800 = 4,656 hours of normal operations. Therefore, the emissions during normal operation for the first year will be 4,656/5,456 of the amounts in Table A-13 above and are shown in Table A-14 below:

Table A-13 First Year Emissions

	NOx	CO	VOC	PM10	SOx
Commissioning – 800 hours (lbs)	46,126	33,636	6,433	8,011	3,188
Normal Operations, 4,656 hours (lbs)	91,188	134,142	35,661	44,233	5,624
Total (lbs)	137,314	167,778	42,094	52,244	8,812

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 = 11,337.56 * 4,656/5,456 = 9,675.16 MMSCF

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

NOx = 91,188/9,675.16 = 9.42 lbs/MMSCF
CO = 134,142/9.675.16 = 13.86 lb/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 of Tables A-8 and A-10, as shown in Table A-15 below:

Table A-14 – CCGS PTE of Criteria Pollutants

	NOx	CO	VOC	PM10	SOx
Highest Monthly Total (lbs/month)	42,897	38,300	7,035	7,450	2,965
30-Day Average (lbs/day)	1,429.90	1,276.67	234.50	248.33	98.83

The RECLAIM Trading Credits (RTC) requirement is calculated based on annual NOx emissions. As determined in Tables A-13 and A-14 the first year requirement is 137,314 lbs (CTG) + 10,912 lbs (DB) = 148,226 lbs and the years after the first year is 106,856 lbs (CTG) + 10,912 lbs (DB) = 117,768 lbs.

APPENDIX B – SCGS CRITERIA POLLUTANTS EMISSIONS

1. EMISSIONS FROM START-UPS

The startup process is defined as the time between initial start-up of a Trent 60 gas turbine 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. El Segundo Power, LLC has specified that the startup process for each of the Trent 60 Simple Cycle Gas Turbines will take 30 minutes. GE provided the following parameters and emissions rates of a startup of each Trent 60 gas turbine.

Startup duration:	30 minutes
Heat input:	181 MMBTU (LHV)
LHV:	929.4 BTU/scf
Fuel usage:	0.194 MMSCF

Table B-1 Startup Emissions – Each Trent 60 Gas Turbine

Event	Time (min)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)[7]	SOx (lbs)[8]
Start-up	30	28.0	87.5	6.7	2.5	0.116

[7] PM10 = 5.0 lb/hr provided by GE. PM10 = 5.0*30/60 = 2.5 lbs

[8] SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 0.194 mmscf.

2. EMISSIONS FROM SHUTDOWN

The shutdown is the process of reducing the gas turbine load to zero. It typically takes 20 minutes to conduct a shutdown process for the RR Trent 60 gas turbine. GE provided the following parameters and emission factors.

Shutdown duration:	20 minutes
Heat input:	91 MMBTU (LHV)
LHV:	929.4 BTU/scf
Fuel usage:	0.098 MMSCF

Table B-2 Shutdown Emissions – Each Trent 60 Gas Turbine

Event	Time (min)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)[9]	SOx (lbs)[10]
Shutdown	20	7.1	60.0	4.7	1.67	0.059

[9] PM10 = 5.0 lb/hr provided by GE. PM10 = 5.0*20/60 = 1.67 lbs

[10] SOx emissions are calculated with the emission factor of 0.6 lb/mmscf and fuel usage of 0.098 mmscf.

3. EMISSIONS FROM BASE LOAD OPERATION

Base load operation is when the gas turbine 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 = 5.0 lbs/hr
SOx = 0.6 lbs/MMSCF

The applicant calculated emissions from normal operation at three ambient temperatures, 90°F, 78°F, and 41°F. These temperatures represent the hottest, average, and coldest monthly average ambient temperatures at the facility location. The results indicate that the highest amount of emissions occur when operating at the mild base (cooler) scenario an ambient temperature of 78°F. Thus, the results of 78°F at mild base (cooler) conditions are selected for potential to emit (PTE) determinations.

At 78°F the RR Trent 60 Gas Turbine has the following fuel parameters:

Heat Input:	516 MMBTU/hr
Fuel Flow:	0.501 MMSCF/hr
Exhaust:	701,728 ACFM
Exhaust Water Content:	8.41%
Exhaust Oxygen Content:	14.99%
Exhaust Temperature:	809°F or 705°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.

701,728 * 288 / 705 = 286,663 SCFM, wet
286,663 * (1-8.41%) = 262,555 SCFM, dry
262,555 * (20.9% -14.99%)/(20.9% -15%) = 263,000 DSCFM @ 15% O_2
263,000 * 60 = 15.78 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 B-3 Base Load Operation Emissions – Each Turbine

	NOx	CO	VOC	PM	SOx	NH3
Concentration in ppmv	2.5	4.0	2.0	N/A	N/A	5.0
Molecular Weight	46	28	16	N/A	N/A	17
Mass in lb-moles/hr	0.104	0.166	0.083	N/A	N/A	0.208
Mass in lb/hr	4.78	4.65	1.33	5.0	0.30	3.53
Mass in lb/mmscf	9.54	9.30	2.66	9.98	0.60	7.05

4. EMISSIONS FROM COMMISSIONING

Process Description

The gas turbines must first be commissioned to the desired performance before they begin regular service. Commissioning is a dedicated process that is generally prescribed by the turbine manufacturer. The manufacturer-recommended commissioning schedule will be an 8-step process that will take a total of 206 hours to accomplish for each of the Trent 60 gas turbines. The following table describes the commissioning process for the Trent 60 gas turbines.

Table B-4 Trent 60 Turbine Commissioning Schedule

Commissioning Activity	Process	Duration, (hours)	GT Load, MW	SCR (Y/N)
First Fire and Idle Running	Step #1	18	FSNL	N
Synchronization of the Unit	Step #2	16	FSNL	N
Tuning – Baseload Running	Step #3	64	45.8	N

Commissioning of Inlet Fogging and ISI	Step #4	24	22.9	N
SCR Tuning	Step #5	24	45.8	Y
RATA Test	Step #6	12	45.8	Y
Performance Test	Step #7	24	45.8	Y
24-hr Reliability Test	Step #8	24	45.8	Y
TOTAL		206		

Emissions Calculations

Emissions of the commissioning process are provided by RR. SOx emissions are calculated using 0.6 lb/MMSCF. The following table shows detailed emissions of each process.

Table B-5 Natural Gas Commissioning Summary

Process	Duration (hours)	Heat Input (MMBTU) LHV	Fuel (MMSCF)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)
Step #1	18	12,158	13.1	1,141	6,234	870	199	27
Step #2	16	9,442	10.2	705	3,174	237	121	10
Step #3	64	34,211	36.8	4,941	13,270	848	684	38
Step #4	24	12,223	13.1	806	3,855	253	131	13
Step #5	24	9,959	10.7	2,405	658	73	266	11
Step #6	12	4,818	5.2	92	172	21	67	5
Step #7	24	9,636	10.4	184	343	42	134	11
Step #8	24	9,474	10.2	148	181	25	127	10
Total	206		109.7	10,421	27,886	2,370	1,729	126

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

Table B-6 Emission Factors – Commissioning

	NOx	CO
Emissions during Commissioning, lb	10,421	27,886
Fuel Consumption, MMSCF	107.9	107.9
Emission Factor (lb/MMSCF)	96.58	258.44

In accordance with RECLAIM rules the NOx emission factor of 96.58 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 4 startups lasting 4*30 minutes (2.00 hours), four shutdowns lasting 4*20 minutes (1.33 hours), and continued operation at 100% load for the remaining 20.67 hours of a day. The emissions are calculated and shown in the next table. PM10 and SOx emissions are based on 5 lb/hr and 0.3 lb/hr, respectively. Table B-7 below shows the maximum daily emissions from each Trent 60 simple cycle gas turbine.

Table B-7 Maximum Daily Emissions – Normal Operation, Per Turbine

	NOx	CO	VOC	PM10	SOx
4 Startup emissions (lbs)	112.0	350.0	26.8	10.0	0.46
4 Shutdown emissions (lbs)	28.4	240.0	18.8	6.68	0.24
Emission factor – base load operation (lb/hr)	4.78	4.65	1.33	5.0	0.30
Emissions (lbs)– base load operation for 20.67 hours	98.80	96.12	27.49	103.35	6.20
Daily total (lbs/day)	239.2	686.12	73.09	120.0	6.9

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 * 3.53 = 84.72 lbs/day

6. MONTHLY EMISSIONS

Once the Trent 60 gas turbines start commercial operation El Segundo Power, LLC 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 a maximum of 60 start-ups and 60 shutdowns per month.

The following monthly operating schedule for each Trent 60 gas turbine is proposed:

Monthly schedule: 440 hours (18.33 days), normal operation that includes 60 Start ups, and 60 shutdowns.

Excluding the startups and shutdowns the base load operation duration calculated below. The monthly emissions from each Trent 60 gas turbine are calculated and summarized in the next table.

Base Load Duration = (18.33*24*60 – 60*30 – 60*20)/60 = 389.92 hours

Table B-8 Monthly Total Emissions – Normal Operation, per Turbine

	NOx	CO	VOC	PM10	SOx	NH3
Startups – 60 events (lbs)	1,680	5,250	402	150	6.96	N/A
Shutdowns – 60 events (lbs)	426	3,600	282	100	3.54	N/A
Base load operation – 389.92 hours (lbs)	1,863.82	1,813.13	518.59	1,949.60	119.68	1,376.42
Monthly total (lbs/month)	3,969.82	10,663.12	1,202.60	2,199.60	130.18	1,376.42

Monthly Fuel Consumption (per turbine):

Q = 60*0.194 + 60*098 + 389.92*0.501 = 212.87 MMSCF/month

The equivalent emission factors are:

Table B-9 Emission Factors – Normal Operation

	NOx	CO	VOC
Average Emission Factor (lbs/mmscf)	18.65	50.09	5.65

The First Month

The first month operation includes commissioning. It is assumed that the month includes 206 hours of commissioning and 234 hours of normal operation. The load factor is assumed to be 100%. The emissions from normal operation is assumed to be 234/440 of the monthly totals in Table B-8. The next table calculates the monthly total emissions.

Table B-10 Monthly Emissions– First Month, per Turbine

	NOx	CO	VOC	PM10	SOx
Commissioning – 206 hours (lbs)	10,421	27,886	2,370	1,729	126
Normal Operation, – 234 hours (lbs)	2,111.22	5,670.84	639.56	1,169.79	69.23
Monthly total (lbs)	12,532.22	33,556.84	3,009.56	2,898.79	195.23

Fuel usage for the first month:

Q = 62.49 + 13.29*(4*0.194+4*0.098+20.67*0.501) = 215.64 MMSCF

7. YEARLY EMISSIONS

The following annual operating schedule is proposed:

Annual schedule: 4,800 total hours of normal operation that includes 480 startups and 480 shutdowns.

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

4,800 – 480*30/60 – 480*20/60= 4,400 hours

Emissions generated from this operating schedule are calculated and presented in the next table.

Table B-11 Annual Emissions – Normal Operation, per Turbine

	NOx	CO	VOC	PM10	SOx	NH3
Startups – 480 events (lbs)	13,440	42,000	3,216	1,200	56	N/A
Shutdowns – 480 events (lbs)	3,408	28,800	2,256	802	28	N/A
Base load operation 4,400 hours (lbs)	21,032	20,460	5,852	22,000	1,320	15,532
Total (lbs)	37,880	91,260	11,324	24,002	1,404	15,532

Total (tons/year)	18.94	45.63	5.66	12.00	0.70	7.76

Annual Fuel Consumption:

Q = 480*0.194 + 480*0.098 + 4,400*0.501 = 2,344.56 MMSCF

First year operation

The first year includes the commissioning process. It includes 206 hours of commissioning and 4,594 hours of normal operation. The emissions from normal operation is assumed to be 4,594/4,800 of the annual emissions calculated in Table B-11.

Table B-12 First Year Emissions – per Turbine

	NOx	CO	VOC	PM10	SOx
Commissioning – 206 hours (lbs)	10,421	27,886	2,370	1,729	126
Normal Operation – 4,594 hours (lbs)	36,254.31	87,335.82	10,837.07	22,969.91	1,343.63
Total (lbs)	46,675.31	115,221.82	13,207.07	24,698.91	1,469.63

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 = 2,344.56 * 4594/4800 = 2,243.94 MMSCF

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

NOx = 36,254.31/2,243.94 = 16.16 lbs/MMSCF
CO = 87,335.82/2,243.94 = 38.92 lb/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.

Table B-13 SCGS PTE – Each Turbine

	NOx	CO	VOC	PM10	SOx
Highest Monthly Total (lbs/month)	12,532.22	33,556.84	3,009.56	2,898.79	195.23
30-Day Average (lbs/day)	417.75	1,118.56	100.31	96.63	6.51

The RECLAIM Trading Credits (RTC) requirement is calculated based on annual NOx emissions. As determined in Tables B-11 and B-12 the first year requirement of each of the SCGS turbines is 46,675 lbs and the years after the first year is 37,880 lbs.

10. RR TRENT 60 NOx EMISSIONS – lb/net MWH

Electrical Output (per turbine) = 55 net MW
Average net Electricity Production = 50.61 MW

Event	Duration (hr)	Emissions (lb)	Turbine Net MW	Average Emissions lb/net MW-hr
Baseload	1.0	2.40	2.29	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	

	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	55.0	
	1.0	4.78	2.29	
TOTAL	24	111	50.61	0.091

NOx Emissions = (111 lb/24 hr)/50.61 MW = 0.091 lb/net MWH

APPENDIX C – DUCT BURNER AND AUXILIARY BOILER EMISSIONS

Duct Burner

The Duct Burner is assumed to be in simultaneous operation with the CCGS, and is located upstream of the CO catalyst and SCR systems. The emissions from the Duct Burner will therefore be controlled to BACT limits.

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

Particulate matter and SOx emissions are calculated using:

PM10 = 0.0066 lb/MMBTU
SOx = 0.6 lbs/MMSCF

The applicant calculated emissions from normal operation at three ambient temperatures, 90°F, 78°F, and 41°F. These temperatures represent the hottest, average, and coldest monthly average ambient temperatures at the facility location. The results indicate that the highest amount of emissions occur when operating at an ambient temperature of 41°F. Thus, the results of 41°F at scenario are selected for potential to emit (PTE) determinations.

At 41°F the Duct Burner has the following fuel parameters:

Heat Input: 268 MMBTU/hr
Fuel Flow: 0.260 MMSCF/hr

Assumptions:

Specific Molar Volume, SMV= 379.5 scf/lb-mole
F-Factor for Natural Gas, F_d = 8,710 dscf/MMBTU

Emissions (lb/MMBTU) = $(ppmvd/10^6)*MW*F_d*(1/SMV)*(20.9/5.9)$
Emissions (lb/hr) = 268 MMBTU/hr* lb/MMBTU

The next table shows the mass emission rates.

Table C-1 Duct Burner Emissions

	NOx	CO	VOC	PM	SOx
Concentration, ppmvd	2.0	2.0	2.0	N/A	N/A
Molecular Weight, MW	46	28	16	N/A	N/A
Mass in lb/MMBTU	0.00748	0.00455	0.00260	N/A	N/A
Mass in lb/hr	2.00	1.22	0.70	1.76	0.156
Mass in lb/month	1,460.00	890.60	511.00	1,284.80	113.80
Mass in lb/year	10,912.00	6,656.32	3,819.20	9,602.56	851.14
Mass in ton/year	5.45	3.33	1.91	4.80	0.426
30 Day Average, lb/day	48.67	29.68	17.03	42.83	3.79
Mass in lb/mmscf	7.69	4.69	2.69	6.76	0.60

Auxiliary Boiler

The Auxiliary Boiler will operate at 25% load except during periods when the CCGS starts-up for 20 minutes each day, when it will operate at 100% load. The applicant has assumed that the Auxiliary Boiler will operate for 24 hr/day, 7 days/week. The auxiliary boiler has the following concentration limits as provided by Cleaver Brooks:

NOx = 5 ppmvd at 3% O_2, dry
CO = 30 ppmvd at 3% O_2, dry

PM10, VOC, and SOx emissions are calculated using:

PM10 = 0.3 lb/hr
VOC = 0.1 lb/hr
SOx = 0.6 lbs/MMSCF

Heat Input: 36 MMBTU/hr
Fuel Flow: 0.034 MMSCF/hr
Molecular Weight, lb/lb-mole
Specific Molar Volume, SMV = 379.5 scf/lb-mole
F-Factor for Natural Gas, F_d = 8,710 dscf/MMBTU

Emissions (lb/MMBTU) = $(ppmvd/10^6)*MW*F_d*(1/SMV)*(20.9/17.9)$

The auxiliary boiler will operate at 100% load for 20 minutes (0.33 hours) and 25% load for the remainder of the day (23.67 hours). The mass emission rates in lb/hr below are provided by Cleaver Brooks. The Auxiliary Boiler emissions are shown in Table C-4 below:

NOx = 0.4 lb/hr * (0.33/24) + 0.4 lb/hr * (23.67/24)(0.25) = 0.104 lb/hr
CO = 1.3 lb/hr * (0.33/24) + 1.3 lb/hr * (23.67/24)(0.25) = 0.338 lb/hr
VOC = 0.1 lb/hr * (0.33/24) + 0.1 lb/hr * (23.67/24)(0.25) = 0.026 lb/hr
PM10 = 0.3 lb/hr * (0.33/24) + 0.3 lb/hr * (23.67/24)(0.25) = 0.078 lb/hr
SOx = 0.0204 lb/hr * (0.33/24) + 0.0204 lb/hr * (23.67/24)(0.25) = 0.0053 lb/hr

Table C-2 Auxiliary Boiler Emissions

	NOx	CO	VOC	PM	SOx[11]
Concentration, ppmvd	5	30	3.21	N/A	N/A
Molecular Weight, MW	46	28	16	N/A	N/A
Mass in lb/MMBTU	0.006	0.022	0.0014	N/A	N/A
Mass in lb/hr	0.059	0.338	0.026	0.078	0.0053
Mass in lb/month	44.21	251.47	19.34	58.03	3.94
Mass in lb/year	520.59	2,960.88	227.76	683.28	46.43
Mass in tons/yr	0.26	1.48	0.11	0.34	0.02
30 Day Average, lb/day	1.44	8.22	0.63	1.89	0.13

11 SOx = 0.6 lb/MMSCF*0.034 MMSCF/hr = 0.0204 lb/hr @ 100% load

APPENDIX D –TAC and HAP EMISSIONS

The equipment is 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 SCAQMD Rule 1401.

1. CCGS

HAP and TAC emissions are calculated under a variety of operating parameters. The following worst-case operating scenario includes simultaneous operation of the GE 7FA Gas Turbine and the Duct Burner, including start-ups and shutdowns, and results in the highest amount of HAP and TAC emissions. The TAC and HAP emissions are shown in the next two tables.

Annual hours of operation:	5,406 hours
Maximum Firing Rate:	2,436.1 MMBTU/hr (GE 7FA+DB)
Ambient temperature:	41°F
Load Factor:	100% base load
Fuel flow rate:	2.365 MMSCF/hr (GE 7FA+DB)
Annual total fuel usage:	12,785.19 MMSCF/year

Table D-1 TAC Emissions – CCGS

TAC Pollutants	Aix Toxic CAS Number	Emission Factor (lb/MMSCF)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
Ammonia	7664417	N/A	1.34E+01	44.50
1,3-Butadiene	106990	4.39E-04	1.04E-03	0.00
Acetaldehyde	75070	4.08E-02	9.65E-02	0.26
Acrolein	107028	6.53E-03	1.54E-02	0.04
Benzene	71432	1.22E-02	2.90E-02	0.08
Ethylbenzene	100414	3.26E-02	7.72E-02	0.21
Formaldehyde	50000	7.24E-01	1.71E+00	4.63
Propylene	115071	7.71E-01	1.82E+00	4.93
Propylene Oxide	75569	2.96E-02	7.00E-02	0.19
Toluene	108883	1.33E-01	3.14E-01	0.85
Xylenes	1330207	6.53E-02	1.54E-01	0.42
Benzo(a)anthracene	56556	2.26E-05	5.35E-05	0.00
Benzo(a)pyrene	50328	1.39E-05	3.29E-05	0.00
Benzo(b)fluoranthene	205992	1.13E-05	2.67E-05	0.00
Benzo(k)fluoranthene	207089	1.10E-05	2.60E-05	0.00
Chrysene	218019	2.52E-05	5.96E-05	0.00
Diebenz(a,h)anthracene	53703	2.35E-05	5.56E-05	0.00
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	5.56E-05	0.00
Naphthalene	91203	1.33E-03	3.14E-03	0.01
			Total TAC Emissions Per Year	56.12

Table D-2 HAP Emissions – CCGS

HAP Pollutants	Aix Toxic CAS Number	Emission Factor (lb/MMSCF)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
1,3-Butadiene	106990	4.39E-04	1.04E-03	0.00
Acetaldehyde	75070	4.08E-02	9.65E-02	0.26
Acrolein	107028	6.53E-03	1.54E-02	0.04
Benzene	71432	1.22E-02	2.90E-02	0.08
Ethylbenzene	100414	3.26E-02	7.72E-02	0.21
Formaldehyde	50000	7.24E-01	1.71E+00	4.63
Hexane	110543	2.59E-01	6.13E-01	1.66
Propylene Oxide	75569	2.96E-02	7.00E-02	0.19
Toluene	108883	1.33E-01	3.14E-01	0.85
Xylenes	1330207	6.53E-02	1.54E-01	0.42
Anthracene	120127	3.38E-05	8.00E-05	0.00
Benzo(a)anthracene	56556	2.26E-05	5.35E-05	0.00
Benzo(a)pyrene	50328	1.39E-05	3.29E-05	0.00
Benzo(b)fluoranthene	205992	1.13E-05	2.67E-05	0.00
Benzo(k)fluoranthene	207089	1.10E-05	2.60E-05	0.00
Chrysene	218019	2.52E-05	5.96E-05	0.00
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	5.56E-05	0.00
Naphthalene	91203	1.33E-03	3.14E-03	0.01
Diebenz(a,h)anthracene	53703	2.35E-05	5.56E-05	0.00
			Total HAP Emissions Per Year	8.35

2. <u>SCGS</u>

Tables D-3 and D-4 below represent the HAP and TAC emissions from a single Trent 60 Gas Turbine. 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:	4,800 hours
Maximum Firing Rate:	516 MMBTU/hr
Ambient temperature:	78°F
Load Factor:	100% base load
Fuel flow rate:	0.501MMSCF/hr
Annual total fuel usage:	2,404.80 MMSCF/year

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	N/A	1.99E-00	8.43
1,3-Butadiene	106990	4.39E-04	2.2E-04	0.00
Acetaldehyde	75070	4.08E-02	2.04E-02	0.05
Acrolein	107028	6.53E-03	3.27E-03	0.01
Benzene	71432	1.22E-02	6.13E-03	0.01
Ethylbenzene	100414	3.26E-02	1.64E-02	0.04
Formaldehyde	50000	7.24E-01	1.30E-01	0.31
Propylene	115071	7.71E-01	3.86E-01	0.93
Propylene Oxide	75569	2.96E-02	1.48E-02	0.04
Toluene	108883	1.33E-01	6.64E-02	0.16
Xylenes	1330207	6.53E-02	3.27E-02	0.08
Benzo(a)anthracene	56556	2.26E-05	1.13E-05	0.00
Benzo(a)pyrene	50328	1.39E-05	6.96E-06	0.00
Benzo(b)fluoranthene	205992	1.13E-05	5.66E-06	0.00
Benzo(k)fluoranthene	207089	1.10E-05	5.51E-06	0.00
Chrysene	218019	2.52E-05	1.26E-05	0.00
Diebenz(a,h)anthracene	53703	2.35E-05	1.18E-05	0.00
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	1.18E-05	0.00
Naphthalene	91203	1.33E-03	6.64E-04	0.00
Total TAC Emissions Per Year				10.06

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	4.39E-04	2.2E-04	0.00
Acetaldehyde	75070	4.08E-02	2.04E-02	0.05
Acrolein	107028	6.53E-03	3.27E-03	0.01
Benzene	71432	1.22E-02	6.13E-03	0.01
Ethylbenzene	100414	3.26E-02	1.64E-02	0.04
Formaldehyde	50000	7.24E-01	1.30E-01	0.87
Hexane	110543	2.59E-01	1.30E-01	0.31
Propylene Oxide	75569	2.96E-02	1.48E-02	0.04
Toluene	108883	1.33E-01	6.64E-02	0.16
Xylenes	1330207	6.53E-02	3.27E-02	0.08
Anthracene	120127	1.39E-05	2.2E-04	0.00
Benzo(a)anthracene	56556	4.39E-04	2.04E-02	0.00
Benzo(a)pyrene	50328	4.08E-02	3.27E-03	0.00
Benzo(b)fluoranthene	205992	1.13E-05	5.66E-06	0.00

Benzo(k)fluoranthene	207089	1.10E-05	5.51E-06	0.00
Chrysene	218019	2.52E-05	1.26E-05	0.00
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	1.18E-05	0.00
Naphthalene	91203	1.33E-03	6.64E-04	0.00
Diebenz(a,h)anthracene	53703	2.35E-05	1.18E-05	0.00
Total HAP Emissions Per Year				1.57

3. <u>AUXILIARY BOILER</u>

The TAC and HAP emissions are calculated based on the parameters listed below. The combined TAC and HAP emissions are calculated in Table D-5.

Annual hours of operation:	8,760 hours
Maximum Firing Rate:	36 MMBTU/hr
Fuel flow rate:	0.0349 MMSCF/hr
Annual total fuel usage:	306 MMSCF/year

Table D-5 TAC and HAP Emissions – Auxiliary Boiler

TAC/HAP Pollutants	Aix Toxic Case Number	Emission Factor (lb/MMSCF)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
Benzene	71432	5.80E-03	2.03E-04	0.00
Formaldehyde	50000	1.23E-02	4.30E-04	0.00
PAHs (including naphthalene)	107028	4.00E-04	1.40E-05	0.00
Naphthalene	91203	3.00E-04	1.05E-05	0.00
Acetaldehyde	75070	3.10E-03	1.08E-04	0.00
Acrolein	1070208	2.70E-03	9.44E-05	0.00
Propylene	115071	5.30E-01	1.85E-02	0.08
Hexane	110543	4.60E-03	1.61E-04	0.00
Toluene	108883	2.65E-02	9.26E-04	0.00
Xylenes	1330207	1.97E-02	6.89E-04	0.00
Ethyl Benzene	100414	6.90E-03	2.41E-04	0.00
Total HAP Emissions Per Year				0.08

4. <u>EXISTING CTG UNITS 5 & 7</u>

Tables D-6 below represents the estimated HAP emissions from existing combined cycle Gas Turbine Units 5 and 7. HAP emissions are calculated under a variety of operating parameters. The following operating scenario generates the highest amount of HAP emissions:

Annual hours of operation: 5,456 hours
Maximum Firing Rate: 2,096 MMBTU/hr
Ambient temperature: 78°F
Fuel flow rate: 2.0395 MMSCF/hr
Annual total fuel usage: 11,127.51 MMSCF/year

HAP Pollutants	Aix Toxic Case Number	Emission Factor (lb/MMSCF)	Emission Rate (lb/hr)	Annual Emissions (tons/year)
1,3-Butadiene	106990	4.39E-04	8.95E-04	0.002
Acetaldehyde	75070	4.08E-02	8.32E-02	0.227
Acrolein	107028	6.53E-03	1.33E-02	0.036
Benzene	71432	1.22E-02	2.48E-02	0.068
Ethylbenzene	100414	3.26E-02	6.64E-02	0.181
Formaldehyde	50000	7.24E-01	1.48E+00	4.037
Hexane	110543	2.59E-01	0.53E-00	1.446
Propylene Oxide	75569	2.96E-02	6.03E-02	0.164
Toluene	108883	1.33E-01	0.27E+00	0.737
Xylenes	1330207	6.53E-02	0.13E+00	0.355
Anthracene	120127	1.39E-05	2.83E-05	0.000
Benzo(a)anthracene	56556	4.39E-04	8.95E-04	0.002
Benzo(a)pyrene	50328	4.08E-02	8.32E-02	0.227
Benzo(b)fluoranthene	205992	1.13E-05	2.30E-05	0.000
Benzo(k)fluoranthene	207089	1.10E-05	2.24E-05	0.000
Chrysene	218019	2.52E-05	5.14E-05	0.000
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	4.79E-05	0.001
Naphthalene	91203	1.33E-03	2.71E-03	0.007
Diebenz(a,h)anthracene	53703	2.35E-05	4.79E-05	0.001
			Total HAP Emissions Per Year	7.491

Therefore, the total HAP emissions from Gas Turbines 5 and 7 (identical units) is
HAP = 7.491 * 2 = 14.98 tons/year

4. <u>FACILITY TOTAL</u>

The proposed ESPFM Project will consist of the following equipment:

One GE 7FA Combined Cycle Gas Turbine (CCGS) 8.35 tons/year
Two RR Trent 60 Simple Cycle Gas Turbines (SCGS) 3.15 tons/year
Existing Gas Turbines 5 & 7 14.98 tons/year
One Auxiliary Boiler 0.08 tons/year

The facility total HAP emissions are 26.55 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 1,030 MMBTU/scf. The emissions factors are converted to lb/MMSCF:

CO_2, 120,160 lb/MMSCF
CH_4, 2.27 lb/MMSCF
N_2O, 0.227 lb/MMSCF

In Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, the GWP for CO_2 is 1, the GWP for CH_4 is 21 and the GWP for N_2O is 310. Therefore, the total GHG emissions in terms of CO2e are calculated as:

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

CO2e emissions can also be expressed as a function of fuel usage, F

CO2e = 120,160* F + 2.27*21* F + 0.227*310* F = 120,278 * F (lb/MMSCF)
CO2e = 60.139 * F (tons/MMSCF)

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

1. CCGS (GE 7FA + Duct Burner)

The daily maximum GHG emissions is calculated as follows:

Q = 24 *2.365 MMSCF = 56.76 MMSCF/day

Daily maximum = 60.139 * 56.76 = 3,413 tons/day

The monthly GHG emissions is calculated based on the monthly fuel usage of 1,503.62 MMSCF

Monthly total = 60.139 * 1,503.62 = 90,426.20 tons/month

The annual fuel usage has been calculated to be 11,337.56 MMSCF. The corresponding GHG emissions are:

Annual total = 60.139 * 11,337.56 = 681,829.52 tons/year.

2. SCGS (Two RR Trent 60 Gas Turbines)

For each RR Trent 60 gas turbine the daily maximum GHG emissions is calculated based on the daily fuel usage of 24 * 0.501 MMSCF = 12.02 MMSCF/day.

Daily maximum = 60.139 * 12.02 = 722.87 tons/day

For each RR Trent 60 gas turbine the monthly GHG emissions is calculated based on the monthly fuel usage of 212.87 MMSCF.

Monthly total = 60.139 * 641.2 = 12,801.79 tons/month

For each RR Trent 60 gas turbine the annual fuel usage has been calculated to be 2,344.56 MMSCF. The corresponding GHG emissions:

Annual total = 60.139 * 2,344.56 = 140,999.49 tons/year

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

140,999.49 * 2 = 281,998.99 tons/year

3. Auxiliary Boiler

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 x 10^{-3} kg/MMBTU
N_2O, 1.0 x 10^{-4} kg/MMBTU

The emissions factors are associated with the assumption of natural gas HHV of 1,030 MMBTU/scf. The emissions factors are converted to lb/MMSCF:

CO_2, 120,160 lb/MMSCF
CH_4, 2.27 lb/MMSCF
N_2O, 0.227 lb/MMSCF

The fuel usage has been calculated to be 306 MMSCF/year, 25.96 MMSCF/month and 0.837 MMSCF/day for the auxiliary boiler. The GHG emissions are calculated below.

CO2e = 120,160 *306 + 2.27*21*306 + 0.227*310*306 = 18,402.54 tons/year
CO2e = 120,160*25.96 + 2.27*21*25.96 + 0.227*310*25.96 = 1,560.39 tons/month
CO2e = 120,160*0.837 + 2.27*21*0.837 + 0.227*310*0.837 = 50.34 tons/day

The combined total GHG emissions from the CCGS, SCGS, and the auxiliary boiler are:

CO2e: 681,829.52 + 281,998.99 + 18,402.54 = 982,231.05 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.

Combined Cycle Generation System (CCGS)

The following annual operating schedule is proposed for the CCGS:

Total Hours of Operation:	5,456 hours
Total number of Fast Start-ups:	150
Total number of Traditional Start-ups:	50
Total number of Shutdowns:	200

As previously determined, the net baseload operation, excluding startups and shutdowns, is 5,231 hours per year.

Power generated by the CCGS is provided by GE as shown in the Tables E-1 and E-2 below. The conditions at 100% load include operation of the duct burner.

Table E-1 – Power Generated by the CCGS

GE 7FA Baseload Conditions	100% load	45% load
Fast Start-ups, times per year	150	150
Traditional Start-ups, times per year	50	50
Shutdowns, times per year	200	200
Base load operation, hours per year	5,231	5,231
CTG power output, net kW(1)	222,000	222,000
ST power output, net kW(1)	112,000	112,000
CCGS power output, net kW	324,000	159,000
CCGS heat rate, net (Btu/kw-h, LHV)	6,754	7,480
Fuel input (mmBtu/hr, HHV)(1)	2,436	1,319
GE 7FA fuel usage, per year (mmscf)	11,337.56	7,065.03
Duct Burner fuel usage, per year (mmscf)	1,361.08	N/A
Total fuel usage, per year (mmscf)	12,698.64	7,065.03

(1) GE provided information

Power generated during the Fast Start-up, Traditional Start-up, Shutdown, and Base load operation are calculated.

Fast Start-up

A Fast Start-up takes 30 minutes.

GE 7FA Fast Start-up	Totals Over 30 Minute Period
Fast-Start-up fuel usage, MMBTU	728
CTG heat rate, Btu/kw-hour	7,072
Net power output, kw-hour	103,000

Traditional Start-up

A Traditional Start up takes 60 minutes.

GE 7FA Traditional Start-up	Totals Over 60 Minute Period
Traditional Start-up fuel usage, MMBTU	1,563
CTG heat rate, Btu/kw-hour	7,041
Net power output, kw-hour	222,000

Shutdown

A shutdown stakes 30 minutes.

GE 7FA Shutdown	Totals Over 30 Minute Period
Shutdown fuel usage, MMBTU	765
CTG heat rate, Btu/kw-hour	7,496
Net power output, kw-hour	102,000

Power Generation per Year

Total power generated by the CCGS in megawatt-hour is shown in Table E-2 below:.

Table E-2 – Annual Power Generation for the CCGS

Parameter	100% Load	45% Load
Fast Start-ups per year	150	150
Traditional Start-ups per year	50	50
Shutdowns per year	200	200
Base load operation (hours per year)	5,231	5,231
Power output per Fast-Start-up, MWh	103	103
Power output per Traditional startup, MWh	222	222
Power output per shutdown, MWh	102	102
Power output per base load hour, MWh	324	159

Power output, Fast-Start-up total, MWh	15,450	15,450
Power output, Traditional Start-up total, MWh	11,100	11,100
Power output, shutdown total, MWh	20,400	20,400
Power output, base load total, MWh	1,694,844	831,729
CCGS power generation in a year, MWh	1,741,794	878,679

Based on annual fuel consumption the CO2e emissions are calculated as follows:

CO2e = 60.139 * Fuel Usage
CO2e = 60.139 * 12,698.64 = 763,683.51 tons/year (100% load)
CO2e = 60.139*7,065.03 = 424,883.83 tons/year (45% load)

Parameter	100% Load	45% Load
CO2e emissions (tons/year)	763,683.51	424,884
CCGS power generation, MWh per year	1,741,794	878,679
CO2e, tons/net MWh	0.438	0.484
CO2e, lbs /net MWh	876.89	967.10

Simple Cycle Generating System (SCGS)

Because the SCGS consists of two identical Trent 60 gas turbines the GHG BACT analysis is conducted on one Trent 60 unit.

The following annual operating schedule is proposed for the SCGS:

Total hours of operation:	4,800 hours
Total number of startups:	480
Total number of shutdowns:	480

The net baseload operation, excluding startups and shutdowns, is 4,400 hours.

RR Trent 60 Baseload Conditions	100% load	55% load
Startups, times per year	480	480
Shutdowns, times per year	480	480
Base load operation, hours per year	4,400	4,400
CTG power output, net kW	55,000	22,000
CTG power output, gross kW	57,000	23,000
SCGS heat rate, net (Btu/kw-h, LHV)	8,321	11,842
Fuel input (MMBTU/hr, LHV)	466	264
Fuel input (MMBTU/hr, HHV)	516	292
Total fuel usage per year (mmscf)	2,344.56	1,385.36

Startup

A startup takes 30 minutes.

Trent 60 Start-up	Totals Over 30 Minute Period
Start-up fuel usage, MMBTU	181
CTG heat rate, Btu/kw-hour	9,504
Net power output, kw-hour	18,700

Shutdown

A shutdown stakes 20 minutes.

Trent 60 Shutdown	Totals Over 20 Minute Period
Shutdown fuel usage, MMBTU	91
CTG heat rate, Btu/kw-hour	18,299
Net power output, kw-hour	4,670

Power Generation per Year

Total power generated by the one Trent 60 gas turbine in net megawatt-hours is calculated in Table A-3 below. The total operating hours are assumed to be 4,800 hours per year.

Table A-3 – Annual Power Generation for the SCGS

Parameter	100% load	55% load
Startups per year	480	480
Shutdowns per year	480	480
Base load operation (hours per year)	4,400	4,400
Power output per startup, MWh	18.7	18.7
Power output per shutdown, MWh	4.67	4.67
Power output per base load hour, MWh	55	22
Power output, startup total, MWh	8,976	11,842
Power output, shutdown total, MWh	2,241	2,241
Power output, base load total, MWh	242,000	96,800
Power generation in a year, net MWh	253,217	110,883

Based on annual fuel consumption the CO2e emissions are calculated as follows:

CO2e = 60.139 * Fuel Usage
CO2e = 60.139 * 2,344.54 = 140,998.29 tons/year
CO2e = 60.139 * 1,385.36 = 83,292.51 tons/year

Parameter	100% load	55% load
Total fuel usage, per year (mmscf)	2,344.54	1,385.36
CO2e emissions (tons/year)	140,998.29	83,292.51
Net power generation, MWh per year	253,217	110,883
CO2e, tons/MWh, net	0.557	0.751
CO2e, lbs/net MWh	1,113.66	1,502.84

APPENDIX F – RULE 1325 PM2.5 EMISSIONS

The repower project has emission increases of PM2.5 from the installation of the new CCGS and SCGS gas turbines and the auxiliary boiler. The PM2.5 emissions are calculated as shown below:

CCGS:	51,833 lbs/year, as calculated in Table A-13
SCGS #1:	24,002 lbs/year, as calculated in Table B-11
SCGS #2:	24,002 lbs/year, as calculated in Table B-11
The Auxiliary Boiler:	540 lbs/year, as calculated in Table C-2

Total PM2.5 emissions from the new equipment:

PM2.5 = 51,833 +24,002*2 +540 = 100,377 lbs/year
PM2.5 = 50.19 tons/year = 275 lb/day (based on 365 days per year)

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

275 * 1.1 = 302.51 lb/day, or 303 lb/day

El Segundo Power, LLC would be required to provide 303 pounds per day of federally enforceable PM2.5 emission reduction credits, if the offset requirement is triggered.

FACILITY TOTAL PM2.5 EMISSIONS

During the previous Title V Facility Permit modification in 2010, the El Segundo Power, LLC's facility total PM2.5 potential to emit (PTE) was determined to be 51.8 tons per year. At that time, the facility elected to become a synthetic minor source for PM2.5 by accepting a permit condition to remain below 100 tons/year of PM2.5. (See Facility Permit Condition F2.1).

Boiler #3 PM2.5 PTE = 0.0066 lb/MMBTU * 3,350 MMBTU/hr * 8,760/2,000*112/335
= 32.37 tons/yr

Boiler #4 PM2.5 PTE = 0.0066 lb/MMBTU * 3,350 MMBTU/hr * 8,760/2,000
= 96.84 tons/yr

Facility PM2.5 PTE:

Parameter	PM2.5, tons/year
Existing Facility PTE	+51.8
ESPFM PTE	+50.19
Boiler #3 Retirement	(32.37)
Boiler #4 Retirement	(96.84)
Major Source Threshold	100
Major Source (Yes/No)	No

The new facility PM2.5 PTE does not exceed 100 tons per year. Therefore, the facility is not a major source for PM2.5 and no offsets are required.

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 below.

	GE 7FA	Trent 60	Trent 60	Auxiliary Boiler
NOx	148,226	46,675	46,675	521

The total RTC requirements are:

RTC, 1^{st} year = 242,088 lb/year

After the first year the anticipated annual NOx emissions are:

	GE 7FA	Trent 60	Trent 60	Auxiliary Boiler
NOx	117,786	37,880	37,880	521

The total RTC requirements are:

RTC, subsequent years = 194,067 lb/year