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AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

August 4, 2009

MIKE MONASMITH
PROJECT MANAGER
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO CA 95814

Dear Mr. Monasmith:

Enclosed is the District's Final Determination of Compliance for the Carlsbad Energy Center LLC's proposed development of the Carlsbad Energy Center Project (District Applications No. 985745, 985747, and 985748), a 558 megawatt combined cycled power plant consisting of two natural-gas-fired combustion turbine generators, each with a heat recovery steam generator and emission control equipment, and a diesel fire pump engine, to be located at 4600 Carlsbad Blvd, Carlsbad, California, on the same grounds as the existing Encina Power Station.

The District performed an evaluation of the air pollution impacts of this proposal and the equipment is expected to operate in compliance with all applicable District Rules and Regulations including all applicable state and federal requirements that the District is authorized to enforce. The proposed permit incorporates conditions necessary to ensure compliance with all these requirements.

Should you have any questions regarding this matter, please contact Steven Moore at (858) 586-2750.

Sincerely,

Steven Moore / for

TOM WEEKS
Chief of Engineering

Enclosures

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FINAL
DETERMINATION OF COMPLIANCE

CARLSBAD ENERGY CENTER PROJECT

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

Applications Number 985745, 985747, and 985748

August 4, 2009

Project Engineer	Camqui Nguyen
Senior Engineer:	Steven Moore
Application Numbers:	985745, 985747, and 985748
Site ID Number:	333A
Fee Schedule:	20F
BEC:	New

APPLICATION INFORMATION

Owner / Operator:	Carlsbad Energy Center, LLC
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Equipment Address:	4600 Carlsbad Blvd Carlsbad, CA 92008
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APPENDICES

I. PROJECT DESCRIPTION

Carlsbad Energy Center LLC (Applicant) proposes to develop the Carlsbad Energy Center Project (CECP). This project is a combined-cycle power plant with a total nominal base load gross power output of 558 MW. The CECP will utilize two Siemens SGT6-5000F Rapid Response Combined-Cycle (R2C2) combustion turbine generators (CTGs) equipped with steam power augmentation. The nominal gross power output is 208 megawatts (MW) with a corresponding heat input of 1976 million British thermal units per hour (MMBtu/hr) per turbine (without power augmentation at 61 ^{o}F average ambient temperature). The combustion turbines are also equipped with evaporative coolers that can be used to cool the inlet air to each turbine to increase power during periods of high ambient temperature. Each CTG is followed by a heat recovery steam generator (HRSG) equipped with a selective catalytic reduction (SCR) system to reduce oxides of nitrogen (NOx) emissions and an oxidation catalyst to control carbon monoxide (CO) and volatile organic compounds (VOCs) emissions. Steam from each HRSG will feed a steam turbine generator (STG) associated with that HRSG. This combination of a CTG with a HRSG and STG is referred to as a 1-on-1 combined-cycle power plant. By making use of the turbine exhaust heat to generate electricity with the steam turbine, combined-cycle power plants are significantly more efficient than other combustion turbine power plants.

The CECP is subject to the approval of the California Energy Commission (CEC) because the proposed power plant has a nominal rating greater than 50 MW. The Applicant filed an application for certification (AFC) with the CEC in September 2007 (07-AFC-6). The San Diego Air Pollution Control District (District) is considered a responsible agency for this approval and is required to submit a Preliminary Determination of Compliance (PDOC) and a Final Determination of Compliance (FDOC) to the CEC. Pursuant to District Rule 20.5 the FDOC review is functionally equivalent to an Authority to Construct review.

The CECP is located north of the intersection of Carlsbad Boulevard and Cannon Road in the city of Carlsbad in San Diego County. The project is proposed to be located in the northeast area of the existing Cabrillo Power I LLC's Encina Power Station, between the existing rail line and Interstate 5 (I-5). The two main power units of the project will be at the location of previously existing fuel oil tanks, which are currently being removed. Both Carlsbad Energy Center, LLC and Cabrillo Power I LLC, are indirect wholly owned subsidiaries of NRG Energy, Inc.

The existing Encina Power Station is comprised of five utility boilers using steam to generate a total of approximately 1000 megawatts (MW) of electrical power at full load and having a combined rated heat input of 9874 million British thermal units per hour (MMBtu/hr). The boilers are permitted to burn both natural gas and, in cases of force majeure natural gas curtailments, No. 6 fuel oil. As part of the CECP, three existing utility boilers, known as Units 1, 2, and 3, at the Encina Power Station will be retired when the two combined-cycled turbines are fully operational (the other two utility boilers will remain in operation).

The project will be fueled by natural gas, which will be supplied by the San Diego Gas and Electric Company. No provisions for use of an alternative fuel in the event of a curtailment of the natural gas supply are proposed by the Applicant.

II. EQUIPMENT DESCRIPTION

The Applicant has proposed to construct and operate the following equipment at this facility under application No. 985745, 985747, and 984748:

- Application 985745: Power block Unit #6 consisting of one nominal 208 MW (219 MW with steam augmentation) natural-gas fired combined-cycle Siemens SGT6-PAC5000F combustion turbine generator, serial number to be determined, with an ultra low NOx (ULN) combustor, an evaporative inlet air cooler, a heat recovery steam generator with a selective catalytic reduction unit, an oxidation catalyst, and a steam turbine generator and associated air-cooled heat exchanger to condense the exhaust steam from the steam turbine.

- Application 985747: Power block Unit #7 consisting of one nominal 208 MW (219 MW with steam augmentation) natural-gas fired combined-cycle Siemens SGT6-PAC5000F combustion turbine generator, serial number to be determined, with an ultra low NOx (ULN) combustor, an evaporative inlet air cooler, a heat recovery steam generator with a selective catalytic reduction unit, an oxidation catalyst, and a steam turbine generator and associated air-cooled heat exchanger to condense the exhaust steam from the steam turbine.

- Application 985748: An emergency fire pump engine, Cummins diesel engine, Model CFP6E-F35, as preliminarily proposed, rated at 246 brake horsepower, serial number to be determined.

III. PROCESS DESCRIPTION

The CECP consists of two power blocks, each having one CTG, one HRSG, and one condensing STG to provide a nominal 219 MW of electricity from the combustion turbine at full load with steam power augmentation and an additional 60 MW from the steam turbine. Thermal energy produced in the CTG through combustion of natural gas is converted to mechanical energy to drive the combustion turbine compressor and electric generator. The hot CTG exhaust gases at approximately 1,100°F enter the HRSG. In the HRSG, boiler feedwater is converted to steam and delivered to the STG. Steam leaving the steam turbine is condensed in an air-cooled surface condenser. Some of the steam from the HRSG is injected into the combustion turbine when steam power augmentation is employed.

The chosen combined-cycle system merges the fast starting capability of a simple-cycle gas turbine and the efficiency of a combined-cycle plant. The system is designed to start and reach 150 MW in ten minutes for a hot start and operate with combined-cycled efficiency in 45 minutes for a hot start and approximately 125 minutes for a cold start. The system is also designed to typically achieve its emission limits within 22 minutes. Traditional combined-cycle systems typically take 3–6 hours to reach comparable emission limits.

The one-hour averaged NOx emission concentration is controlled to 2.0 parts per million by volume on a dry basis (ppmvd) and corrected to 15 percent oxygen (O_2) by a combination of the ULN combustor in the CTG and the SCR system located in the HRSG. In the SCR, ammonia will be injected into the CTG exhaust stream via nozzles located upstream of the catalyst module. Ammonia slip, or the concentration of unreacted ammonia in the HRSG exhaust stack, is limited to 5.0 ppmvd averaged over one hour. The HRSG is also equipped with an oxidation catalyst to control CO emissions leaving the HRSG exhaust stack to 2.0 ppmvd and VOC emissions to 1.5 ppmvd averaged over one hour. Exhaust from each HRSG will be discharged from individual 21.3-foot diameter stacks proposed to be 139-foot tall.

Each CTG is equipped with a continuous emission monitoring systems (CEMS) to sample, analyze, and record the natural gas fuel flow rate, NOx and CO concentration levels, and percentage of O_2 in the exhaust gas from the HRSG stack. The data will be transmitted to a data acquisition and handling system (DAHS) that will store the data and generate emission reports. The DAHS will also include alarms that will send signals to the plant distributed control system (DCS) when emission limits are approached or exceeded.

Because of regional system needs, the CECP is expected to operate primarily at intermediate average annual capacity factors. The facility is designed to operate between 25 and 100 percent of the base load (558 MW) to support dispatch service in response to customer electricity demands. The basic operational modes primarily affecting emissions are startups, shutdowns, short transients, and normal operations. The Applicant has provided CTG performance data and emission data based on vendor guarantees for operations under different loads and different ambient temperatures. The expected emissions used in various aspects of the evaluation are presented in Tables 1a and 1b.

Startup is defined as the period beginning with ignition of a combustion turbine and lasting until the turbine can achieve the most stringent emission limits during normal operations (for this turbine the manufacturer has guaranteed turbine emissions at greater than 60% of base load capacity (114 MW at annual average ambient temperature without steam augmentation). Shutdown is a period beginning with the lowering of the output of a combustion turbine below the minimum load necessary to achieve the most stringent emission limits during normal operations of its load capacity and ending when combustion has ceased. The minimum load is typically between 40% and 60% of the maximum load, depending on the combustion turbine. The Applicant has proposed a minimum load threshold for a shutdown to be initiated of 114 MW. Although typical startups and shutdowns are expected to take 22 minutes and 7 minutes, respectively, the permit conditions allow 60 minutes for a startup and 30 minutes for a shutdown to allow for contingencies during these operations.

Emissions during startups and shutdown are significantly higher than during steady state operation. However, because of its unique design, the plant will be able to startup and achieve emission limits much faster than conventional large combined-cycle power plants. The Applicant estimates that there will be 300 typical startups per turbine per year and 300 typical shutdowns per turbine per year. Maximum annual emissions are calculated based on 300 hours with a startup, 300 hours with a shutdown, and 3,500 hours per year at full-load operation under average conditions for both CTGs.

The CECP may be completed in two phases expected to end in 2012 with the two combustion turbines sequentially achieving full operation. Phase I would consist of bringing one CTG/STG to full operation. Phase II would consist of bringing the remaining CTG/STG to full commercial operation. The completion of these two phases could be separated by as much as six months. Consequently, the three existing utility boilers may also be retired, or have their operations limited, in two phases. During the phase-in process the Applicant has committed to not operating the combustion turbines and the steam boilers simultaneously, which minimizes emission impacts. However, to maintain grid reliability, maximum flexibility is desired in operating the existing boilers during the phase-in process when one or both CTG/STG units may not be fully operational.

IV. EMISSION ESTIMATES

COMBUSTION TURBINE GENERATOR EMISSIONS—STANDARD OPERATIONS

MAXIMUM HOURLY EMISSIONS

Project emissions of NOx, CO, sulfur oxides (SOx), VOCs, particulate matter less than or equal to 10 microns in diameter (PM10), and particulate matter less than or equal to 2.5 microns in diameter (PM2.5) were estimated based on data supplied by the turbine manufacturer and emission limits in the FDOC permit conditions. The startup and shutdown, emission rates were provided by the turbine manufacturer. For normal operations, emission rates for NOx, CO, and VOCs are calculated based on emission concentration limits (in ppmvd at 15% O_2) in the FDOC permit conditions and exhaust flow rates in dry standard cubic feet per hour (dscfh) at an average ambient temperature of 73.8 °F with the evaporative cooler operating, but without steam augmentation, for annual emissions (Case 2 in Table 5.1B-5 in the application) and at cold ambient temperature, 37.4 °F, without steam augmentation, for peak hour and peak day emissions (Case 15 in Table 5.1B-5 in the application):

> Emissions, lbs/hr = (concentration, ppmvd) x 10^{-6} x (exhaust flow rate, dscfh) x (molecular weight/standard molar volume).

The Case 15 provides the highest emissions among the 21 turbine operating scenarios considered (second highest was Case 1, operations at the average ambient temperature case with steam augmentation). The FDOC conditions limit peak hourly emissions based on this operating scenario. Case 2 is expected to be most representative of annual average emissions.

Maximum hourly emissions of SOx are calculated based on the fuel heat input MMBtu/hr, and a SOx emission factor of 0.0021 lbs/MMBtu, which was derived from the maximum allowable sulfur content of 0.75 grains per 100 standard cubic feet based on the California Public Utility Commission (PUC) standard for pipeline natural gas. Emissions of PM10 are calculated based on vendor supplied guaranteed emission rates. Table 1a presents the hourly emission rates in pounds per hour (lbs/hr) for all five criteria pollutants at cold ambient temperature (37.4°F) and average ambient temperature (73.6°F). The PM2.5 emission rates are identical to PM10 emission rates since all particulate matter is considered to be PM2.5.

Table 1a – Maximum Turbine Emission Rates During Normal Operations			
Pollutant	Concentration, ppmvd @15%O2	Emission Rate at Cold Ambient Temperature, lb/hr	Emission Rate at Average Ambient Temperature, lbs/hr
NOx	2 (1- hour average)	15.1	14.13
CO	2 (1-hour average)	9.2	8.6
VOCs	1.5 (1-hour average)	4.0	3.7
PM10	N/A	9.5	9.5
PM2.5	N/A	9.5	9.5
SOx	N/A	4.4	4.1

During a CTG startup, there are typically approximately 22 minutes of emission rates higher than emissions during normal operation. Therefore, typical hourly emission rates during startup are based on 22 minutes of high emission levels followed by 38 minutes of normal operation emission levels. During a typical CTG shutdown, there are approximately 53 minutes of normal operation followed by 7 minutes of higher emission levels. Therefore, typical hourly emission rates during shut down are based on 53 minutes of normal operation emission levels followed by 7 minutes of higher emission levels. For any hour when both a typical startup and a shutdown occur, there would be 22 minutes of startup emissions, 31 minutes of normal emissions and 7 minutes of shutdown emissions. Because there is some variability in emissions during startup and shutdown, the higher startup and shutdown emissions for CO and NOx are estimated at twice the expected emission value. Normal operation emissions were assumed to correspond to those at cold ambient temperature with in calculating the hourly emission rates.

Table 1b presents the maximum emission rates for each turbine during startup and shutdown in pounds per hour. The maximum emission rates of PM10 and PM2.5 are not affected during startup and shutdown and the emission limit for normal operations remains in effect for these periods. The maximum emission rate of SOx is reduced because the turbine operates at low loads (and low heat input) during startups and shutdowns.

Table 1b –Maximum Turbine Emission Rates During Startup and Shutdown			
Pollutants	Startup Emissions, lbs/hr	Shutdown Emissions, lbs/hr	Startup and Shutdown, lbs/hr
NOx	69.2	47	86
CO	545	286	814
VOCs	15.5	8.2	19.8
PM10	9.5	9.5	9.5
PM2.5	9.5	9.5	9.5
SOx	<4.4	<4.4	<4.4

Maximum Daily Emissions

Maximum daily emissions from each combustion turbine are calculated based on the assumption that each turbine operates up to 24 hours per day, of which 6 hours include a startup, 6 hours include a shutdown, and 12 hours for maximum normal operation at cold ambient temperature, as follows:

Daily emissions = (startup emissions, lbs/hr) x (6 hours/day) + (shutdown emissions, lbs/hr) x (6 hours/day) + (normal operation emissions, lbs/day) x (12 hours /day)

Table 1c presents estimated maximum daily emissions from the combustion turbines in pounds per day (lbs/day).

Table 1c – Expected Maximum Turbine Daily Emissions		
Pollutants	Emissions from Each Turbine lbs/day	Emissions from Both Turbines lbs/day
NOx	877	1754
CO	5102	10205
VOCs	190	380
PM10	228	456
PM2.5	228	456
SOx	106	211

Maximum Annual Emissions

Maximum annual emissions for the combustion turbines are estimated based on the assumption that each turbine operates up to 4100 hours per year, of which 300 hours are for startup, 300 hours are for shutdown, and 3500 hours for maximum normal operation at average ambient temperature, as follows:

Annual emissions = (startup emissions, lbs/hr) x (300 hours/year) + (shutdown emissions, lbs/hr) x (300 hours/year) + (normal operation emissions, lbs/day) x (3500 hours /years)

Table 1d presents estimated maximum turbine annual emissions in tons per year (tons/yr).

Table 1d – Maximum Turbine Annual Emissions		
Pollutants	Emissions from Each Turbine, tons/yr	Emissions from Both Turbines, tons/yr
NOx	37.77	75.54
CO	108.65	217.3
VOCs	10.03	20.05
PM10	19.48	38.95
PM2.5	19.48	38.95
SOx	8.43	16.9

Note that the annual SOx emissions are based on the PUC limit for sulfur content of natural gas. Historically, the annual average sulfur content in San Diego natural gas has been significantly less.

EMERGENCY FIRE PUMP ENGINE EMISSIONS

At a minimum, the diesel emergency fire pump engine must comply with Tier 2 emission standards for EPA certified engines of model year 2009. Daily emissions from the engine are calculated based on one hour of operation and annual emissions are calculated based on 50 hours of operation. Table 2a presents the engine hourly, daily, and annual emissions.

Table 2a – Emergency Fire Pump Engine Emissions			
Pollutant	Engine Hourly Emissions, lbs/hr	Engine Daily Emissions, lb/day	Engine Annual Emissions, tons/yr
NOx	2.08	2.08	0.052
CO	0.24	0.24	0.006
VOCs	0.05	0.05	0.00125
SOx	0.0027	0.0027	0.00007

PM10	0.035	0.035	0.0008
PM2.5	0.035	0.035	0.0008

PROJECT EMISSIONS—STANDARD OPERATIONS

Standard operations are those operations occurring after of the commissioning period for a turbine (see below). Total emissions from the project include emission from both combustion turbines and emissions from the emergency fire pump engine. Table 3a and 3b present the estimated maximum project total daily and annual emissions pounds per day and tons per year, respectively.

Table 3a – Maximum Project Total Daily Emissions

Pollutant	Turbines Total Daily Emissions, lbs/day	Engine Daily Emissions, lbs/day	Project Total Daily Emissions, lbs/day
NOx	1754	2.08	17569
CO	10205	0.24	10205
VOCs	439	0.05	439
SOx	211	0.0027	211
PM10	4569	0.035	4569
PM2.5	4569	0.035	4569

Table 3a – Maximum Project Total Annual Emissions			
Pollutant	Turbines Total Annual Emissions, tons/yr	Engine Annual Emissions, tons/yr	Project Total Annual Emissions, tons/yr
NOx	75.54	0.052	75.6
CO	217.3	0.006	217.3
VOCs	20.05	0.00125	20.05
SOx	16.9	0.00007	16.9
PM10	38.95	0.0008	39
PM2.5	38.95	0.0008	39

Toxic air contaminant emissions, or noncriteria pollutant emissions, are presented in the Toxic Health Risk Assessment Section in Appendix B.

COMBUSTION TURBINE GENERATOR EMISSIONS—COMMISSIONING PERIOD

Following construction of the power plant and prior to full commercial operation, the combustion turbine generators, the steam turbine generator, emission control equipment, heat recovery steam generator and other equipment will be tested and tuned. During this commissioning period, because the CTG burners may not yet be tuned for optimal emissions and because the postcombustion control equipment will not yet be in full operation, emissions from the plant will be higher than standard operating emissions. Each turbine is expected to operate 415 hours over approximately 49 operating days during this commissioning period, which includes startups and shutdowns, hours of operation at different load levels, and operation with and without emission control equipment. Commissioning emission data provided by the turbine vendor consist of different emission scenarios corresponding to different phases of the commissioning period. Table 4a presents the expected commissioning maximum hourly emission rates. In order to minimize emission impacts during the commissioning period, emission rates for NOx and CO for both turbines combined will be limited to the levels expected for one turbine in commissioning mode and one turbine in standard mode (including startups and shutdowns) by the FDOC permit conditions.

Table 4a –Maximum Turbine Hourly Emissions During Commissioning		
Pollutants	Single Turbine Emissions, lbs/hr	Allowed Combined Turbine Emissions, lbs/hr
NOx	200	286
CO	3813	4627
VOCs	164	184
SOx	4.4	8.8
PM10	9.5	19.0
PM2.5	9.5	19.0

For a single combustion turbine, expected maximum daily emissions during commissioning are based on the peak emission day for each pollutant as forecast from the projected commissioning schedule. Because of the FDOC hourly limits on NOx and CO emission rates during commissioning, peak daily emissions during commissioning from both turbines for NOx and CO are estimated as the sum of the peak commissioning emissions for one turbine and expected maximum daily emissions from the other turbine under standard operations. For the other pollutants, peak daily commissioning emissions are the sum of peak commissioning emissions for each turbine. Table 4b presents the maximum daily commissioning emissions. The entire commissioning period may take up to 120 calendar days for each turbine to allow time for reviewing test and turning information and making operational adjustments to the combustion turbines and associated plant equipment.

Table 4b – Maximum Daily Emissions During Commissioning		
Pollutants	Single Turbine Emissions, lbs/day	Combined Turbine Emissions, lbs/day
NOx	1755	2632
CO	43712	48814
VOCs	1310	1500
SOx	106	211
PM10	221	442
PM2.5	221	442

Total commissioning emissions are based on turbine vendor projected emission data for the entire commissioning period. The emergency fire pump engine is not expected to operate during the turbine commissioning period. Table 4c presents total commissioning emissions. Note that these emissions include all emissions from startups and shutdowns during the commissioning period.

Table 4c – Total Annual Turbine Commissioning Emissions		
Pollutants	Single Turbine Emissions, tons	Combined Turbine Emissions, tons
NOx	6.24	12.48
CO	65.17	130.34
VOCs	3.48	6.96
SOx	0.28	0.56
PM10	1.96	3.92
PM2.5	1.96	3.92

PROJECT EMISSIONS—COMMISSIONING PERIOD

For the combustion turbines' first year of operation during which both commissioning operations and standard operations take place, total maximum project emissions are estimated based on 415 hours of commissioning emissions, 300 hours of maximum startup emissions, 300 hours of maximum shutdown emissions, and 2,600 hours of maximum normal operation emissions at annual average ambient temperature, and estimated maximum emissions from the emergency fire pump engine. Table 4d presents the estimated total maximum annual emissions for the project for a year with commissioning.

Table 4d – Total Project Emissions During Year With Commissioning

Pollutants	Combined Turbine Commissioning Emissions, tons/yr	Combined Turbine Standard Operation Emissions and Engine Emissions, tons/yr	Total Project Emissions, tons/yr
NOx	12.48	62.87	75.35
CO	130.34	209.56	339.90
VOCs	6.96	16.74	23.7
SOx	0.56	13.15	13.71
PM10	3.92	30.40	34.32
PM2.5	3.92	30.40	34.32

V. RULES ANALYSIS

DISTRICT AND FEDERAL NSR AND PSD REGULATIONS

Rule 20.1(c)(35) – Major Stationary Source

Major stationary source means any emission unit or stationary source which has, or will have after issuance of a permit, an aggregate potential to emit one or more air contaminants, including fugitive emissions, in amounts equal to or greater than any of following emission rates:

Air Pollutant	Emission Rates (tons/yr)
PM10	100
NOx	50
VOCs	50
SOx	100
CO	100
Lead (Pb)	100

Major source status is only relevant for pollutants for which the District does not attain an applicable national air quality standard. Since the District attains all national ambient air quality standards with the exception of ozone, major source status is only relevant for NOx and VOCs, both of which are ozone precursors. In particular, the major modification thresholds (see below) apply for contemporaneous emission increases and associated requirements for NOx and VOCs. Based on its potential to emit, the Encina Power Station is an existing major stationary source for both NOx and VOCs.

Rule 20.1(c)(58) – Prevention of Significant Deterioration (PSD) Stationary Source and 40 CFR 52.21

Because the Encina Power Station is a fossil fuel fired steam electrical generating plant with a heat input rating greater than 250 MMBtu/hr, PSD Stationary Source status is defined by an aggregate potential to emit one or more air contaminants in amounts equal to or greater than any of the following emission rates:

Air Pollutant	Emission Rates (tons/yr)
PM10	100
PM2.5	100
PM	100
NO_2	100
VOCs	100
SO_2	100
CO	100
Lead (Pb)	100

Since the Encina Power Station's potential to emit exceeds the PSD stationary source threshold for at least one pollutant (e.g., NOx, which is considered NO_2 for purposes of PSD determinations), it is an existing PSD stationary source. District Rule 20.1 does not explicitly address PM2.5 or particulate matter of all sizes (PM). However, those pollutants are addressed by 40 CFR 52.21 et. seq., which is EPA's implementation of PSD rules and is an applicable requirement for the CECP under the federal Operating Permit Program (Title V).

Rule 20.1(c)(16), 40 CFR §52.21, and 40 CFR Appendix S to Part 51– Contemporaneous Emission Increase

Contemporaneous emission increase is defined in Rule 20.1 (c)(16) as the sum of emission increases from new or modified emission units occurring at a stationary source within the calendar year in which the subject emission units is expected to "commence operation" and the preceding four calendar years, including all other emission units with complete applications under District review and which are expected to commence operation within such calendar year. The emission increases for new units are based on the new units' potential to emit (PTE) as limited by the FDOC permit limits pursuant to Rule 20.1(d)(1)(i)(A). The emission increases may also be reduced by actual emission reductions at the facility. In this case, the Applicant is proposing to create actual emission reductions by shutting down three existing utilities boilers, Units 1, 2, and 3 with District permit Nos. 791, 792, and 793, respectively (the two other utility boilers, Units 4 and 5, will remain in operation).

Rule 20.1(c)(16) does not address when the actual emission reductions must occur relative to the initial startup of new or modified equipment. However, for replacement units, up to 180 days from the initial startup of new equipment is allowed before the actual emission reduction must be effective in federal implementations of PSD regulations [40 CFR §52.21(b)(3)(ii) and (viii)] and nonattainment NSR regulations [40 CFR Appendix S to Part 51 II.a.6.ii. and vi.] to allow a reasonable shakedown period for the new equipment.

The CECP is replacing the three existing utility boilers known as Units 1, 2, and 3 at the Encina Power Station. At the end of Phase I of the project, full commercial operation for one of the CTG/STG systems, part of the electrical generating capacity of these three boilers will be replaced. The generating capacity of Units 1, 2, and 3 will be completely replaced by the end of Phase II when the second CTG/STG system is fully operational. Since the new CTG/STG systems are replacing these three existing boilers, simultaneous operation of the CTG/STGs and the three existing boilers is not allowed during the phase-in period and the boilers must be shutdown completely at the end of Phase II.

In this case, 180 days is a reasonable shakedown time for each new CTG and associated equipment. This shakedown period allows 120 days for new equipment commissioning, which includes achieving the most stringent permitted emission limits, and an additional 60 days for the new equipment to reach full commercial operational status including verification testing both for emissions and operational reliability. The shakedown periods for the two CTG/STG systems could proceed in parallel or sequentially.

<u>Preproject Actual Emissions</u>

Existing Units 1, 2, and 3 at the Encina Power Station will be shut down and retired prior to full commercial operation of both new CTG/STG systems. In addition, their operations will be limited by permit conditions at the end of Stage I of the project. The limited operation and eventual shutdown of these boilers will result in an actual emissions reduction at the site. Rule 20.1(c)(16)(i) allows the sum of emission increases to be reduced by actual emission reductions occurring at the stationary source. Rule 20.1(d)(4)(ii)(A) defines actual emission reductions from the shutdown of an emission unit as those calculated based on the emission unit's preproject actual emissions (baseline emissions).

Baseline emissions are based on actual emissions occurring over the 5-year period preceding the receipt of the application. Rule 20.1(d)(2)(i)(B) requires the actual emissions to be averaged over the total operational time period within the five-year period if a representative two-year operating time period does not exist. Since the Application for Certification (AFC) for the CECP was submitted to the CEC in 2007, the preceding five years in consideration for actual emission reduction estimates are 2002, 2003, 2004, 2005, and 2006.

Units 1, 2, and 3 at the Encina Power Station have been used in recent years more as peaking units than base-load units. Peaking units are typically only called on to operate by the California Independent System Operator (ISO) when high electrical demand requires additional power beyond that provided by more efficient base-load units. This additional power is necessary to provide electrical grid stability. As such, the units' operation may vary greatly from year to year depending on the weather, which largely determines electrical demand, and availability of electrical generating assets not only in California but throughout the Western United States. Therefore, the District concluded that, because of the variable nature of the operations, no consecutive two-year period was representative of actual emissions from the three units. Since the District determined that there was not a representative two-year operating time period for Units 1, 2, and 3 of the Encina Power Station during these five years, the 5-year average of emissions determines baseline emissions for these units.

The five boilers at the Encina Power Station exhaust through a single common stack known as the common unit chimney (CUC). For purposes of recording emissions pursuant to the federal Acid Rain Program, there is a NOx CEMS on the CUC. This CEMS was installed prior to 2000. However, this CEMS measures and records NOx emissions from all five boilers combined.

However, each unit is currently equipped with an individual certified CEMS that measures and records NOx emissions for each hour of operation to determine compliance with District Rule 69. In addition, as part of the NOx CEMS system for each unit, the hourly natural gas fuel and liquid fuel use and power output for each unit is measured by instruments subject to federal Acid Rain Program quality assurance and quality control requirements (the information is required both to determine compliance with District Rule 69 and as part of the Acid Rain Program). The individual unit CEMS on Units 1, 2, and 3 were installed in 2003 when selective catalytic reduction (SCR) add-on emission control systems and low-NOx burners were installed on these units, which greatly reduced their NOx emissions. In 2002, each unit's fuel flow and power output was still measured and recorded for the Acid Rain Program.

The unit-specific fuel use and power output information is recorded hourly by the individual unit CEMS data acquisition and handling system (DAHS) for purposes of Rule 69 compliance and also transmitted to the Acid Rain Program CEMS on the CUC where it is separately recorded for the purposes of the Acid Rain Program. Because the data is used for different purposes and recorded pursuant to different protocols (and also, possibly, subject to instrument bias), there can be differences in the fuel use and power output recorded for purposes of Rule 69 and the Acid Rain Program. Notably, fuel use for Rule 69 is not recorded during the early portions of a unit's startup when Rule 69 is not applicable while it is recorded at all times for the Acid Rain Program. In addition, the Acid Rain Program may employ data substitution algorithms that are not used for Rule 69 and may be less representative of actual fuel use.

Baseline NOx emissions for 2004–2006 are based on the recorded NOx emissions from the individual CEMS on Units 1, 2, and 3 for purposes of Rule 69 compliance. Using the Rule 69 compliance emissions understate actual baseline NOx emissions since, as with fuel use, NOx emissions during the early portions of a unit's startup are not reported for purposes of Rule 69.

For 2002, the NOx emissions from Units 1, 2, and 3 were much larger since SCR had not yet been installed. However, the NOx emissions in excess of the currently applicable standard in Rule 69, 0.15 pounds per megawatt-hour (lb/MW-hr), were not allowed for the baseline calculations. Therefore, emissions were calculated based on the hourly power output recorded for each unit by the individual unit CEMS and the Rule 69 emission standard.

In 2003, the SCR were installed and operational on each unit before the individual unit CEMS were certified for measurement of NOx emissions. The NOx emissions were not recorded by the individual unit CEMS prior to certification. Therefore, NOx emissions for 2003 prior to the CEMS certification were estimated based on the hourly power output for each unit and, since SCR was installed, an average emission rate in pounds per megawatt-hour calculated for each unit after CEMS certification (the average was about 0.11 lb/MW-hr for each unit). Emissions of NOx after the CEMS certification in 2003 is based on the emissions measured by each unit's CEMS. This was a refinement of the procedure used in the PDOC which assumed that the emissions prior to CEMS certification were at a rate of 0.15 lb/MW-hr. This refinement in the calculation procedure results in a reduction of the 5-year NOx baseline emissions by about 2% (0.65 tons per year)

For the other criteria pollutants—CO, VOCs, SOx, PM10, PM2.5, and PM—the baseline emissions are calculated by multiplying the fuel use by an appropriate emission factor. For the PDOC, the baseline emissions for these pollutants were based on the District's annual emission inventory reports, which in turn are based on fuel use reported by the facility for each year. For the Encina Power Plant, the annual fuel use values reported to emission inventory are from the North American Electric Reliability Corporation-Generating Availability Data System (NERC-GADS), which integrates the fuel use for each unit recorded by the individual unit flowmeters. The NERC-GADS system annual fuel use is then manually recorded. As noted above, fuel use is also recorded for purposes of Rule 69 by individual unit CEMS and for purposes of the Acid Rain Program by the CUC CEMS.

For this FDOC, after an extensive examination of the three sources of fuel use data, the District has concluded that the most appropriate fuel use data for natural gas for purposes of determining preproject actual emissions is that recorded in the individual unit CEMS for purposes of Rule 69 compliance, where available, and the Acid Rain Program fuel use data prior to the certification of the individual CEMS. As noted above, the use of the Rule 69 fuel use likely understates actual fuel use and results in conservatively low (about 1%) emission estimates of baseline emissions. The 5-year average Rule 69 fuel use is about 2% less than that used in the District emission inventories.

For the liquid fuel (No. 6 fuel oil, also referred to as residual fuel oil), the emission inventory fuel use was used. With the exception of SOx, liquid fuel combustion contributes very little to emissions from these units (less than 2%).

The District also refined the emission inventory calculations for purposes of determining baseline emissions as follows:

- The unit-specific annual source tests for each year, where available (2003-2006), were used to calculate emissions from natural gas combustions for CO and PM for each year (EPA's preferred method),

- The PM emission factor for residual fuel oil combustion was slightly lowered from the standard emission inventory value to be consistent with the AP-42 emission factor, which was used to calculate PM10 and PM2.5 emissions from No. 6 (residual) fuel oil combustion, and

- A corrected calculation methodology for PM and SOx emissions from No. 6 fuel oil combustion in 2005 was used (the corrected methodology is the same as the methodology used for all other years in the PDOC).

For this FDOC, the District has recalculated estimated emissions for CO, VOCs, SOx, PM10, PM2.5, and PM based on the individual CEMS natural gas fuel use data and with the refinements in the emission calculations listed above. As compared to the PDOC, this results in decreases in baseline emissions for CO and VOCs of about 5.5% and 2.5%, respectively, an increase in SOx baseline emissions of about 4%, and almost no change in PM10, PM2.5 and PM emissions.

Table 5a presents the FDOC preproject actual emissions.

Table 5a – Boiler Units 1,2, and 3 Preproject Actual Emission						
Pollutants	2002 Actual Emissions, tons/yr	2003 Actual Emissions, tons/yr	2004 Actual Emission, tons/yr	2005 Actual Emission, tons/yr	2006 Actual Emission, tons/yr	Baseline Average Emissions, tons/yr
NOx	39.99	27.7	46	31.73	16.17	32.21
CO	494.59	344.03	266.73	144.25	94.43	268.80
VOCs	16.18	14.83	22.14	15.41	8.11	15.33
SOx	9.53	12.51	2.41	3.69	2.59	6.15
PM10	34.97	27.66	45.28	33.58	15.97	31.49
PM 2.5	34.80	27.43	45.28	33.54	15.93	31.40
PM	35.22	28.01	45.28	33.64	16.02	31.64

<u>Postproject Contemporaneous Emission Increase</u>

Currently, the proposed CECP is expected to commence full commercial operation in 2012. Full commercial operation includes having both CTGs and associated STGs fully operational with their emission and operational status verified. Therefore, the five-year contemporaneous window in which emission increases need to be evaluated is the time period from 2008 through 2012. For the years 2008 to 2012, there are no expected emission increases at the Encina Power Station. In addition, the District has no applications associated with the Encina Power Station other than the CECP that expect to commence operation at any time in the future. Therefore, the only emission increases for contemporaneous emission increases are those associated with the CECP.

For informational purposes, Table 5b presents the contemporaneous emission increases at the site without consideration of the FDOC permit limits after completion of all phases of the CECP and the retirement of existing Units 1, 2, and 3. The increase is calculated based on the total expected emission increase resulting from the CECP and actual emission reductions due to shutting down of the three existing utility boilers. The maximum annual emissions are based on the larger of the emissions during a standard operation year or a commissioning year.

Table 5b –Emission Increases for Estimated Maximum CECP Emission Increases			
Pollutants	Estimated Maximum Emission Increases from CECP, tons/yr	Actual Emission Reductions from Units 1, 2, and 3, tons/yr	Maximum Potential Emission Increase, tons/yr
NOx	75.6	32.21	43.39
CO	339.9	268.8	71.10
VOCs	23.7	15.33	8.4
SOx	16.9	6.2	10.7
PM10	39	31.5	7.5
PM 2.5	39	31.4	7.6
PM	39	31.64	7.4

However, the actual contemporaneous emission increase, which includes limitations on potential to emit of the new equipment accepted by the Applicant, are shown in Table 5c. These limits are applicable from the first date a turbine has an initial startup. These limits were accepted by the Applicant to ensure annual emissions did not exceed those upon which the Ambient Air Quality Analysis (AQIA) was based (see below) and to ensure emissions were limited to below the major modification and PSD modification thresholds (see below). Note that all particulate matter emissions from the CECP are considered to be PM2.5, so a limit on PM10 suffices to limit PM2.5, PM10, and PM.

Table 5c – Contemporaneous Emission Increases				
Pollutants	Maximum Year	Allowed PTE Increases From CECP, tons/yr	Actual Emission Reductions from Units 1, 2, and 3, tons/yr	Contemporaneous Emission Increase, tons/yr
NOx	Standard	72.11	32.21	39.9
CO	Commissioning	339.9	268.8	71.10
VOCs	Commissioning	23.7	15.33	8.4
SOx	Standard	5.6	6.2	-0.6
PM10	Standard	39	31.5	7.5
PM2.5	Standard	39	31.4	7.6
PM	Standard	39	31.64	7.4

<u>Contemporaneous Emission Increases After Completion of the Phase I Shakedown Period</u>

The CECP contemplates starting operation of the two CTG/STG units sequentially. The second unit to reach full commercial operation (Phase II) may complete its shakedown period significantly later than the first (Phase I). To allow for this possibility, contemporaneous emission increases were evaluated for the operation of a single combustion turbine and the emergency fire pump only.

The Applicant agreed to accept emission limits, as necessary, on the single combustion turbine and emergency fire pump combined and Units 1, 2, and 3 to limit emissions below the PSD modification thresholds for pollutants for which the District attains the national ambient air quality standards, and, in the case of NOx and VOCs, limit emissions to a level below the major modification threshold or to a level consistent with the emission offsets provided (see below).

Only CO, PM2.5, and PM10 emissions from Units 1, 2, and 3 need to be limited in Phase I to provide actual emission reductions to prevent triggering the PSD modification or major modification thresholds. For VOCs, SOx, and PM, the FDOC permit conditions limit the emissions of the new equipment in Phase I to less than the major modification threshold (VOCs) or the PSD modification threshold (SOx and PM) without consideration of actual emission reductions from the existing equipment. For NOx, the allowed emission increase for the new equipment in Phase I is less than the PSD modification threshold but does constitute a major modification. However, the FDOC permit conditions require surrender of sufficient emission reduction credits prior to the new equipment operation to fully offset this increase without consideration of actual emission reductions. Therefore, limits on emissions for NOx, VOCs, SOx, and PM from Units 1, 2, and 3 are not necessary.

Consistent with the necessary shakedown period for the CTG/STG system (not to exceed 180 days), the actual emission reductions need not occur until the end of shakedown period for the first turbine to reach full commercial operation (i.e., before that time emissions from the three existing utility boilers are not limited other than being prohibited from operation whenever a combustion turbine of the CECP is operated during the shakedown period,). Therefore, the emission limits for Units 1, 2, and 3 do not apply until the end of the 180-day shakedown period for Phase I.   However, the limits on potential to emit for the combustion turbine and emergency engine combined apply from the first date a combustion turbine has an initial startup (also known as “first fire”). During the shakedown periods for both turbines the limits on potential to emit for both combustion turbines and the emergency engine listed in Table 5c are also in effect, which serves to limit the potential to emit of all the emission units associated with the CECP during both phases of the shakedown period.

The Phase I limits in Table 5d and 5e are no longer applicable at the end of the shakedown period for the second CTG/STG system (i.e., the end of Phase II). At that time the limits in Table 5c apply to both combustion turbines and the emergency generator combined, and Units 1, 2, and 3 must permanently cease operation.

Table 5d presents the resulting actual emission reductions from emission limitations on the three existing utility boilers at the end of Phase I and Table 5e presents the resulting contemporaneous emission increases and limitations on the potential to emit for one turbine and the emergency fire pump engine combined for Phase I.

Table 5d – Phase I Actual Emission Reductions			
Pollutants	Baseline Emissions from Units 1, 2, and 3, tons/yr	Allowed Emissions from Units 1, 2, and 3, tons/yr	Actual Emission Reductions, tons/yr
NOx	32.21	No Limit	0
CO	268.80	198.75	70.05
VOCs	15.33	No Limit	0
SOx	6.15	No Limit	0
PM10	31.49	26.89	4.6
PM2.5	31.40	21.80	9.6
PM	31.64	No Limit	0

Table 5e – Phase I Contemporaneous Emission Increases			
Pollutants	Allowed Emission Increases from One Turbine and Emergency Fire Pump Engine, tons/yr	Actual Emission Reductions from Units 1, 2, 3, tons/yr	Contemporaneous Emission Increase, tons/yr
NOx	36.05	0	36.05
CO	169.95	70.05	99.9
VOCs	11.85	0	11.85
SOx	2.8	0	2.8
PM10	19.5	4.6	14.9
PM2.5	19.5	9.6	9.9
PM	19.5	0	19.5

<u>Contemporaneous Emission Increases After Phase II</u>

After commissioning of both turbines has been completed (end of Phase II), expected emissions for CO and VOCs are reduced. The Applicant has agreed to accept annual emission limits for these pollutants that reflect the lower expected annual emissions. The contemporaneous emission increases applicable to postcommissioning operations are given in Table 5f.

Table 5f –Contemporaneous Emission Increases After Phase II			
Pollutants	Allowed Emission Increases from One Turbine and Emergency Fire Pump Engine, tons/yr	Actual Emission Reductions from Units 1, 2, 3, tons/yr	Contemporaneous Emission Increase, tons/yr
NOx	72.11	32.21	39.90
CO	217.3	268.80	-51.50
VOCs	20.1	15.33	4.77
SOx	5.6	6.15	-0.55
PM10	39	31.49	7.51
PM2.5	39	31.40	7.60
PM	39	31.64	7.36

Rule 20.1(c)(33) – Major Modification

Major modification is defined as a physical or operational change which results in a contemporaneous emissions increase for a pollutant or its precursors for which the District does not attain the federal ambient air quality standards at an existing major stationary source for that pollutant. As the only national ambient air quality standard San Diego County does not attain is the 8-hour ozone standard, only the ozone precursors NOx and VOCs are evaluated to determine whether a major modification occurs. The major modification threshold for both NOx and VOCs is a contemporaneous emission increase of the pollutant equal to or greater than 25 tons per year. The contemporaneous emission increase of NOx resulting from the CECP is 39.9 tons per year (Table 5c), which is higher than the 25 tons per year threshold for a major modification. Therefore, the proposed CECP is a major modification to the facility for NOx. The CECP is not a major modification for VOCs because the FDOC permit conditions limit VOCs increases to less than 25 tons per year.

Rule 20.1(c)(57) PSD Modification and 40 CFR 52.21

A PSD modification is a contemporaneous emission increase occurring at a modified PSD stationary source equal to or greater than the following emission rates:

Pollutant	Emission Rates (tons/yr)
PM	25
PM10	15
PM2.5	10
NO_2	40
VOCs	40
SO_2	40
CO	100
Lead (Pb)	0.6

(All NOx is considered NO_2 for the purpose of PSD determinations).

Without considering the FDOC annual limits, the contemporaneous emission increase of NOx is 43.39 tons per year, which is higher than the 40 tons per year threshold for a PSD modification. However, the Applicant has accepted a limit of 72.11 tons per year of NOx emissions in the FDOC permit to keep the project NOx emissions below the PSD modification threshold. None of the other pollutant contemporaneous emission increases exceed the PSD modification level (see Tables 5b and 5c, there are no lead emissions from the CECP).

Rule 20.3(d)(1)- Best Available Control Technology(BACT)/Lowest Achievable Emission Rate(LAER)

Subsection 20.3(d)(1)(i) of the rule requires that Best Available Control Technology (BACT) be installed on a new or modified emission unit on a pollutant-specific basis if emissions exceed 10 lbs/day or more of PM10, NOx, VOCs or SOx. Subsection 20.3(d)(1)(v) also requires that Lowest Achievable Emission Rate (LAER) be installed for a new emission unit which results in an emission increase which constitutes a major modification. Emergency equipment is exempt from the LAER requirements of 20.3(d)(1)(v).

LAER cannot be less stringent than BACT and is required only for air contaminants and their precursors for which the stationary source is major and for which the District is classified as non-attainment of a national ambient air quality standard. Because the District attains the National Ambient Air Quality Standards (NAAQS) for CO, SO_2, PM2.5 and PM10, LAER does not apply to these pollutants. LAER, however, applies to NOx emissions since the CECP constitutes a major modification for NOx. For the combustion turbines, BACT applies for VOCs, SOx, and PM10 emissions because their emissions are more than 10 pounds per day.

Rule 20.3(d)(1)(vi) also requires that for a new or modified emission unit at a PSD stationary source with an emission increase of one or more air contaminant which constitutes a new PSD stationary source or PSD modification, BACT shall apply for each such air contaminant. Although the contemporaneous emission increase for CO is less than the PSD modification threshold, the emission increase for CO from the CECP itself is larger than the PSD stationary source threshold. Therefore, the CO emissions are also subject to BACT.

In summary, based on emission estimates, LAER is triggered for NOx and, for the combustion turbines, BACT is triggered for CO, VOCs, SOx, and PM10. For the emergency fire pump engine, BACT is triggered only for CO as part of the CECP because the potential to emit VOCs, SOx, and PM10 is less than 10 pounds per day for the emission unit.

<u>Oxides of Nitrogen (NOx)—Combustion Turbines, Normal Operations</u>

The turbine vendor has guaranteed a NOx emission level of 2.0 ppmvd at 15% oxygen at greater than 60% load with the SCR add-on air pollution control system to control NOx installed. The Applicant has proposed a NOx emission limit of 2.0 ppmvd averaged over one hour as BACT and LAER during normal operations.

According to the ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT/LAER for NOx emissions from combined-cycle combustion turbine is either a NOx emission concentration of 2.5 ppmvd based on a one-hour averaging period or 2.0 ppmvd based on a three-hour averaging period, both calculated at 15% oxygen. However ARB is revising its BACT/LAER guidance for power plants to include limits achieved or proposed by more recent projects. The District consulted the BACT / LAER Clearinghouses, other air districts, EPA, and ARB for recent BACT/LAER determinations. A number of combined-cycle power plants of comparable size were permitted with NOx at 2.5 ppmvd or lower, averaged over one hour. The District examined the following projects with NOx emission limits less than 2.5 ppmvd at 15% oxygen:

- The Sithe Mystic Development LLC power plant is permitted by the Massachusetts Department of Environmental Protection and has been in commercial operation since 2002. This plant has been in compliance with a 2 ppmvd NOx limit averaged over one hour, excluding startups and shutdowns, with less than 0.1% of operating time exceeding this standard.

- The Avenal Power Center is proposed to be permitted by the San Joaquin Valley Air Pollution Control District in a Preliminary Determination of Compliance issued on July 11, 2008 [CEC Docket No. 08-AFC-01]. This plant is proposed to be permitted at 2.0 ppmvd of NOx averaged over one hour.

- The Diamond Wanapa, L.P, power plant is permitted by EPA, Region X, at 2 ppmvd of NOx averaged over three hours. This plant has not been constructed yet.

- The El Segundo Power Redevelopment Project is proposed to be permitted by South Coast Air Quality Management District in a Preliminary Determination of Compliance issued on August 22, 2008 [CEC Docket No. 00-AFC-14C (Amendment Proceeding)]. This plant has two rapid response combined-cycle Siemens turbines identical to the combustion turbines proposed for the CECP, and is proposed to be permitted at 2.0 ppmvd of NOx averaged over one hour.

• The Palomar Energy Center in Escondido permitted by the District has been able to comply with 2.0 ppmvd NOx limit averaged over one hour during normal operations, excluding startup and shutdown periods, limited periods of low load operation, rapid transients, and tuning of the combustors and the SCR.

Based on the above information, the District has determined that BACT for NOx should be 2.0 ppmvd at 15% oxygen, averaged over one hour for normal operation with appropriate exclusions to address technical feasibility for startups and shutdowns and other abnormal periods of operation. As defined in Rule 20.1(c)(32), LAER means the most stringent emission limitation, or most effective emission control device or control technique, unless such emission limit , device or technique is not achievable. An emission limit of 2.0 ppmvd NOx at 15% averaged over one hour is considered by the District to be the current most stringent emission limit for larger combined-cycle combustion turbines that is achievable. Therefore, this standard also applies as LAER for NOx for such turbines.

As proposed by the Applicant, the CECP combustion turbines will be equipped with dry ultra low-NOx combustors and a SCR add-on emission control system that in combination are designed to achieve 2.0 ppmvd NOx averaged over one hour. The District is unaware of any demonstrations that alternative technologies for control of NOx such as the XONON™ catalytic combustors or EMx™ (SCONOX) catalyst system can achieve NOx emission levels lower than the combination of dry ultra low-NOx combustors and SCR on large (greater than 50 MW) natural-gas-fired combustion turbines. A continuous emission monitoring system (CEMS) and annual source testing will be used to confirm compliance with this emission limit.

<u>Carbon Monoxide (CO)—Combustion Turbines, Normal Operations</u>

The turbine vendor has guaranteed a CO emission level of 2.0 ppmvd at 15% oxygen at greater than 60% load with the oxidation catalyst add-on air pollution control system to control CO installed. The Applicant has proposed a CO emission limit of 2.0 ppmvd averaged over one hour as BACT and LAER during normal operations.

According to ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT for CO emissions from this equipment is 6.0 ppmvd based on a 3-hr averaging period, calculated at 15 % oxygen. Because the ARB Guidance is being updated, other air districts, EPA, and ARB Clearinghouses, were been consulted for more recent determinations. The District examined the following projects with CO emission limits less than 4.0 ppmvd at 15% oxygen:

- The Sithe Mystic Development LLC power plant in Massachusetts is permitted at 2.0 ppmvd CO averaged over one hour with startups and shutdowns excluded.

- The Avenal Power Center is proposed to be permitted by the San Joaquin Valley Air Pollution Control District in a Preliminary Determination of Compliance issued on July 11, 2008 [CEC Docket No. 08-AFC-01]. This plant is proposed to be permitted at 4.0 ppmvd of CO averaged over three hours.

- The Magnolia Power Project is permitted by the South Coast Air Quality Management District at 2.0 ppmvd CO averaged over one hour. This plant has has been operating since 2005.

- The El Segundo Power Redevelopment Project is proposed to be permitted by South Coast Air Quality Management District in a Preliminary Determination of Compliance issued on August 22, 2008 [CEC Docket No. 00-AFC-14C (Amendment Proceeding)]. This plant has two rapid response combined-cycle Siemens turbines identical to the combustion turbines proposed for the CECP, and is proposed to be permitted at 2.0 ppmvd of CO averaged over one hour.

- The Palomar Energy Center in Escondido has been able to comply with 4.0 ppmvd CO limit averaged over three hours during normal operations, excluding startup and shutdown periods and periods of low-load operations and tuning. District experience based on CEMS data indicates that it likely achieves 2.0 ppmvd averaged over one hour.

Based on the information above, the District has determined a CO limit of 2.0 ppmvd calculated at 15% oxygen averaged over one hour to be BACT for CO for the CECP combustion turbines for normal operation with appropriate exclusion to address technological feasibility for startups and shutdowns and other abnormal periods of operation. To meet this requirement, the Applicant evaluated the use of an oxidation catalyst, which is the only postlcombustion technology currently available to control CO, VOCs, and toxic emissions. This technology is acceptable as BACT for CO. The Applicant will therefore use an oxidation catalyst to meet the BACT level of 2.0 ppmvd at 15 % oxygen on a one-hour average. A CEMs and annual source testing will be used to confirm compliance with this limit.

<u>Volatile Organic Compounds (VOCs)—Combustion Turbines, Normal Operations</u>

The turbine vendor has guaranteed a VOC emission level of 2.0 ppmvd at 15% oxygen at greater than 60% load with the oxidation catalyst add-on air pollution control system, which is the only postcombustion technology currently available to control CO, VOCs, and toxic emissions. The Applicant has proposed a VOC emission limit of 1.5 ppmvd at 15% oxygen averaged over one hour as BACT at greater than 60% load for normal operations. The limit is to be achieved by use of an oxidation catalyst system. This limit is lower than that the Applicant proposed in the PDOC—i.e., 2.0 ppmvd at 15% oxygen.

According to ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT for VOC emissions from this type of equipment is 2.0 ppmvd based on a three-hour averaging period, calculated at 15 % oxygen. Because the ARB Guidance is being updated, other air districts, EPA and ARB Clearinghouses, have been consulted for more recent determinations. For the PDOC, the District examined the following large combined-cycle combustion turbine projects with VOC emission limits of 2.0 ppmvd or less at 15% oxygen:

- The Sithe Mystic Development LLC power plant in Massachusetts was permitted at 1.7 ppmvd of VOCs averaged over one hour. The Sithe Mystic Power Plant combustion turbine is a Mitsubishi 501G turbine. This turbine is considerably larger and a newer generation G-class combustion turbine as compared the Siemens F-class turbine proposed for this project.

- The Magnolia Power Project was permitted by the South Coast Air Quality Management District at 2 ppmvd of VOCs averaged over one hour. This plant has been operating since 2005.

- The Avenal Power Center is proposed to be permitted by the San Joaquin Valley Air Pollution Control District (SJVAPCD) in a Preliminary Determination of Compliance issued on July 11, 2008 [CEC Docket No. 08-AFC-01]. This plant is proposed to be permitted at 1.4 ppmvd of VOCs averaged over three hours. However, SJVAPCD has indicated in communications to the District that the most stringent limit for CTGs larger than 160 MW that are actually operating in the SJVAPCD is 2.0 ppmvd of VOCs averaged over three hours, with clock hours that include a portion of a startup or shutdown period excluded.

- The El Segundo Power Redevelopment Project is proposed to be permitted by South Coast Air Quality Management District in a Preliminary Determination of Compliance issued on August 22, 2008 [CEC Docket No. 00-AFC-14C (Amendment Proceeding)]. This plant has two rapid response combined-cycle Siemens turbines identical to the combustion turbines proposed for the CECP, and is proposed to be permitted at 2.0 ppmvd of VOCs averaged over one hour.

- The Palomar Energy Center in Escondido, California, has been able to comply with 2.0 ppmvd VOC limit averaged over three hours during normal operations, excluding startup and shutdown periods, limited periods of low load operation, and tuning. District experience based on CO CEMS data indicates that it likely achieves less than 2.0 ppmvd averaged over one hour.

For the FDOC, the District examined the following two additional projects with VOC emission limits of 2.0 ppmvd or less at 15% oxygen:

- The Ricmond County Combustion Turbine Facility was issued a final PSD permit by the North Carolina Department of Environment and Natural Resources for two Siemens turbines similar to those proposed for the CECP with a 1.0 ppmvd VOC limit for loads greater than 70% and a 5.0 ppmvd VOC limit for turbine loads between 60% and 70% (excluding startups, shutdowns, and fuel switching). The turbines are permitted for either combined-cycle or simple-cycle operation. This limit is to be verified by a one-time source test on one of the turbines at greater than 75% load. This facility is not required to have an oxidation catalyst. This facility has not been constructed.

- The P.L. Bartow Power Plant was issued a PSD permit by the Florida Department of Environmental Protection with a VOC limit of 1.2 ppmvd (excluding startups, shutdowns, and fuel switching) for four combined-cycle turbines (permitted to operate in simple-cycle mode in rare situations) and one simple-cycle turbine using Siemens turbines similar to those proposed for the CECP. This facility is not required to have an oxidation catalyst although provisions were made during construction so one could be installed if necessary. The limit has initial compliance as been verified by one-time source tests at 100% load for four of the combined-cycle turbines and 55% load for three of those units in 2009 (the District has not obtained the other source test results). However, the units were not tested at 100% load with steam augmentation, which can increase CO and VOC emissions.

Although the Florida turbines did comply with the 1.2 ppmvd emission limit at low loads, they are not expected to operate at low loads, so the practical affect of the limit at loads less than 70% is unclear. In fact, the turbines are prohibited from operating at less than 70% load in simple-cycle mode by permit conditions (except for startups, shutdowns, tuning, and fuel switching). In combined cycle mode, they are expected to operate as base-loaded units which, unlike the CECP, are expected to typically operate near 100% load as much as possible.

No further periodic verification of compliance with the VOC limit is required for the Florida turbines by the permit. The permit notes state that compliance with the CO emission limit (4.1 ppmvd) will be used as an indicator of low VOC emissions.

Neither the Florida nor North Carolina project require periodic source testing to verify the VOC limit is achieved continuously. While the FDOC permit conditions for the CECP require that the VOC limit be verified by periodic source testing and by monitoring of CO emissions on a hourly basis as a surrogate for VOC emissions (see below) over the life to the turbine. Using CO emission levels as surrogate on an hourly basis is a more robust method of monitoring VOC emissions than an initial source test and CO compliance with a CO limit. An examination of the summary source test results for the Florida turbines indicates that, based on the VOC/CO ratio at high load, the VOC concentration could easily exceed the 1.2 ppmvd limit while the CO concentration remained below 2 ppmvd and in compliance with the 4.1 ppmvd limit for those turbines.

Since the Florida and North Carolina limits have not been verified as achievable over a long period of time and have not been verified with steam augmentation the District does not consider them achieved in practice for the type of turbine and operations proposed for the CECP. Moreover, a catalytic oxidation system designed to achieve 1.5 ppmvd at 60% load should be designed for at least a 70% VOC reduction at that load level since manufacturer specifications indicate uncontrolled VOC emissions can be as high 5 ppmvd at that load. The use of a properly designed oxidation catalyst translates into lower VOC emissions at all loads and at all levels of VOC concentration in the turbine exhaust.

Based on the above information and considerations, the District has determined that BACT for the CECP combustion turbines is a properly designed oxidation catalyst combined with a 1.5 ppmvd VOC limit for turbine loads greater than 60%, measured as methane at 15% O_2 over a one-hour averaging period for normal operation with appropriate exclusions to address technologically feasibility for startups and shutdowns and other abnormal periods of operation.

An initial source test will be used to confirm compliance with these limits. Additionally, the source test data will be used to establish a correlation between CO emissions and VOC emissions to provide an accurate indicator of continued compliance with these limits using the CEMS data for CO on a one-hour basis. Compliance will be determined based on both source test data and a surrogate relationship with CO because CEMS technology is not yet available for VOCs.

Startups and Shutdowns—Combustion Turbines, NOx, CO, and VOCs

Startups are limited to 60 minutes and shutdowns to 30 minutes (an additional 5 minutes are allowed to purge emissions from the stack). These times are consistent with, or more stringent than the recently issued PDOC by the SCAQMD for an identical combined-cycle turbine for the El Segundo Power Redevelopment Project (ESPRP) as recently amended [CEC Docket No. 00-AFC-14C (Amendment Proceeding)]. The expected duration of the turbine startups and shutdowns are 22 minutes and 7 minutes, respectively. The additional time is allowed to address contingencies during startups and shutdowns.

Emissions during startup and shutdown are further controlled by setting mass emission limits per startup and shutdown event (excluding the commissioning period). The mass emission limits are based on manufacturer emission estimates for the expected startup or shutdown durations and maximum emissions during the remainder of the time with an adjustment factor of two for NOx and CO, as proposed by the Applicant to allow for increased emissions during the potential rapid transients during these operations. No adjustment factor is used for VOC emissions, also as proposed by the Applicant. For example, for a 60-minute startup, total allowed emissions for NOx are:

Emissions = 2 x (25 lb for the 22 minute startup + (38/60) x 15.1 lbs/hr for normal operations)

= 69.2 lbs

and, for a 30-minute shutdown, total allowed emissions for VOCs are:

Emissions = 4.7 lb for the 7 minute shutdown + (23/60) x 5.3 lbs/hr for normal operations

= 6.22 lbs

Table 6a presents the mass emissions limits during startup and shutdown

Table 6a – Emission Limits During Startup and Shutdown – SCR to Operate as Soon as Feasible		
Pollutants	Startup Emissions, pounds per event	Shutdown Emissions, pounds per event
NOx	69.2	25.7
CO	545	277
VOCs	15.5	6.22

An additional requirement that applies during startups and shutdowns (and all other times the combustion turbine is operating with an SCR system) is that the SCR be in full operation as soon as its reaches its minimum operating temperature to control NOx to the maximum extent feasible. The minimum temperature is set at 450 degrees Fahrenheit in the FDOC permit conditions based on the minimum operating temperature provided by the manufacturer for the similar SCR associated with the El Segundo Power Redevelopment Project.

The District has determined that the above requirements represent BACT for NOx, CO, and VOCs and LAER, for NOx only, specifically applicable to the CECP during startups and shutdowns of the combustion turbines.

Abnormal Events—Combustion Turbines, NOx, CO, and VOCs

Modern combustion turbines with ultra low NOx combustors normally operate under extremely lean conditions (low fuel to air ratio) where most of the fuel and air are premixed prior to combustion to achieve low NOx, CO, and VOC emissions (lean premix combustion). The operating point is close to the fuel to air ratio where combustion becomes unstable because of the low combustion temperature. To prevent combustion instability, which may result in a turbine trip (unplanned shutdown) and the resulting expense and increased emissions from a unplanned startup, automatic control systems may increase the fuel to air ratio under some abnormal operating conditions. Furthermore, at low loads the fuel may not be premixed with air (diffusion flame mode) to maintain combustion stability. In both these situations, the NOx, CO, and VOC emissions can be much higher than in the lean premix combustion mode. It is, therefore, not technologically feasible, to achieve the BACT emission levels applicable to normal operations in such situations.

Startups and shutdowns are abnormal operating conditions that are discussed above. The Applicant has identified transient events (excluding startups and shutdowns) as another abnormal operating condition. Other abnormal operating conditions that, in the District's experience, may occur with large combined-cycle combustion turbines are low-load operation (excluding startups and shutdowns) and tuning of the turbine combustors or emission control systems to achieve the most efficient operation and low emission rates.

Tuning of the combustion-turbine system may be done for many reasons. Tuning may be done to ensure continued compliance with applicable permit limits. It may also be done to for reasons not directly related to compliance with permit limits. For example, the facility may wish to tune the SCR ammonia injection grid system to reduce ammonia usage, with obvious air quality benefits, even though immediate emission limit compliance or operational safety is not in jeopardy. The facility may also wish to improve the turbine combustor efficiency and thereby reduce greenhouse gas emissions, again without any emission limit compliance or operational safety concerns.

Low-load operation can occur when the turbine's automatic control system senses a possible combustion or other equipment problem and automatically reduces the turbine load to prevent an immediate combustion turbine trip (unplanned shutdown). In most cases, the problem is resolved without shutting down the turbine, which avoids the emissions and cost of a restart.

Based on information supplied by the Applicant and the District's experience with ongoing operations at a large combined-cycle power plant, the District has determined that following represent BACT for NOx, CO, and VOCs and LAER for NOx during specified abnormal events:

- Tuning events are not to exceed 720 minutes in a calendar day nor exceed 40 hours in a calendar year for each turbine.

- The BACT emission limits for normal operations with a three-hour-averaging time instead of a one-hour-averaging time are applicable for any hour in which the change in gross electrical output produced by the combustion turbine exceeds 50 MW per minute for one minute or longer.

- Periods of operation at low load are not to exceed 130 minutes in any calendar day nor an aggregate of 780 minutes in any calendar year.

For NOx, emission limits of 12.6 ppmvd averaged and 42 ppmvd averaged over one hour, which correspond to District Rules 69.3.1 and 69.3 standards, respectively, remain in effect during all abnormal periods. The District has proposed amending Rule 69.3.1 to exclude low-load periods. However, if this amendment is adopted, the Rule 69.3 limit would still remain in effect. The District's criteria for a transient events and BACT levels have been acceptable to another large combined-cycle facility.

<u>PM10 and SOx—Combustion Turbines</u>

From the ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT for this equipment is the use of natural gas that contains less than 1 grain of sulfur compounds per 100 standard cubic feet of natural gas. Public Utility Commission (PUC) quality natural gas sold in San Diego County is required to meet a maximum sulfur content limit of 0.75 grains of sulfur compounds per 100 standard cubic feet of natural gas. Therefore, use of PUC quality natural gas meeting this 0.75 grains limit is recommended as BACT. In actuality, the natural gas in the local gas distribution system averages well under 0.75 grains per 100 standard cubic feet of gas. The Applicant will be required to maintain documents showing the sulfur content of natural gas used. Any alternative supplies of natural gas must meet this sulfur content limit.

BACT—Emergency Fire Pump Engine

When technologically feasible, BACT for emergency engines is to use an engine fueled with natural gas. However, emergency fire pumps require an independent source of fuel for reliable operation in emergency situations in which the natural gas supply might be interrupted. In addition, add-on emission control systems are not technologically feasible as they may compromise the reliability of the fire pump. Therefore, the District has concluded that BACT for the emergency fire pump engine is an engine certified to the most stringent federal emission standard for fire pump engines (i.e., a 2009 or later model year engine). The fire pump engine must also comply with the requirements of Section 93115 et. seq. of Title 17 of the California Codes of Regulations (CCR)

Rule 20.3(d)(2) – Air Quality Impact Analysis (AQIA)

This subsection of Rule 20.3 requires that a project resulting in an emission increase equal to or greater than the AQIA Thresholds shall demonstrate through an AQIA that the project will not cause or contribute to a violation of a state or national ambient air quality standard. For the CECP, an Air Quality Impact Analysis (AQIA) was performed to determine if the proposed project by itself contributes to an exceedance of the National Ambient Air Quality Standards or the State Ambient Air Quality Standards. The modeling was done under expected worst-case hourly and annual emission rates during commissioning, startup and shutdown, and normal operations. For the FDOC, no additional modeling was performed, but some of the ambient background values used in the analysis were adjusted where necessary. Additionally, the PM2.5 impacts were reanalyzed in light of recent (post-PDOC) EPA actions.

The analysis shows no violation of any Ambient Air Quality Standard. The analysis can be reviewed in more detailed the Appendix A of this determination. The FDOC permit conditions contain hourly and annual emission limits that are applicable at all times to ensure that the project will not cause or contribute to a violation of any National Ambient Air Quality Standard or California Ambient Air Quality Standard.

Rule 20.3 (d)(3) -Prevention of Significant Deterioration (PSD)

This subsection requires that a PSD evaluation be performed for any new PSD stationary source (source that has an aggregate potential to emit of one or more air contaminants in amount equal to or greater than the PSD thresholds) and to any PSD modification (contemporaneous emission increase occurring at a modified PSD stationary source equal to or greater than the PSD modification thresholds), for those air contaminants for which the District is classified as attainment or unclassified with respect to a national ambient air quality standard. The Encina Power Plant is an existing PSD stationary source. Therefore, only the PSD modification threshold is applicable to determining whether a PSD evaluation needs to be performed. The Applicant has accepted an annual limit of 72.11 tons per year of NOx emissions to keep the project NOx emissions below the PSD modification threshold. Since the annual limit suffices to avoid the PSD modification threshold and NOx emissions are monitored with CEMS, no limits on hours of normal operations or startup and shutdown are necessary. As shown in Tables 5b and 5c, the contemporaneous emissions increase for all other pollutants do not exceed the applicable PSD modification thresholds after completion of the project. In addition, for Phase I of the project the Applicant has accepted permit limits, as necessary, to limit contemporaneous emission increases to less than all PSD modification thresholds (see Tables 5d and 5e). Therefore, the CECP is not subject to the requirements 0f 20.3(d)(3).

Rule 20.3(d)(4) – Public Notice and Comment

For any project that is subject to the AQIA requirements of Rule 20.3(d)(2), these provisions require tha the District publish a notice of the proposed action in at least one newspaper of general circulation in San Diego County as well as send notices and specified documents to the EPA and ARB. Because the project is not subject to Rule 20.3(d)(3) the additional notification requirements of Rule 20.3(d)(3)(iii) are not applicable. Notice of proposed installation of the CECP was published in the San Diego Daily Transcript and mailed to EPA and ARB air districts for a 30-day comment period in accordance with Rule 20.3(d)(4).

Rule 20.3(d)(4)(i) requires that the District consider all comments received. The District considered all comments received before taking this final action.

Rule 20.3(d)(5)-Emission Offsets

This provision requires that emission offsets be provided for projects that result in a contemporaneous emission increase of any federal nonattainment criteria pollutant or its precursors which exceed new major source or major modification thresholds. The District is a federal nonattainment area only for ozone. Therefore, offsets are potentially only required for NOx and VOC emissions, as ozone precursors. For the CECP, VOC annual emission increases are limited to below the major modification thresholds by the FDOC permit conditions without consideration of actual emission reductions. Therefore, offsets are only required for NOx emissions. The maximum contemporaneous emission increase of NOx is 39.9 tons per year for this project. An offset ratio of 1.2 to 1 is required [Rule 20.3(d)(8)(i)(B)], so a total of 47.88 tons per year of NOx emission offsets will be required. The offsets must be surrendered to the District prior to the initial startup of the equipment for which they are required [Rule 20.1(d)(5)(iii)]. Offsets may be actual emission reductions, stationary source Class A emission reduction credits (ERCs) issued under District Rules 26.0-26.10, or mobile source emission reduction credits (MERCs) issued under District Rule 27 (if approved by ARB and EPA.). The Applicant has agreed to surrender ERCs sufficient to provide all the required offsets for the project prior to the initial operation of first turbine.

Cabrillo II, LLC, a wholly owned subsidiary of NRG Energy, Inc., the Applicant's parent company, currently owns Emission Reduction Credits (ERCs) representing 37.6 tons per year of NOx emission offsets and the Applicant has entered a contractual option to purchase up to 24 tons of VOC ERCs to provide the remaining required offsets. Under District Rule 20.1 (d)(v)(6), the VOC ERCs are discounted by a ratio of 2 to 1 when used to provide NOx offsets. The ERCs to be used as offsets are listed in Appendix D.

Rule 20.3(e)(1) – Compliance Certification

This rule requires that, prior to receiving an Authority to Construct (or Final Determination of Compliance), an applicant for any new or modified stationary source required to satisfy the LAER provisions of Rule 20.3(d)(1) or the major source offset requirement of Rule 20.3(d)(8) shall certify that all major sources operated by the applicant in the state are in compliance with all applicable emissions limitations and standards under the federal Clean Air Act. The Applicant is an indirect wholly owned subsidiary of NRG Energy, Inc., which also operates the Encina Power Station, which is a major stationary source located in San Diego County, and on whose property the CECP will be located. The Encina Power Station operation has been regulated by the San Diego Air Pollution Control District under permits to operate issued for its five boilers and one gas turbine. Besides the Encina Power Station, NRG Energy owns other potential major stationary sources in the state including the El Segundo Generating Station in El Segundo California and the Long Beach Generating Station in Long Beach California. The required compliance certifications for all major sources in the state owned by NRG Energy or its subsidiaries, Inc. have been submitted to the District.

Rule 20.3(e)(2) – Alternative Siting and Alternatives Analysis

The Applicant has provided an analysis of various alternatives to the project. This analysis included a No Project alternative, alternative sites, and alternative technologies. Since all of San Diego County is currently classified as non-attainment for ozone, an alternative location within San Diego would not avoid the project being located in a non-attainment area.

Rule 20.5 – Power Plants

This rule requires that the District submit Preliminary and Final Determinations of Compliance reports to the California Energy Commission (CEC). The Final Determination of Compliance is equivalent to a District Authority to Construct. This Preliminary Determination of Compliance was submitted to the CEC on November 20, 2008. This Final Determination of Compliance will be submitted to the CEC.

DISTRICT PROHIBITORY RULES

Rule 50 – Visible Emissions

This rule limits air contaminants emissions into the atmosphere of shade darker than Ringlemann 1 (20% opacity) to not more than an aggregate of three minutes in any consecutive sixty-minute period.

Based on the proposed equipment and the type of fuel to be used (natural gas), no visible emissions at or above this level are expected during operation of the power plant.

Rule 51 – Nuisance

This rule prohibits the discharge of air contaminants that cause or have a tendency to cause injury, nuisance, annoyance to people and/or the public or damage to any business or property.

No nuisance or complaints are expected from this type of equipment.

Rule 53 – Specific Air Contaminants

This rule limits emissions of sulfur compounds (calculated as SO_2) to less than or equal to 0.05% (500 ppm) by volume, on a dry basis. The rule also limits particulate matter emissions from gaseous fuel combustion to less than or equal 0.1 grains per dry standard cubic foot of exhaust calculated at 12% CO_2.

Sulfur Compounds

The Applicant proposes to use Public Utilities Commission (PUC) quality natural gas sold in San Diego County. Because of the low sulfur content of the fuel, the plant is expected to comply with the sulfur emission requirements of Rule 53. The fuel is expected to have a sulfur content less than 0.75 grains per 100 dry standard cubic foot (gr/100 dscf).
Using an F-Factor of 8710 standard cubic feet of exhaust gas per million Btu of heat input for natural gas combustion at 0% O_2 in the exhaust, assuming all sulfur in the fuel is converted into SO_2, the concentration by volume of SO_2 in the exhaust gas is:

SO_2 concentration = (0.75 grain /100 scf fuel) x (1lb SO_2 / 7000 grain) x (385 scf SO_2 / 64 lb SO_2) x (1 scf fuel / 1015 x 10^{-6} MMBtu) x (1MMBtu / 8710 dscf of exhaust) x (10^6) = 0.72 ppm SO_2 by volume.

This is well below the Rule 53 limit of 500 ppm SO_2 by volume. Therefore, the project is expected to comply with this rule.

Particulates

Using an F-Factor of 198.025 standard cubic feet of exhaust per pound of natural gas combusted @ 12% $CO_{2,}$ a maximum natural gas usage of 91,454 lbs /hr, and an estimated maximum particulate matter emission rate of 9.5 lbs/hr, combustion particulate at maximum load are estimated to be:

Grain loading = [(9.5 lbs/hr)(7,000 gr/lb)] / (198.025 scf/lb fuel)(91,454 lbs fuel/hr)) = 0.004 gr/dscf

This is well below the Rule 53 emission limit of 0.1 gr/dscf. Therefore the plant is expected comply with this rule.

Rule 68 –Oxides of Nitrogen from Fuel Burning Equipment

This rule limits NOx emissions from any natural gas fueled combustion equipment to less than 125 ppmvd calculated at 3% oxygen on a dry basis. However, this equipment is subject to the more stringent requirements of Rule 69.3 and Rule 69.3.1 and is exempt from Rule 68.

Rule 69.3-Stationary Gas Turbines – Reasonably Available Control Technology

This rule limits NOx emissions from combustion turbines fueled with natural gas greater than 0.3 MW to 42 ppmvd at 15% oxygen when fired on natural gas. Equipment is exempt from the standards during 120 minute startup and shutdown periods.

The combustion turbines for this project will be equipped with dry ultra low NOx combustors and SCR controls for NOx. Proposed permit conditions limit NOx emissions to 2.0 ppmvd during normal operations, which is far below the 42 ppmvd rule standard. Maximum durations of startups and shutdowns (60 minutes for startup and 30 minutes for shutdown) are shorter than Rule 69.3 requirements. However, commissioning, low-load operation, tuning, and transient periods are still subject to the rule standards. The facility permit will contain conditions to limit emissions below the emissions levels specified in Rule 69.3 (excluding startups and shutdown as defined in Rule 69.3). A CEMS will monitor emissions during combustion turbine operations.

Rule 69.3.1 – Stationary Gas Turbines – Best Available Retrofit Control Technology

This rule limits NOx emissions from combustion turbines greater than 10 MW to 15x(E/25) ppmvd when operating uncontrolled and 9 x (E/25) ppm at 15% oxygen when operating with add-on emission controls and averaged over a one-hour period, where E is the thermal efficiency of the unit. The rule also specifies monitoring and record keeping requirements. Startups, shutdowns, and fuel changes are defined by the rule and excluded from compliance with these limits. Equipment is exempt from the standards during 120 minute startup and shutdown periods.

The thermal efficiency for each turbine, as stated by the Applicant, is 36.5 %. Therefore the maximum allowable uncontrolled NOx concentration is 21.9 ppmvd based on a 1-hour averaging period at 15% oxygen and the maximum allowable controlled NOx concentration is 12.6 ppmvd. The uncontrolled concentration limit would only be applicable prior to installation of the SCR system.

The combustion turbines for this project will be equipped with dry ultra low NOx combustors and SCR controls for NOx. The FDOC permit conditions limit NOx emissions to 2.0 ppmvd during normal operations, which is far below the 12.6 ppmvd rule standard. Maximum durations of startups and shutdowns (60 minutes for startup and 30 minutes for shutdown) are shorter than Rule 69.3.1 requirements. However, commissioning, low-load operation, tuning, and transient periods are still subject to the rule standards. The facility permit will contain conditions to limit emissions below the emissions levels specified in Rule 69.3.1 (excluding startups and shutdown as defined in Rule 69.3.1). A CEMS will monitor emissions during combustion turbine operations. A CEMS will monitor emissions during combustion turbine operations.

Rule 69.4 – Stationary Reciprocating Internal Combustion Engines – Reasonably Available Control Technology

This rule applies to stationary internal combustion engines with brake horsepower rating of 50 or greater and located at a stationary source with potential to emit of 50 tons per year or more of NOx. Since the proposed emergency fire pump engine is subject to Rule 69.4.1, which contains more stringent standards, compliance with Rule 69.4.1 will serve for compliance with Rule 69.4.

Rule 69.4.1 – Stationary Reciprocating Internal combustion Engines – Best Available Retrofit Control Technologies.

Rule 69.4.1(d)(1) requires the engine to meet the NOx emission standard of 6.9 grams per brake horsepower hour (g/bhp-hr). This preliminarily proposed engine is an EPA certified engine with NOx emission at 3.92 g/bhp-hr. In addition, the FDOC permit conditions will require the engine to meet the more stringent EPA certification requirements for model year 2009 and later engines. Therefore, the engine is in compliance with this requirement.

Rule 69.4.1(d)(2) requires the engine to meet CO emission standard of 4500 ppmvd at 15% oxygen. This engine is in compliance with this requirement, with a CO emission level of 61.2 ppmvd at 15% oxygen.

Rule 69.4.1(d)(4) requires the engine to use only California Diesel fuel. The use of CARB diesel is specified in the FDOC permit conditions.

Rule 69.4.1(e)(3) requires installation of a non-resettable totalizing meter or a non-resettable hour meter. The proposed engine has an hour meter.

Rule 69.4.1 requires the engine operator to conduct periodic maintenance of the engine and its control system in accordance with a procedure recommended by the manufacturer or approved by the District. Compliance with this requirement is verified through recordkeeping.

Rule 69.4.1(g)(1)(v), (vi) requires the engine operator to keep records of California Diesel fuel certification and engine maintenance procedure. Compliance with this requirement is verified through recordkeeping.

Rule 69.4.1(g)(2) requires the engine operator to maintain an operating log of the dates and times of engine operation, of the total cumulative hours of operation per calendar year, and of engine periodic maintenance. Compliance with this requirement is verified through recordkeeping.

Rule 69.4.1(g)(6) requires all records to be kept on site for at least three years and made available to the District upon request. The FDOC permit conditions require records to be kept five years.

Rule 69.4.1(i)(1) exempts emergency standby engines from periodic source testing.

Rule 1200 – Toxic Air Contaminants

Rule 1200 New Source Review for Toxic Air Contaminants requires that a Health Risk Assessment (HRA) be performed if the potential to emit toxic air contaminants will increase. A detailed HRA is necessary if toxics emissions exceed District de minimis levels. Toxic Best Available Control Technology (TBACT) must be installed if the HRA shows a cancer risk greater than one in a million at a receptor where a person could be reasonably anticipated to be exposed. The cancer risk is based on a 70-year exposure for a residence and a shorter exposure time for occupational workers. Additional requirements apply if the cancer risk is expected to exceed ten in a million.

An HRA, which was reviewed by the District, was performed using EPA AP-42 emission factors and California Air Toxics Emission Factors (CATEF) for toxic air contaminant emissions from the project for normal operations. The emission increases from the operation of the two combustion turbines and the emergency fire pump engines were considered. No emission decreases from the existing facility were accounted for in the assessment. In addition, potential acute health impacts during startup shutdown and commissioning operations and the contributions of those operations to chronic impacts and cancer risk were examined using emission factors based on a recent source test of a combined-cycle power plant during the first hour of a cold start. The HRA performed shows that the incremental cancer risk is 0.47 in a million for exposed residents and 0.27 for exposed workers if the number of startups per turbine is limited to 1460 per year. The FDOC permit conditions limit the number of startups for each turbine to 1460 per year. The acute and chronic incremental health impacts measured by the Health Hazard Index (HHI) are also all less than 1.0 at the point of maximum impact (0.01, 0.12, and 0.16 for the chronic, 8-hour, and acute HHIs, respectively) and, therefore, meet Rule 1200 requirements. Although TBACT is not required since the maximum cancer risk is less than one in a million, the oxidation catalyst installed as BACT for CO and VOC emissions also significantly reduces toxic air contaminant emissions and would be considered TBACT for this project—if TBACT had been required. The health risk analysis of this project is further discussed in Appendix B of this document.

Regulation XIV – Title V Operating Permits

The CECP is co-located with the Encina Power Station and under common control ownership. The Encina Power Station currently has a Title V Operating Permit. The Applicant has submitted an application to modify this Title V Operating Permit to include the CECP project.

STATE REGULATIONS IMPLEMENTED BY THE DISTRICT

Health and Safety Code §42301.6

This section of the state Health and Safety Code requires the District to notify parents of students at a school if a new source of air pollution is within a 1000 feet of the boundary of that school. The District has determined that the CECP is not within 1000 feet of any school boundary.

Title 17 of the California Codes of Regulations (CCR) §93115—Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines

The emergency diesel fire pump engine is subject to the Title 17 of the California Codes of Regulations (CCR) §93115—Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines.

Section 93115.5(a)(1) requires that by January 1, 2006, no owner or operator of a new stationary CI engine or an in-use prime stationary diesel-fueled CI engine shall fuel the engine with any fuel unless the fuel is one of the following: CARB Diesel Fuel; or an alternative diesel fuel that meets the requirements of the Verification Procedure; or an alternative fuel; or CARB Diesel Fuel used with fuel additives that meets the requirements of the Verification Procedure; or any combination of the above fuels. The FDOC permit conditions required the use of only CARB Diesel Fuel.

Section 93115.6(a)(1) requires that no owner or operator shall operate a new stationary emergency standby diesel-fueled CI engine for nonemergency use, including maintenance and testing, during the following periods: whenever there is a school sponsored activity, if the engine is located on school grounds; and between 7:30 am and 3:30 pm on days when school is in session if the engine is located within 500 feet of school grounds. This requirement does not apply if the engine emits no more than 0.01 g/bhp-hr of diesel PM. Compliance is required through the FDOC permit conditions.

Section 93115.6(a)(3)(A)(1) requires that new stationary emergency standby diesel-fueled engines (>50 bhp) shall emit diesel PM at a rate less than or equal to 0.15 g/bhp-hr; or meet the current model year PM standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423), whichever is more stringent; and not operate more than 50 hours per year for maintenance and testing purposes. The proposed engine PM emission rate is 0.09 g/bhp-hr. The engine is limited to 50 hours per year for testing and maintenance operation by the FDOC permit conditions.

Section 93115.6(a)(3)(B) requires that new stationary emergency standby diesel-fueled engines (>50 bhp) meet the HC, NOx, NMHC+NOx, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13, CCR, Section 2423). The preliminarily proposed engine meets the Tier 2 HC, NOx, NMHC + NOx and CO standards for off-road engine of the 2005 model year.

Section 93115.10(a) requires each owner or operator of new and in-use stationary CI engines, including non-diesel-fueled CI engines, to submit to the District APCO information on owner/operator contact information; engine information; fuel used; operation information; receptor information; and whether the engine is included in an existing AB2588 emission inventory. The District may exempt the owner or operator from providing all or part of this information if there is a current record of the information in the owner or operator's permit to operate, permit application, or District records. This information has been provided by the Applicant in the application submitted for the CECP.

Section 93115.10(e) requires that a non-resettable hour meter be installed upon engine at installation on all engines subject to all or part of the emission standards requirements. The engine will be required to have an hour meter by the FDOC permit conditions.

Section 93115.10(g)(1) requires each owner or operator of an emergency standby diesel-fueled CI engine to keep records and prepare a monthly summary that lists and documents the nature of use for emergency use hours, maintenance and testing hours, initial start-up testing hours, retention of fuel purchase records for CARB diesel fuel. Compliance is required through the FDOC permit conditions.

Section 93115.10(g)(2) requires all records to be retained for a minimum of 36 months. Records for the prior 24 months shall be retained on-site, and made immediately available to District staff upon request. Records for the prior 25 to 36 months shall be made available to District staff within 5 working days from request. Compliance is required through the FDOC permit conditions.

Section 93115.13 requires that upon approval by the District APCO, the following sources of data may be used in whole or in part to meet the emission data requirements:

A. Off road engine certification test data for the stationary diesel-fueled CI engine.
B. Engine manufacturer test data.
C. Emission test data from a similar engine, or

D. Emission test data used in meeting the requirements of the Verification Procedure for the emission control strategy implemented.

Engine manufacturer emission data were used to verify compliance with emission standard requirements.

NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)

The Encina Power Station is an existing major source of hazardous air pollutants (HAPs) based on the potential to emit hexane over the 10 ton per year major source threshold for a single HAP. Estimated actual emissions of hexane, calculated using an EPA (AP-42) emission factor, were about 13.5 tons per year in 2006. Therefore, equipment at the Encina Power Station are subject to NESHAPS applicable to major stationary sources of HAPs.

40 CFR Part 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

This subpart establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emissions and operating limitations. However, except for Initial Notification requirements [40 CFR §63.6145] EPA has stayed the applicability of this regulation for gas-fired combustion turbines [40 CFR §63.6905(d)].

40 CFR Part 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Compression Ignition Internal Combustion Engines

This subpart for stationary compression ignition internal combustion engines requires [40 CFR §63.6590(c)] engines rated less than 500 brake horsepower located at major sources of HAP emissions (and also all engines at nonmajor sources of HAPs) to comply with the requirements in 40 CFR Part 60 Subpart IIII— Standards of Performance for Stationary Compression Ignition Internal Combustion (CIIC) Engines. There are no other requirements applicable to such engines. Proposed permit conditions require compliance with Subpart IIII.

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR Part 60- Subpart KKKK- National Standards of Performance for New Stationary Combustion Turbines.

This new source performance standard requires stationary combustion turbines with a heat input equal to or greater than 10 MMBtu/hour based on the high heating value of the fuel to comply with NOx and SOx emission standards.

Section 60.4320 requires new combined-cycle combustion turbines firing natural gas with a rated heat input greater than 850 MMBtu/hour to comply with a NOx standard of 15 ppmvd at 15% O_2 averaged over each 30 operating days, or alternatively, a standard of 0.42 pounds per megawatt hour (lb/MWh) during normal operations. During periods of less than 75% load the corresponding standards are 96 ppmvd and 4.7 lb/MWh. The actual limit during any 30-day period is an average of the normal and less than 75% standards.

With SCR as postcombustion emission control, NOx emissions from this combustion turbine are controlled to 2.0 ppm at 15% O_2 during normal operation. Information submitted as part of the proposed City of Vernon Power Plant (06-AFC-4, Table 8.1B-2) indicates that the expected typical maximum NOx level for this model turbine is 50 ppm at less than 50% load (as occurs during startup and shutdown). Assuming NOx emission concentration during startup and shut down is 50 ppm at 15% O_2, the NOx emission concentration averaged over a 30-day period that has 50 hours of startup, 25 hours of shutdown and 250 hours of normal operation is:

> NOx concentration = [50 ppm x (50 startup hours)] x [50 ppm x (25 shutdown hours)] + (2 ppm x 250 normal operation hours)] / (325 hours) = 13 ppm

Therefore, the turbine is expected to comply with the NOx emission standard of this subpart. Compliance is required through the FDOC permit conditions.

Section 60.4330 prohibits sulfur dioxide emissions from combustion turbine in excess of 0.90 lbs/MW-hour gross output or 0.060 lbs/MMBtu heat input. SO_2 emission from the combustion turbines of this project is 0.002 lbs/MMBtu.

$$SO_2 \text{ emission rates} = (4.4 \text{ lbs/hr}) \times (1 \text{ hour/ } 1947 \text{ MMBtu}) = 0.002 \text{ lbs/MMBtu}$$

Therefore, the turbine is in compliance with the SO_2 limit requirement.

Section 60.4340(b) requires turbines not using water injection or steam injection to install, calibrate, maintain and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor and a diluent gas (oxygen) or carbon dioxide monitor to determine the hourly NOx emission rate in ppmvd or lb/MWh. Turbines complying with concentration limit based standards must install calibrate, maintain and operate a fuel flow meter to measure heat input. Turbines complying with output-based standards must install, calibrate, maintain and operate a watt meter to measure the gross electrical output in megawatt-hours. This combustion turbine will be equipped with a CEMS to monitor NOx and CO emissions in parts per million and oxygen content in the exhaust gas. In addition, the gross electrical output in MWh will also be monitored.

Section 60.4345 requires the CEMS to be installed and certified according to Performance Specification 2 in Appendix B to this part, or according to Appendix A of part 75 of this chapter, and each fuel meter and watt meter shall be installed, calibrated, maintained and operated according to the manufacturer’s instructions. The turbine operator must develop and keep on site a QA plan for all continuous monitoring equipment. The CEMS for this combustion turbine will be required to go through Relative Accuracy Test Audit (RATA) and all other required certification tests in accordance with 40 CFR Part 75 Appendix A and B. The FDOC permit requires continuous monitoring equipment meeting these requirements to be installed, calibrated, and maintained.

Section 60.4350 requires turbine operator to use data from the CEMS to identify excess emissions in accordance with specific procedures. These requirements are included in the FDOC permit conditions.

Section 60.4365 exempts the requirement to monitor total sulfur content of the fuel if it can be demonstrated through a valid purchase contract , tariff sheet or transportation contract for the fuel that total sulfur content of natural gas used is 20 grains of sulfur or less per 100 standard cubic feet. Sulfur content of natural gas fuel used in this turbine is 0.75 grains per 100 cubic feet of gas or less. Quarterly records of natural gas sulfur content are to be kept on site to satisfy this requirement.

Section 60.4375 requires submittal of reports of excess emissions and monitor downtime for all periods of unit operation, including startup, shutdown and malfunction. The FDOC permit includes a condition to satisfy these requirements. Annual source tests are not required pursuant to Subpart KKKK for combustion turbine equipment with CEMS. Since this combustion turbine is subject to a NOx limit that is seven times more stringent than the NOx limit of this NSPS, excess emissions are not expected to occur. In addition, reports on the CEMS system are to be submitted in accordance with Rule 19.2 requirements and CEMS protocol approved by the District and excess emissions and monitoring reports are required by the FDOC permit conditions..

Section 60.4400 requires that an initial performance test and annual NOx performance test be conducted in accordance with certain requirements. Annual source tests are not required pursuant to Subpart KKKK for combustion turbine equipment with CEMS. This combustion turbine is required to be source tested initially to demonstrate compliance with NOx, CO, VOC, and ammonia emission standards. The source tests are to be conducted in accordance with the applicable EPA test methods and applicable requirements of 40 CFR 75 Appendix B. The FDOC permit contains conditions satisfying these requirements of Subpart KKKK.

40 CFR Part 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion (CIIC) Engines

Section 60.4205 requires owners and operators of fire pump engines rated between 175 bhp and 300 bhp and of model year 2008 and earlier to comply with NOx + HC emission limit of 7.8 grams per brake horsepower hour (g/bhp-hr), CO limit of 2.6 g/bhp-hr and a PM limit of 0.4 g/bhp-hr. Fire pump engines of model year 2009 and after must comply with NOx + HC emission limit of 3 g/bhp and PM emission limit of 0.15 g/bhp-hr. Although the engine preliminarily proposed by the Applicant would not comply with model year 2009 standards, the Applicant has committed to install a compliant engine and the FDOC permit conditions require compliance with the standards of Subpart IIII for model year 2009 and later engines.

Section 60.4207 requires that beginning October 1, 2007, owners and operators of station CIIC engines subject to Subpart IIII to use diesel fuel with a maximum sulfur content of 500 ppm per gallon; and beginning October 1, 2010, to use diesel fuel with a maximum fuel content of 15 ppm per gallon. This engine is required to use CARB diesel fuel, which complies with this requirement.

Section 60.4209 requires that owners or operators of engines subject to Subpart IIII to install a non-resettable hour meter prior to startup of the engine. This requirement is included in the FDOC permit conditions.

Section 60.4214 states that owner of engines that are stationary emergency standby engines are not required to submit an initial notification

ACID RAIN

40 CFR Part 72- Subpart A – Acid Rain Program

This part establishes general provisions and operating permit program requirements for sources and units affected under the Acid Rain program, pursuant to Title IV of the Clean Air Act. The combustion turbines of this project are affected by this Acid Rain Program as a utility unit in accordance with Section 72.6(a).

40 CFR Part 72- Subpart C – Acid Rain Permit Applications

This subpart requires any source with an affected unit to submit a complete Acid Rain permit application by the applicable deadline. Requirement for submittal of Acid Rain Program application is included in the FDOC permit conditions. The Applicant submitted the Acid Rain permit application to the District on September 4, 2008.

40 CFR Part 73- Sulfur Dioxide Allowance System

This part establishes the requirements and procedures for the allocation of sulfur dioxide emission allowances; the tracking, holding and transfer of allowances; the deduction of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to Parts 72; the sale of allowances through EPA-sponsored auctions and a direct sale; the application for allowances from the Conservation and Renewable Energy Reserve; and the application for allowances for desulfurization of fuel by small diesel refineries. Requirements from this part will be included in evaluation for the Acid Rain program application required by Part 72.

40CFR Part 75 – Continuous Emission Monitoring

This part established requirements for the monitoring, recordkeeping, and reporting of SO2, NOx, and CO2 emissions, volumetric flow, and opacity data from emission units under the Acid Rain Program. The regulations include general requirements for the installation, certification, operation, and maintenance of continuous emission or opacity monitoring systems, certification tests and procedures, and quality assurance tests and procedures. Subpart B on Monitoring Provisions established general operating requirements for the monitoring systems. Subpart C establishes requirements on initial certification and recertification procedures. Subparts F and G establish requirements on recordkeeping and reporting requirements. All applicable requirements are included in the FDOC permit conditions.

VI. ADDITIONAL ISSUES

PARTICULATE EMISSION RELATING TO THE USE OF DESALINATED WATER FOR EVAPORATIVE COOLING

The proposed Siemens turbines have inlet air filters located upstream of the evaporative coolers. The evaporative cooler is turned on only during normal operation when ambient temperature is higher than 60°F. The particulate emission factor of 9.5 lbs/hr provided by the turbine vendor includes anticipated particulate matter from the evaporative cooler parameters since the water supply is expected to comply with the vendor's recommended water quality standards. Therefore, no further particulate emissions from the evaporative cooler are included in the emission calculation.

COMMISSIONING PERIOD

After construction of the equipment has been completed, the Applicant will be allowed a commissioning period of 120 days or 415 operating hours for each turbine, whichever comes sooner. During the 120-day commissioning period, the turbines will go through testing and tuning to ensure that the equipment is working properly and will be able to comply with all the FDOC emission limits. However, during the initial startup, certain emissions standards must remain in effect. These include the 72.11 tons/yr limit for NOx, hourly mass emission limits for NOx and CO to ensure there will be no violation of any state or national ambient air quality standards, and the hourly concentration limits for NOx to ensure compliance with the District RACT and BARCT Rules 69.3 and 69.3.1, respectively. A CEMS will be required to be installed at the time of initial startup to monitor emissions during the commissioning period from each turbine.

Once the emissions control equipment has been installed and is in good working order, the turbines must meet all BACT/LAER standards and permit requirements. CEMS and source testing will be used to show compliance with these standards.

SOURCE TEST FREQUENCY

The FDOC permit conditions require that the frequency of annual compliance source testing be in accordance with the applicable RATA frequency requirements of the federal acid rain program provisions at 40 CFR Part 75, Appendix B, Sections 2.3.1 and 2.3.3. The annual source testing is to show compliance with the NOX, CO, VOC, PM10, and ammonia emission limits and to verify the accuracy of the continuous emission monitoring system (CEMS). At a minimum, the acid rain programs provisions require that a source test be performed after four calendar quarters in which the unit operates at least 168 hours in each quarter (any hour the turbine combusts fuel is considered an operating hour for purposes of Part 75). It is expected that a source test would be required once per year for this facility since the Applicant anticipates about 4000 operating hours per year for each turbine, or about 1000 hours per quarter on average.

In cases of where low levels of operation (less than 168 operation hours per quarter) do not trigger a source test, the acid rain program provisions require a test be conducted every eight calendar quarters even if there have not been four quarters with 168 hours or more of operating time in the eight-quarter period. Any such test must be conducted within 720 operating hours of the end of the eight-quarter period.

VII. CONCLUSIONS AND RECOMMENDATIONS

A Final Determination of Compliance confers the same rights and privileges as an Authority to Construct only when and if the California Energy Commission (CEC) approves the Application For Certification, and the CEC certificate includes all conditions of the Final Determination of Compliance as included in the FDOC by the Air Pollution Control Officer.

If operated in accordance with the conditions specified in this Final Determination of Compliance, this equipment is expected to operate in compliance with all Rules and Regulations of the San Diego County Air Pollution Control District.

Originally Signed by Steven Moore/for — 8-4-09

Project Engineer Canqui Nguyen — Date

Originally Signed by Steven Moore — 8-4-09

Senior Engineer Approval — Date

APPENDIX A

APPROVAL OF AIR QUALITY IMPACT ANALYSIS

AIR QUALITY IMPACT ANALYSIS

FINAL REVIEW REPORT

CARLSBAD ENERGY CENTER PROJECT
APPLICATION 985423

SEPTEMBER 24, 2008

REVISED JULY 27, 2009

Prepared For
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JULY 27, 2009 AQIA Report Revisions

1. Table 4-1, Maximum Background Concentrations, Project Area, 2004-2006. (Corrected CO background and rounded other background values)

2. Table 4-4, Modeled Maximum Proposed Project Impacts (Corrected CO background and rounded other background values)

3. Table 5.1-29, Maximum Background Concentrations, project areas, 2004-2006 (AFC Table submitted September 2007 and revised September 24, 2008) (Corrected CO background and rounded other background values)

4. Section 5.0, Conclusion (Revised discussion regarding PM10 and PM2.5 SILs)

1.0 INTRODUCTION

An Air Quality Impact Analysis (AQIA) was performed for the Carlsbad Energy Center Project (CECP) by Sierra Research of Sacramento, CA. This report focuses on Section 5.1 of the AFC and the AQIA analysis results provided in the original (September, 2007) and subsequent modeling analysis performed (May 13, 2008).

2.0 PROJECT DESCRIPTION

NRG Energy, Inc. is proposing to remove three existing boilers at the Encina Power Station (Units 1, 2 and 3) and install two new Siemens Rapid Response SGT6-5000F Combined Cycle (R2C2) combustion turbine generators (CTGs). The gas turbines will be equipped with steam power augmentation and evaporative cooling. Each gas turbine is followed by a heat recovery steam generator (HRSG) and condensing steam turbine generator. The two units will provide a total nominal generating capacity of 558 MW net.

3.0 AIR QUALITY IMPACT ANALYSIS

Dispersion modeling was conducted for Normal, Startup/Shutdown and Commissioning period emissions of NO_2, CO, SO_2, and PM_{10} and $PM_{2.5}$. The applicant and their consultant (Sierra Research) worked closely with the District in developing modeling and analysis procedures in support of demonstrating compliance with all applicable NSR requirements. Modeling was performed in order to determine whether emissions during these time periods would impact the State and/or Federal Ambient Air Quality Standards for all criteria pollutants.

The modeling procedures are discussed in the following subsections.

3.1 MODELING METHODOLOGIES

AERMOD was used first to “screen” the different turbine stack emission and ambient temperature parameters for the conditions that generate the highest ground-level concentrations of criteria pollutants. Gas turbine specifications were developed and modeled for four temperature scenarios: extreme hot temperature (104 F), summer average temperature (74 F), annual average temperature (61 F) and extreme low temperature (37 F). Stack parameters and criteria pollutant emission rates were provided at each of these three ambient temperatures. Similarly, stack parameters and emission rates were provided at each ambient temperature for the turbines running at 100%, 75%, 60% and 50% load. The stack parameters and maximum emission rates for the screening modeling are presented in Table 3-1 and the maximum predicted screening model impacts are shown in Table 3-2.

After screening modeling, refined modeling was performed using EPA's AERMOD (Version 06341) model with the "maximum impact" turbine stack conditions and emission rates to determine the maximum criteria pollutant concentrations for the appropriate averaging periods for each criteria pollutant. Table 3-3 shows the inputs for the refined modeling.

Startup/Shutdown and Commissioning modeling for the elevated emission rates of NOx and CO existing during these conditions was also performed. The model inputs used to simulate those conditions are provided in Table 3-4.

Additionally, the EPA's SCREEN3 (Version 96043) model is used to determine the potential impacts if the project emissions are subjected to fumigation from breakup of the overnight inversion that can form. This special case is modeled as an extra precaution to avoid an exceedance of ambient air quality standards under these special atmospheric conditions.

All modeling was performed in accordance with EPA guidance and District standard procedures. Regulatory default settings were used. The receptor grid was sufficiently dense to identify maximum impacts.

3.2 METEOROLOGICAL DATA USED FOR DISPERSION MODELING

Meteorological data used for EPA's Aermod Prime model consisted of the following data for the 2003 through 2005 time period. The data was processed by the District using EPA's Aermet meteorological data processor (Version 06341) to produce Aermod ready files.

- Wind speed, wind direction, standard deviation of the horizontal wind direction and temperature from the District's Camp Pendleton monitoring station.

- Twice-daily upper-air soundings from Miramar Marine Corps Air Station, San Diego, CA.

- Cloud height and total opaque cloud amount from Palomar Airport, Carlsbad, CA.

- Wind speed, wind direction and temperature data from Palomar Airport, Carlsbad, CA for replacement of missing data in the Camp Pendleton data set.

- Wind speed, wind direction and temperature data with height from the District's wind profiler with RASS located near the Miramar Marine Corps Air Station, San Diego, CA.

Table 3-1
Screening Modeling Impacts

Table 5.1D-2 (Revised 5/11/08)
Screening Modeling Inputs
Data For Each Turbine

Case	Amb Temp deg F	Stack height feet	Stack Height meters	Stack Diam feet	Stack Diam meters	Stack flow wacfm	Stack flow m3/sec	Stack Vel ft/sec	Stack Vel m/sec	Stack Temp deg F	Stack Temp deg K
Avg. Peak	73.6	139.0	42.37	21.3	6.49	1,458,766	688.55	68.23	20.80	361.0	455.93
Avg. Base (cooler)	73.6	139.0	42.37	21.3	6.49	1,379,693	651.23	64.53	19.67	358.0	454.26
Avg. Base	73.6	139.0	42.37	21.3	6.49	1,351,217	637.79	63.20	19.26	356.0	453.15
Avg. Mid.	73.6	139.0	42.37	21.3	6.49	1,112,102	524.92	52.02	15.85	345.0	447.04
Avg. Low (60%)	73.6	139.0	42.37	21.3	6.49	981,319	463.19	45.90	13.99	340.0	444.26
Hot Peak	104	139.0	42.37	21.3	6.49	1,434,498	677.10	67.10	20.45	359.0	454.82
Hot Base (cooler)	104	139.0	42.37	21.3	6.49	1,373,686	648.39	64.25	19.58	366.0	458.71
Hot Base	104	139.0	42.37	21.3	6.49	1,244,127	587.24	58.19	17.74	352.0	450.93
Hot Mid.	104	139.0	42.37	21.3	6.49	1,025,286	483.95	47.96	14.62	336.0	442.04
Hot Low (60%)	104	139.0	42.37	21.3	6.49	912,246	430.59	42.67	13.01	331.0	439.26
Mild Base (cooler)	61	139.0	42.37	21.3	6.49	1,421,303	670.87	66.48	20.26	363.0	457.04
Mild Base	61	139.0	42.37	21.3	6.49	1,405,943	663.62	65.76	20.04	362.0	456.48
Mild Mid.	61	139.0	42.37	21.3	6.49	1,153,041	544.25	53.93	16.44	351.0	450.37
Mild Low (60%)	61	139.0	42.37	21.3	6.49	1,014,615	478.91	47.46	14.46	344.0	446.48
Cold Base	37.4	139.0	42.37	21.3	6.49	1,487,415	702.07	69.57	21.21	371.0	461.48
Cold Mid.	37.4	139.0	42.37	21.3	6.49	1,212,624	572.37	56.72	17.29	359.0	454.82
Cold Low (60%)	37.4	139.0	42.37	21.3	6.49	1,064,636	502.52	49.80	15.18	352.0	450.93

Case	NOx lb/hr	CO lb/hr	PM10 lb/hr	SOx lb/hr	NOx g/sec	CO g/sec	PM10 g/sec	SOx g/sec
Avg. Peak	15.02	9.15	9.50	4.37	1.893	1.153	1.197	0.550
Avg. Base (cooler)	14.13	8.60	9.50	4.11	1.780	1.084	1.197	0.517
Avg. Base	13.81	8.41	9.50	4.01	1.740	1.060	1.197	0.506
Avg. Mid.	11.22	6.83	9.50	3.26	1.414	0.861	1.197	0.411
Avg. Low (60%)	9.79	5.96	9.50	2.84	1.233	0.751	1.197	0.358
Hot Peak	14.76	8.99	9.50	4.29	1.860	1.132	1.197	0.540
Hot Base (cooler)	13.88	8.45	9.50	4.03	1.749	1.065	1.197	0.508
Hot Base	12.50	7.61	9.50	3.63	1.575	0.959	1.197	0.458
Hot Mid.	10.22	6.22	9.50	2.97	1.288	0.784	1.197	0.374
Hot Low (60%)	8.97	5.46	9.50	2.61	1.130	0.688	1.197	0.328
Mild Base (cooler)	14.51	8.84	9.50	4.22	1.828	1.113	1.197	0.531
Mild Base	14.34	8.73	9.50	4.17	1.807	1.100	1.197	0.525
Mild Mid.	11.63	7.08	9.50	3.38	1.465	0.892	1.197	0.426
Mild Low (60%)	10.12	6.16	9.50	2.94	1.275	0.777	1.197	0.371
Cold Base	15.13	9.21	9.50	4.40	1.907	1.161	1.197	0.554
Cold Mid.	12.23	7.45	9.50	3.55	1.541	0.938	1.197	0.448
Cold Low (60%)	10.63	6.47	9.50	3.09	1.339	0.815	1.197	0.389

Table 3-2
Screening Level Modeling Impacts

Table 5.1D-3 (Revised 5/11/08)
Screening Level Modeling Impacts
(Combined Impacts for Two Gas Turbines)

Operating Mode	NO2 1-hr	CO 1-hr	SO2 1-hr	SO2 3-hr	CO 8-hr	PM10 24-hr	SO2 24-hr	NO2 Annual	PM10 Annual	SO2 Annual
Avg. Peak	14.667	8.930	4.262	1.944	1.871	0.888	0.408	0.122	0.077	0.035
Avg. Base (cooler)	14.231	8.665	4.135	1.888	1.795	0.922	0.398	0.124	0.083	0.036
Avg. Base	13.268	8.078	3.855	1.872	1.775	0.935	0.395	0.125	0.086	0.036
Avg. Mid.	13.963	8.502	4.057	1.719	1.674	1.084	0.372	0.129	0.109	0.038
Avg. Low (60%)	13.265	8.077	3.854	1.780	1.604	1.175	0.352	0.129	0.125	0.037
Hot Peak	14.483	8.818	4.208	1.921	1.847	0.899	0.406	0.123	0.079	0.036
Hot Base (cooler)	14.032	8.543	4.077	1.839	1.758	0.917	0.389	0.120	0.082	0.035
Hot Base	13.527	8.236	3.930	1.788	1.685	0.996	0.381	0.127	0.096	0.037
Hot Mid.	13.046	7.943	3.791	1.731	1.633	1.151	0.360	0.130	0.121	0.038
Hot Low (60%)	12.062	7.344	3.505	1.797	1.566	1.238	0.340	0.129	0.137	0.038
Mild Base (cooler)	14.216	8.655	4.130	1.889	1.818	0.901	0.400	0.121	0.079	0.035
Mild Base	13.960	8.500	4.056	1.883	1.804	0.908	0.398	0.122	0.081	0.035
Mild Mid.	12.765	7.772	3.709	1.740	1.654	1.051	0.374	0.128	0.104	0.037
Mild Low (60%)	12.673	7.716	3.682	1.661	1.610	1.148	0.355	0.128	0.120	0.037
Cold Base	13.159	8.012	3.823	1.932	1.866	0.869	0.402	0.118	0.074	0.034
Cold Mid.	13.163	8.014	3.824	1.759	1.662	1.005	0.376	0.126	0.098	0.037
Cold Low (60%)	13.071	7.958	3.798	1.648	1.621	1.104	0.359	0.126	0.113	0.037

Table 3-3
Emission Rates and Stack Parameters for Refined Modeling

Table 5.1D-4A (Revised 5/11/08)
Emission Rates and Stack Parameters for Refined Modeling

						Emission Rates, g/s									Emission Rates, lb/hr			
	Stack Diam, m	Stack Height, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	NOx	SO2	CO	PM10	Stack Diam, ft	Stack Height, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	NOx	SO2	CO	PM10
Averaging Period: One hour NOx																		
Unit 6	6.5	42.4	456	688.5	20.8	1.8931	n/a	n/a	n/a	21.3	139	361	1,458,766	68	15.02	n/a	n/a	n/a
Unit 7	6.5	42.4	456	688.5	20.8	1.8931	n/a	n/a	n/a	21.3	139	361	1,458,766	68	15.02	n/a	n/a	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	0.2620	n/a	n/a	n/a	0.33	30	938	1,328	254	2.08	n/a	n/a	n/a
Averaging Period: One hour CO and SOx																		
Unit 6	6.5	42.4	456	688.5	20.8	n/a	0.5500	1.1526	n/a	21.3	139	361	1,458,766	68	n/a	4.37	9.15	n/a
Unit 7	6.5	42.4	456	688.5	20.8	n/a	0.5500	1.1526	n/a	21.3	139	361	1,458,766	68	n/a	4.37	9.15	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	0.0003	0.0305	n/a	0.33	30	938	1,328	254	n/a	0.00	0.24	n/a
Averaging Period: Three hours SOx																		
Unit 6	6.5	42.4	456	688.5	20.8	n/a	0.5500	n/a	n/a	21.3	139	361	1,458,766	68	n/a	4.37	n/a	n/a
Unit 7	6.5	42.4	456	688.5	20.8	n/a	0.5500	n/a	n/a	21.3	139	361	1,458,766	68	n/a	4.37	n/a	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	0.0001	n/a	n/a	0.33	30	938	1,328	254	n/a	0.00	n/a	n/a

Table 3-3 *(Continued)*
Emission Rates and Stack Parameters for Refined Modeling

Table 5.1D-4B (Revised 5/11/08)
Emission Rates and Stack Parameters for Refined Modeling (cont.)

						Emission Rates, g/s									Emission Rates, lb/hr			
	Stack Diam, m	Stack Height, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	NOx	SO2	CO	PM10	Stack Diam, ft	Stack Height, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	NOx	SO2	CO	PM10
Averaging Period: Eight hours CO																		
Unit 6	6.5	42.4	456	688.5	20.8	n/a	n/a	1.1526	n/a	21.3	139	361	1,458,766	68	n/a	n/a	9.15	n/a
Unit 7	6.5	42.4	456	688.5	20.8	n/a	n/a	1.1526	n/a	21.3	139	361	1,458,766	68	n/a	n/a	9.15	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	n/a	0.0038	n/a	0.33	30	938	1328	254	n/a	n/a	0.03	n/a
Averaging Period: 24-hour SOx																		
Unit 6	6.5	42.4	456	688.5	20.8	n/a	0.5500	n/a	n/a	21.3	139	361	1,458,766	68	n/a	4.37	n/a	n/a
Unit 7	6.5	42.4	456	688.5	20.8	n/a	0.5500	n/a	n/a	21.3	139	361	1,458,766	68	n/a	4.37	n/a	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	0.0000	n/a	n/a	0.33	30	938	1,328	254	n/a	0.00	n/a	n/a
Averaging Period: 24-hour PM10																		
Unit 6	6.5	42.4	439	430.5	13.0	n/a	n/a	n/a	1.1970	21.3	139	331	912,246	43	n/a	n/a	n/a	9.50
Unit 7	6.5	42.4	439	430.5	13.0	n/a	n/a	n/a	1.1970	21.3	139	331	912,246	43	n/a	n/a	n/a	9.50
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	n/a	n/a	0.0002	0.33	30	938	1,328	254	n/a	n/a	n/a	0.00

Table 3-3 *(Continued)*
Emission Rates and Stack Parameters for Refined Modeling

Table 5.1D-4C (Revised 5/11/08)
Emission Rates and Stack Parameters for Refined Modeling (cont.)

						Emission Rates, g/s									Emission Rates, lb/hr			
	Stack Diam, m	Stack Height, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	NOx	SO2	CO	PM10	Stack Diam, ft	Stack Height, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	NOx	SO2	CO	PM10
Averaging Period: Annual NOx and SOx																		
Unit 6	6.5	42.4	442	483.9	14.6	1.0865	0.0807	n/a	n/a	21.3	139	336	1,025,286	48	8.62	0.64	n/a	n/a
Unit 7	6.5	42.4	442	483.9	14.6	1.0865	0.0807	n/a	n/a	21.3	139	336	1,025,286	48	8.62	0.64	n/a	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	0.0015	0.0000	n/a	n/a	0.33	30	938	1,328	254	0.01	0.00	n/a	n/a
Averaging Period: Annual PM10																		
Unit 6	6.5	42.4	439	430.5	13.0	n/a	n/a	n/a	0.5602	21.3	139	331	912,246	43	n/a	n/a	n/a	4.45
Unit 7	6.5	42.4	439	430.5	13.0	n/a	n/a	n/a	0.5602	21.3	139	331	912,246	43	n/a	n/a	n/a	4.45
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	n/a	n/a	0.0000	0.33	30	938	1,328	254	n/a	n/a	n/a	0.00

Table 3-4
Startup/Shutdown and Commissioning Modeling Inputs

Table 5.1D-6 (Revised 5/11/08)

Startup/Shutdown and Commissioning Modeling Inputs

Operating Case	Amb Temp deg F	Stack height feet	Stack Height meters	Stack Diam feet	Stack Diam meters	Stack flow wacfm	Stack flow m3/sec	Stack Vel ft/sec	Stack Vel m/sec	Stack Temp deg F	Stack Temp deg K
Startup/Shutdown											
Unit 6 - Startup/Shutdown	104	139	42.37	21.3	6.49	858,818	405.37	40.17	12.24	346.00	447.59
Unit 7 - Startup/Shutdown	104	139	42.37	21.3	6.49	858,818	405.37	40.17	12.24	346.00	447.59
Commissioning											
One Unit In Commissioning	104	139	42.37	21.3	6.49	858,818	405.37	40.17	12.24	346.00	447.59
One Unit in Startup/Shutdown	104	139	42.37	21.3	6.49	858,818	405.37	40.17	12.24	346.00	447.59

	NOx lb/hr	CO lb/hr		NOx g/sec	CO g/sec
Startup/Shutdown					
Unit 6 - Startup/Shutdown	85.64	813.52		10.79	102.50
Unit 7 - Startup/Shutdown	85.64	813.52		10.79	102.50
Commissioning					
One Unit in Commissioning	200.13	3812.63		25.22	480.39
One Unit in Startup/Shutdown	85.64	813.52		10.79	102.50

4.0 AIR QUALITY IMPACT ANALYSIS RESULTS

In accordance with EPA and San Diego Air Pollution Control District New Source Review Guidance and the modeling methodologies described above, maximum predicted concentrations associated with facility operations were determined for each of the required criteria pollutant and the applicable averaging period during Normal, Startup/Shutdown and Commissioning conditions. The maximum predicted concentrations occurring during any of the operating conditions modeled were added to worst-case background concentrations for comparison to Federal and State Ambient Air Quality Standards. Worst case background concentrations were determined from the review of 3 years (2004-2006) of monitoring data taken from the District's Camp Pendleton, Escondido or San Diego monitoring stations, whichever was available for a specific criteria pollutant and deemed to be most representative of air quality in the facility area. Table 4-1 summarizes the worst case background concentrations.

The maximum ground-level impacts at any location from normal operations, startup/shutdowns and the special circumstances of inversion breakup fumigation are given in Table 4-2.

Table 4-3 provides the summary of project modeled maximum impacts for Commissioning period operating conditions.

Table 4-4 provides the summary of the proposed project modeled maximum impacts, including worst case ambient background concentrations, compared with Federal and California Ambient Air Quality Standards (AAQS).

Table 4-5 provides a comparison of maximum modeled impacts during normal operation and PSD significant impact levels.

TABLE 4-1
MAXIMUM BACKGROUND CONCENTRATIONS[a], PROJECT AREA, 2004-2006 (μg/m^3)—REVISED JUNE 25, 2009

Pollutant	Averaging Time	2004	2005	2006
NO_2 (Camp Pendleton)	1-hour	**186**	145	152
	Annual	**23**	23	21
SO_2 (San Diego)	1-hour	**110**	105	89
	3-hour	52	68	**79**
	24-hour	**24**	24	24
	Annual	**10**	8	10
CO (Escondido)	1-hour	**7210**	6753	6524
	8-hour	**4361**	3548	4136
PM_{10} (Escondido)	24-hour	**58**	42	52
	Annual	**27**	24	24
$PM_{2.5}$ (Escondido)	24-hour[b]	37	32	28
	Annual	**14.1**	12.3	11.5

Source: California Air Quality Data, California Air Resources Board website; EPA AIRData website. Reported values have been rounded to the nearest tenth of a μg/m^3 except for PM_{10} which were already rounded to the nearest integer.

Notes:

a. With the exception of 24-hr $PM_{2.5}$, bolded values are the highest during the three years and are used to represent background concentrations.

b. 24-hour average $PM_{2.5}$ concentrations shown are 98th percentile values rather than highest values because compliance with the ambient air quality standards is based on 98th percentile readings. Since the ambient standard is based on a 3-year average of the 98th percentile readings, the 3-year average of the 2004 to 2006 98th percentile readings was used to represent the background concentration.

TABLE 4-2

NORMAL OPERATION AIR QUALITY MODELING RESULTS FOR NEW EQUIPMENT

Pollutant	Averaging Time	Modeled Maximum Concentrations ($\mu g/m^3$) Normal Operations AERMOD	Startup/Shutdown AERMOD	Fumigation SCREEN3	Shoreline Fumigation SCREEN3
Combined Impacts Both CTGs					
NO_2	1-hour	13.3	80.4	2.6	18.5
	Annual	0.1	a	c	c
SO_2	1-hour	4.3	b	0.8	5.4
	3-hour	2.0	b	0.6	4.8
	24-hour	0.4	b	0.3	0.5
	Annual	0.0	b	c	c
CO	1-hour	9.0	1133.8	1.6	11.3
	8-hour	1.9	236.0	1.0	3.5
$PM_{2.5}/PM_{10}$	24-hour	1.2	b	0.9	1.7
	Annual	0.1	b	c	c
Fire pump Engine					
NO_2	1-hour	108.0	d	e	e
	Annual	0.1	d	e	e
SO_2	1-hour	0.2	d	e	e
	3-hour	0.0	d	e	e
	24-hour	0.0	d	e	e
	Annual	0.0	d	e	e
CO	1-hour	18.2	d	e	e
	8-hour	1.0	d	e	e
$PM_{2.5}/PM_{10}$	24-hour	0.0	d	e	e
	Annual	0.0	d	e	e
Combined Impacts New Equipment					
NO_2	1-hour	108.0	f	f	f
	Annual	0.1	f	f	f
SO_2	1-hour	4.3	f	f	f
	3-hour	2.0	f	f	f
	24-hour	0.4	f	f	f
	Annual	0.0	f	f	f
CO	1-hour	18.2	f	f	f
	8-hour	1.9	f	f	f
$PM_{2.5}/PM_{10}$	24-hour	1.2	f	f	f
	Annual	0.1	f	f	f

a. Not applicable, because startup/shutdown emissions are included in the modeling for annual average.
b. Not applicable, because emissions are not elevated above normal operation levels during startups/shutdowns.
c. Not applicable, because inversion breakup is a short-term phenomenon and as such is evaluated only for short-term averaging periods.
d. Not applicable, because engine will not operate during CTG startups/shutdowns.
e. Not applicable, this type of modeling is not performed for small combustion sources with relatively short stacks.
f. Impacts are the same as shown for CTGs.

TABLE 4-3

MODELED IMPACTS DURING COMMISSIONING (COMBINED IMPACTS BOTH CTGS)

Pollutant/Averaging Period	Modeled Concentration, µg/m^3
NO_2 – 1-hour	127.5
CO – 1-hour	3228.0
CO - 8-hour	675.9

TABLE 4-4

MODELED MAXIMUM PROPOSED PROJECT IMPACTS

REVISED June 25,2009

Pollutant	Averaging Time	Maximum Project Impact (µg/m^3)	Background (µg/m^3)	Total Impact (µg/m^3)	State Standard (µg/m^3)	Federal Standard (µg/m^3)
NO_2	1-hour	127.5[a]	186	314	338	-
	Annual	0.1	23	23	56	100
SO_2	1-hour	4.3	110	114	650	-
	3-hour	2.0	79	81	-	1300
	24-hour	0.4	24	24	109	365
	Annual	0.0	10	10	-	80
CO	1-hour	3,228.0[a]	7210	10438	23,000	40,000
	8-hour	675.9[a]	4361	5037	10,000	10,000
PM_{10}	24-hour	1.2	58	59	50	150
	Annual	0.1	27	27	20	--
$PM_{2.5}$	24-hour	1.2	32.7[b]	34	--	35
	Annual	0.1	14.1	14	12	15

Notes:

a. Impacts during gas turbine commissioning.

b. Three year average of 98th percentile.

TABLE 4-5

COMPARISON OF MAXIMUM MODELED IMPACTS DURING NORMAL OPERATION AND PSD SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Significant Impact Level, μg/m³	Maximum Modeled Impact for CECP, μg/m³	Exceed Significant Impact Level?
NO_2	Annual	1	0.1	No
SO_2	3-hour	25	2.0	No
	24-Hour	5	0.4	
	Annual	1	0.0	
CO	1-Hour	2000	1134	No
	8-Hour	500	236	
PM_{10}	24-Hour	5	1.2	No
	Annual	1	0.1	

5.0 CONCLUSION

The results of the modeling indicate that the proposed facility operations including Commissioning and Startup/Shutdowns will not cause or contribute to an exceedance of the Federal and California Ambient Air Quality Standards for NO_2, SO_2 and CO.

For PM_{10}, background concentrations already exceed the annual and 24 hour California standard. Since the background is already in exceedance of the annual standard no additional violations can be due to facility operations. Additionally the 0.1 μg/m³ predicted annual impact is well below PSD significant impact levels shown in Table 4-5. Predicted impacts less than SILs are normally considered to not significantly affect compliance with Federal Ambient Air Quality Standards regardless of the background level. Specifically in non-attainment areas, project impacts less than the SILs are deemed to not significantly cause or contribute to violations **of, or attainment of**, of the Federal Ambient Air Quality Standard. This can be considered the case for California **PM10** Ambient Air Quality Standards as well.

Since the initial modeling estimated maximum 24 Hour PM_{10} impacts of approximately 1.2 μg/m³, additional AERMOD modeling could be performed for all days in the 2004-2006 period that 24 Hour PM_{10} background concentrations were between 49 μ/m³ and 50 μg/m³ (California Standard) to determine whether additional violations would result from facility operations. There were no monitoring days that concentrations were measured within this range (highest monitored value less than the California Standard was 44 μg/m³. Therefore it can be concluded that facility operations would not cause or contribute to additional violations of the California 24 Hour Ambient Air Quality Standard for PM_{10}.

The modeling results also indicate that no exceedance of the Federal annual or 24 hour PM2.5 standard is predicted. Monitored background levels exceeded the California annual standard. Since the background is already in exceedance of the annual standard no additional violations can be due to facility operations. **Additionally the 0.1 μg/m³ predicted annual impact is well below PSD significant impact levels shown in Table 4-5 for PM10 and also well below all of the proposed SILs for PM2.5. Predicted impacts less than SILs are normally considered**

to not significantly affect compliance with Federal Ambient Air Quality Standards regardless of the background level. Specifically in non-attainment areas, project impacts less than the SILs are deemed to not significantly cause or contribute to violations of, or attainment of, the Federal Ambient Air Quality Standard. This can be considered the case for California PM2.5 Ambient Air Quality Standards as well.

5.1 AFC SECTION 5.1 REVISIONS

The following are revisions to Tables included in Section 5.1, Air Quality of the original AFC (CEC) and application for an Authority to Construct (SDAPCD) submittal dated September, 2007.

TABLE 5.1-6

PM_{10} LEVELS IN SAN DIEGO COUNTY, ESCONDIDO MONITORING STATION, 1997-2006 (µg/m³)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 24-Hour Average	63	51	50	63	72	50	124 *	58	42	52
Annual Arithmetic Mean (State Standard = 20 µg/m³)	29	24	30	30	31	25	33	27	24	24
Number of Days Exceeding:										
State Standard (50 µg/m³, 24-hour)	3	1	1	2	2	1	5	1	0	1
Federal Standard (150 µg/m³, 24-hour)	0	--	0	0	0	0	3	0	0	0

Source: California Air Quality Data, California Air Resources Board website (http://www.arb.ca.gov/adam/welcome.html; EPA AIRData website (http://www.epa.gov/air/data/index.html).

*Removed exceptional event value of 179

TABLE 5.1-7
$PM_{2.5}$ LEVELS IN SAN DIEGO COUNTY, ESCONDIDO MONITORING STATION, 1997-2006 (µg/m^3)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 24-Hour Average	--	--	64.0	66.0	60.0	54.0	38.0	67.0	43.0	41.0
Number of Days Exceeding:										
Federal Standard (65 µg/m^3, 24-hour)	0	0	0	1	0	0	0	1	0	0
(35 µg/m^3, 24-hour effective December 17, 2006)	--	--	--	--	--	--	--	--	--	--
98th Percentile	--	--	45.0	48.0	41.0	39.0	34.0	37.0	32.0	28.0
3-yr Average, 98th Percentile	--	--	--	--	44.7	42.7	38.0	36.7	34.3	32.3
Annual Arithmetic Mean (State Std = 12 µg/m^3)	--	--	18.0	15.8	17.5	16.0	14.1	14.1	12.3	11.5
3-yr Annual Average (Federal Std = 15 µg/m^3)	--	--	18	16	18	16	14	14	12	12

Source: California Air Quality Data, California Air Resources Board website (http://www.arb.ca.gov/adam/welcome.html; EPA AIRData website (http://www.epa.gov/air/data/index.html).

TABLE 5.1-29
Maximum Background Concentrations[a], project area, 2004-2006 (µg/m3)
Revised June 25, 2009

Pollutant	Averaging Time	2004	2005	2006
NO_2 (Camp Pendleton)	1-hour	**186**	145	152
	Annual	**23**	23	21
SO_2 (San Diego)	1-hour	**110**	105	89
	3-hour	52	68	**79**
	24-hour	**24**	24	24
	Annual	**10**	8	10
CO (Escondido)	1-hour	**7210**	6753	6524
	8-hour	**4361**	3548	4136
PM_{10} (Escondido)	24-hour	**58**	42	52
	Annual	**27**	24	24
$PM_{2.5}$ (Escondido)	24-hour[b]	37	32	28
	Annual	**14.1**	12.3	11.5

Source: California Air Quality Data, California Air Resources Board website; EPA AIRData website. Reported values have been rounded to the nearest tenth of a µg/m^3 except for PM_{10} which were already rounded to the nearest integer.

Notes:

a. With the exception of 24-hr $PM_{2.5}$, bolded values are the highest during the three years and are used to represent background concentrations.

b. 24-hour average $PM_{2.5}$ concentrations shown are 98th percentile values rather than highest values because compliance with the ambient air quality standards is based on 98th percentile readings. Since the ambient standard is based on a 3-year average of the 98th percentile readings, the 3-year average of the 2004 to 2006 98th percentile readings was used to represent the background concentration.

APPENDIX B

APPROVAL OF HEALTH RISK ASSESSMENT

Rule 1200 Health Risk Assessment Report

Facility ID:	333A
Applications:	985745, 985747, and 985748.
Project Engineer:	Steve Moore
Toxics Risk Analyst:	Michael Kehetian
HRA Tools Used:	AERMOD (Version 07026) and HARP (Version 1.4a)
Report Date:	08/03/09

Review of Supplemental Health Risk Assessment (HRA) evaluation for the Carlsbad Energy Center Project (CECP) dated April 29, 2009

A supplemental health risk assessment (HRA) was performed for the Carlsbad Energy Center Project (CECP), 4600 Carlsbad Blvd, Carlsbad, CA 92008 by Sierra Research and submitted to the District for review on April 29, 2009.

The supplemental HRA evaluation incorporates updates by the Office of Environmental Health Hazard Assessment (OEHHA) to the guidelines for conducting health risk assessments under the Air Toxics Hot Spots Program (Health and Safety Code Section 44360(b)(2)). The guideline methodology was revised to reflect scientific knowledge and techniques developed since the previous guidelines were prepared, and in particular to explicitly include consideration of possible differential effects on the health of infants, children and other sensitive subpopulations, in accordance with the mandate of the Children's Environmental Health Protection Act (Senate Bill 25, Escutia, Chapter 731, Statutes of 1999, Health and Safety Code Sections 39669.5 et seq). On June 18, 2008, the Scientific Review Panel on Toxic Air Contaminants (TACs) approved the final versions of the methodology section and the associated methodological appendices for the revised Technical Support Document (TSD) for the updates. Subsequently, on December 19, 2008, OEHHA formally adopted the revised Air Toxics Hot Spots Program Technical Support Document for the Derivation of Noncancer Reference Exposure Levels (RELs), adopting a new 8-hour REL and revised chronic and acute RELs for acetaldehyde, acrolein, arsenic, formaldehyde, manganese, and mercury. The formal adoption of the new and revised RELs required them to be used in any HRA performed under Rule 1200. Even though an HRA had been performed for the CECP prior to the Preliminary Determination of Compliance (PDOC) issuance on November 20, 2008, Rule 1200 requires that an HRA be performed including the OEHHA updates since final approval of the project had not been granted.

This supplemental HRA has been updated to include the most recent Consolidated Table of OEHHA / Air Resources Board (ARB) Approved Risk Assessment Health Values dated February 9, 2009, which incorporates the OEHHA new and revised RELs. The supplemental HRA also includes additional refinements in the HRA requested by the District. These refinements are detailed in the Sierra Research submittal.

RESULTS & CONCLUSION

SOURCES & OPERATIONS REVIEWED

Rule 1200 requires the HRA address the increases in potential to emit (PTE) associated with any new or modified emission units. The only emission increases for the CECP are associated with the following new equipment:

- Two natural gas-fueled combined-cycle combustion turbines each maximally rated at 2085 MMBtu/hr at an ambient temperature of 37 ^{o}F, without power augementation, and equipped with an oxidation catalyst to control volatile organic compounds (VOC) and carbon monoxide (CO) emissions. The oxidation catalyst also serves to control toxic air contaminant emissions, which, for this source, are all VOCs. The combustion turbines are also equipped with evaporative coolers that can be used cool the inlet air to each turbine to increase power during periods of high ambient temperature and steam augmentation that also can be used to increase power.

- One diesel-fired emergency fire pump rated at 246 brake horsepower (bhp).

The operating scenarios evaluated included startups, shutdowns, normal full load operations, during the commissioning year and noncommissioning years. The scenarios evaluated were determined to be sufficient in scope to adequately characterize the maximum potential health impacts.

WORST-CASE POTENTIAL HEALTH IMPACTS

Based on the review of the applicant's submittal, the expected and the likely worst-case potential health impacts from the emissions of toxic air contaminants for the project as compared to Rule 1200 significance levels are presented in the table below. The worst-case residential incremental cancer risk health impacts are based on the evaluation of gas turbines operating 8760 hours during the commissioning year in which both turbines have 1460 starups and shutdowns (excluding commissioning), commissioning operations for 415 hours, and 6662 hours at full load mode. In addition, the diesel-fueled emergency water pump is assumed to operate for 50 hours. Both commissioning and non-commissioning year operating cases used in the modeling to estimate cancer, chronic, 8-hour, and acute health impacts are described further in this report.

Category	**Health Impact**	**District Rule 1200 Significance Level**
Maximum Incremental Cancer Risk – Resident (per million)	0.47	1.0 or 10 (with TBACT)
Maximum Incremental Cancer Risk – Worker (per million)	0.27	1.0 or 10 (with TBACT)
Total Chronic Noncancer Health Hazard Index - Resident	0.01	1.0
Total Chronic Noncancer Health Hazard Index - Worker	0.01	1.0
Total Acute Noncancer Health Hazard Index	0.16	1.0
Total 8-Hour Noncancer Health Hazard Index	0.12	1.0

The major contributors to the risk are:

- Cancer risk is primarily due to noninhalation exposure to polycyclic aromatic hydrocarbons through oral exposure, dermal contact, soil ingestion, and for residential exposure, the non-urban home grown produce pathway. The polycyclic aromatic hydrocarbons were evaluated as benzo[a]pyrene where there was not a risk factor available for the compound, which likely results in conservatively high estimate of their impact.

- The chronic health hazard index (HHI) is primarily due to emissions of formaldehyde from the combustion turbines and diesel particulate matter from the diesel-fueled emergency fire pump.

- The 8-hour hazard index is due mainly to emissions of formaldehyde from the combustion turbines.

- The acute hazard index is primarily due to emissions of formaldehyde and acrolein from the combustion turbines and the emergency fire pump.

It should be noted that the potential health risks presented in the table above are conservatively high due to the conservative assumptions specified in the California Office of Health Hazard Assessment (OEHHA) health risk assessment guidance. In addition, the maximum health risks presented are based on an operating scenario that may be unrealistic—8760 hours of operation, including 1460 startups—and may not be possible because of constraints imposed by proposed permit conditions for criteria pollutants.

The reported occupational cancer, chronic, 8-hour, and acute worst-case potential health impacts are at the point of maximum impact (PMI), which is the maximum impact point beyond the facility boundary and although conservative, does not necessarily represent the actual health effects because a person may not reasonably be expected to be present at the PMI location for the exposure period of concern. Although the reported residential cancer risk at the PMI is estimated to be 1.22 in a million, the District has identified the risk to actual exposed residents to be well below the maximum impact point.

CONCLUSION

The indicated health impacts are all less than the Rule 1200 minimum significance levels. The maximum incremental cancer risk for a resident is 0.47 in a million and is 0.27 in a million for a worker. Because the incremental cancer risk is equal to or less than one in a million, the project is approvable without toxic best available control technology (TBACT) applied. However, the combustion turbines are proposed to be equipped with a standard oxidation catalyst, which would be considered TBACT for this type of equipment if the risk was greater than one in a million.

RISK CHARACTERIZATION

The following assumptions and risk modeling choices were used to characterize the risk in the HRA:

- Mutipathway exposure assumed the OEHHA default deposition rate equal to 0.05 meters per second for emitted particles uncontrolled by a particulate matter control device.

- For calculating residential cancer risk, considering inhalation is not one of the two dominant pathways, the ARB Derived (Adjusted) Analysis Method was used, incorporating the adult high-end breathing rate equal to 393 Liters/Kilogram-day.

- A ground level concentration adjustment factor of 4.2 (24 / 8 hours per day times 7 / 5 days per week) was appropriately applied for the diesel-fueled emergency fire pump to calculate worker cancer risk and the chronic hazard index.

- Estimated cancer risk is conservatively high based on emissions of polycyclic aromatic hydrocarbons (PAHs) being appropriately evaluated as benzo[a]pyrene, referencing the OEHHA Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments, *Speciation for Specific Classes of Compounds: Polycyclic Aromatic Hydrocarbons (PAHs),* Section 8.2.3, August 2003.

- In addition, cancer and chronic health impacts include the required noninhalation pathways per the OEHHA Guidance Manual, *Determination of Noninhalation (Oral) Cancer Risk*, Section 8.2.4, and *Noncancer Chronic Health Impacts from the Oral Route*, Section 8.3.2.

- To determine the maximum 8-hour ground level concentration, the possibility that a person may potentially be exposed during any 24-hour period was considered. Thus, three 8-hour daily block periods were modeled (12am-8am, 8am-4pm, and 4pm-12am).

- Although risk characterization for determining noncancer health effects involves the summation of the total hazard index (THI) for each target organ for exposure to a mixture of TACs, the toxicological endpoints for this evaluation are not considered, for the purpose of initially presenting an overly conservative estimate of the potential hazard index impacts.

MODELING PROCEDURES

In the modeling submitted, cancer, chronic, 8-hour, and acute risks were estimated using ARB's HARP, Version 1.4a, Risk Analysis Module to determine source strengths (g/s per ug/m^3) based on emission factors for the equipment and operating scenarios. The source strengths were input into EPA's AERMOD dispersion model to directly estimate health impacts. The District independently reviewed the AERMOD model inputs for adherence and technical accuracy with ARB and OEHHA guidance and District Rule 1200 standard procedures, incorporating the following references.

- OEHHA Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments, August 2003.
- OEHHA Air Toxics Hot Spots Program Technical Support Document for the Derivation of Noncancer Reference Exposure Levels, June 2008.
- Consolidated Table of OEHHA / ARB Approved Risk Assessment Health Values updated February 9, 2009.

The following AERMOD model inputs were reviewed:

- Annual and Hourly Emissions Rates (g/s)
- Cancer Potencies $(mg/kg\text{-}d)^{-1}$
- Chronic, 8-Hour, and Acute RELs (ug/m^3)
- OEHHA Adult High-End Breathing Rate = 393 (L/kg-d)
- Worker Point Estimate Breathing Rate = 149 (L/kg-d)
- Worker Exposure (5 days per week, 245 days per year, 40 years)
- Worker Ground Level Concentration (GLC) Adjustment for the diesel-fueled fire pump = 4.2
- Mutipathway (Dermal Contact, Soil Ingestion, and Home Grown Produce Non-Urban Fraction = 15%)

Receptor Grid

The dispersion modeling included a refined 25-meter receptor grid in addition to fenceline impacts along the property boundary of 25-meter resolution. The grid is sufficiently dense to identify maximum impacts.

OPERATING SCENARIOS

Turbine Startups and Shutdowns

For startup emissions, the HRA addresses the potential impact of low stack exhaust temperatures during the first few minutes of a cold start, which could increase the emission impacts. This was done by using a three phase startup hour: Phase I is the first 12 minutes of the startup, Phase 2 is the succeeding 10 minutes, and Phase 3 is the remainder of the hour. A shutdown was not included in the startup hour since The HRA done in conjunction with the PDOC showed that a startup hour without a shutdown resulted in higher impacts.

Based on the fact that the turbine is proposed, under normal circumstances, to achieve its BACT limits within 22 minutes of ignition. The stack exhaust temperature was assumed to rise linearly from ambient (68 °F) to its normal operating temperature in 22 minutes (no information on stack exhaust temperature was available from the manufacturer).

The turbine load was assumed to be 0% for first 5 minutes and then to rise at a rate of 30 MW per minute until the final operating load for the remainder of the startup hour was reached. This startup scenario was based on a presentation given by the turbine manufacturer[1]. The load was

[1]John Xia and Rick Antos, SGT6-5000F (W501F), 3 Million Hours Fleet Operational Experience, POWER-GEN International 2006, Orlando, FL, November 28-30, 2006.

calculated on a minute-by-minute basis, and average heat inputs for the four phases of the startup were calculated based on information provided by the manufacturer for steady state part load operation at an ambient temperature of 41 °F. A higher heating value for natural gas of 1020 Btu/scf was used in emission factor calculations.

Even though the turbine is projected to achieve its BACT limits in 22 minutes, the applicant has requested a 60-minute startup period. Therefore, in all cases, the final load was assumed to be 50% of the maximum load for the remainder of the hour (38 minutes) as a worst case analysis. A load of 50% was considered to be the worst case because: (1) this is the point of maximum fuel heat inputs at loads low enough for the much higher startup emission factors to be representative and (2) it is the point of minimum stack exhaust temperature at steady state conditions, based on manufacturer supplied data.

Shutdowns were assumed to occur in 7 minutes per the manufacturer information for shutdowns. For shutdowns, the minimum stack exhaust temperature was assumed to be the exhaust temperature at 50% load.

Turbine Commissioning Operations

For commissioning operations, the turbines were assumed to be operating at 50% load for same reasons as 50% load was chosen as the final load for the startup hour.

Turbine Normal Operations

The turbines were assumed to be operating at their maximum load for low ambient temperature (Case 15 in Table 5.1B-5 in the application). This case provides the highest toxic air contaminant emission rate for normal turbine operations.

Operating Cases – Potential to Emit (PTE) for Cancer and Chronic Health Impacts

In the annual HRA operating cases evaluated below, the number of operating hours for startup, commissioning, tuning, and low load are based on the FDOC permit limits (1460, 415, 40, and 13 hours per year, respectively). In addition, the applicant evaluated a maximum turbine annual operating case of 8760 hours per year at full load (no startup, shutdown, or commissioning hours).

- Noncommissioning Year: Gas Turbines operate for 8760 hours including 1460 startup hours, 1460 shutdowns, 40 hours of tuning and 13 hours of low-load (50%) operation, and 7077 hours at 100% load. In addition, the diesel-fueled emergency fire pump is assumed to operate for 50 hours.

- Commissioning Year: Gas Turbines operate for 8760 hours including 1460 startup hours, 1460 shutdown hours, 40 hours of combustor tuning and 13 hours of low-load (50%) operation, 415 hours of commissioning, and 6662 hours at 100% load. The diesel-fueled emergency fire pump is assumed to operate for 50 hours.

- Noncommissioning Year: Gas Turbines operate for 8760 hours at 100% load and 50 hours for the diesel-fueled emergency fire pump.

For each case, the impact for each turbine's operating mode (normal; startup phases 1, 2, and 3; shutdown; commissioning; tuning; and low-load operation) was weighted according to the annual operating hours for each mode. Further details are given in the Sierra Research submittal.

Operating Cases – Acute Health Impacts

- Simultaneous phased startup of gas turbine operating to a final operating load of 50% for the remainder of the hour and the maximum hourly fuel consumption rate (testing) of the emergency water pump.
- Commissioning of one gas turbine, second turbine undergoing phased startup to 50% load, and the maximum hourly fuel consumption rate (testing) of the emergency water pump.

For each case, the impact of each phase of the startup was weighted according to the minutes of operation for each phase. Further details are given in the Sierra Research submittal.

Operating Cases – 8 Hour Health Impacts

- During an 8-hour period, two simultaneous phased startup hours and 7-minute shutdowns for the gas turbines. For the remaining 346 minutes, the gas turbines operate at 100% load. The 8-hour period also consists of the maximum hourly fuel consumption rate (testing) emissions from the emergency water pump.
- One gas turbine undergoing commissioning for 8-hours while the other turbine operating with two simultaneous startup and two shutdown phases. In addition, the maximum hourly fuel consumption rate (testing) emissions from the emergency water pump.
- Both gas turbines operating at 100% load and the maximum hourly fuel consumption rate (testing) emissions from the emergency water pump.

For each case, the impact for each turbine operating mode (normal; startup phases 1, 2, and 3; shutdown; and commissioning) was weighted according to the minutes of operation for each mode. Further details are given in the Sierra Research submittal.

EMISSION FACTORS

Emissions Control – Gas Turbines

Since the gas turbines are proposed with an oxidation catalyst, the toxic air contaminant emission factors were reduced by 50% during normal operations.

Emission Factors – Gas Turbines during Normal Operation

With the exception of ammonia and formaldehyde, these emission factors are taken from AP-42 unless an AP-42 emission factor is not available. A uniform control factor of 50% to account for the use of an oxidation catalyst is applied to all emission factors except ammonia. The formaldehyde emission factor is taken from CATEF since the controlled emission factor is most representative of recent compliance source tests for a large combined-cycle turbine. The emission factor for ammonia is calculated from the proposed permit limit of 5 ppmd ammonia at 15% O_2

All PAHs listed in CATEF are represented. Those without an approved URF are quantified as composite PAHs.

The normal operation emission factors are shown below.

Toxic Air Contaminant	Emission Factor Uncontrolled (lb/MMscf)	Emission Factor Controlled (lb/MMscf)	Source
ACETALDEHYDE	4.08E-02	2.04E-02	AP-42
ACROLEIN	6.53E-03	3.27E-03	AP-42
AMMONIA	6.95	6.95	SDAPCD Permit
BENZENE	1.22E-02	6.10E-03	AP-42
BUTADIENE, 1,3-	4.39E-04	2.20E-04	AP-42
ETHYL BENZENE	3.26E-02	1.63E-02	AP-42
FORMALDEHYDE	9.17E-01	4.59E-01	CATEF
HEXANE-N	2.59E-01	1.30E-01	CATEF
NAPHTHALENE	1.33E-03	6.65E-04	AP-42
PAHs	--	--	--
ACENAPHTHENE	--	9.50E-06	CATEF
ACENAPTHYENE	--	7.34E-06	CATEF
ANTHRACENE	--	1.69E-05	CATEF
BENZO[a]ANTHRACENE	2.26E-05	1.13E-05	CATEF
BENZO[a]PYRENE	1.39E-05	6.95E-06	CATEF
BENZO[e]PYRENE	--	2.72E-07	CATEF
BENZO[b]FLUORANTHENE	1.13E-05	5.65E-06	CATEF
BENZO[k]FLUORANTHENE	1.10E-05	5.50E-06	CATEF
BENZO[g,h,i]PERYLENE	--	6.85E-06	CATEF
CHRYSENE	2.52E-05	1.26E-05	CATEF
DIBENZ[a,h]ANTHRACENE	2.35E-05	1.18E-05	CATEF
FLUORANTHENE	--	2.16E-05	CATEF
FLUORENE		2.90E-05	CATEF
INDENO(1,2,3-cd)PYRENE	2.35E-05	1.18E-05	CATEF
PHENANTHRENE	--	1.57E-04	CATEF
PYRENE	--	1.39E-05	CATEF
PROPYLENE	7.71E-01	3.86E-01	SDAPCD
PROPYLENE OXIDE	2.96E-02	1.48E-02	AP-42
TOLUENE	1.33E-01	6.65E-02	AP-42
XYLENES	6.53E-02	3.27E-02	AP-42

<u>Emission Factors – Gas Turbines during Startup and Shutdown</u>

For startup and shutdown emissions, the emission factors in the table below were used in the HRA. As indicated many of these emission factors were derived from a source test. The source test was performed during the first hour of a cold start of a natural gas-fueled GE 7FA gas turbine at the Palomar Energy Center. This is a combined-cycle turbine with ultra-low-NOx combustors. The turbine was equipped with an oxidation catalyst. During the first hour of the startup, the turbine tested was operating at very low loads (0–18%). Although the oxidation catalyst control efficiency was not quantified during the test it is assumed the catalyst was operating at reduced efficiency during a large portion of the hour because of the low temperatures in the heat recovery steam generator where the catalyst is located.

The District only considers these emission factors to be potentially applicable at loads below the point where the ultra-low-NOx combustors are no longer operating in the low-NOx mode (typically 40-60% of maximum load). This would include shutdown operations. However, emissions during a shutdown are likely to be overestimated with these emission factors because the oxidation catalyst would be close to its normal operating temperature.

Toxic Air Contaminant	Emission Factor (lb/MMscf)	Source
ACETALDEHYDE	1.28E+00	Source Test
ACROLEIN	6.89E-02	Source Test
AMMONIA	6.95	Permit
BENZENE	2.56E-02	Source Test
BUTADIENE, 1,3-	4.39E-04	AP-42
ETHYL BENZENE	3.26E-02	Source Test
FORMALDEHYDE	4.63E+00	Source Test
HEXANE-N	2.59E-01	CATEF
NAPHTHALENE	1.04E-03	Source Test
PAHs	--	--
ACENAPHTHENE	1.90E-05	CATEF
ACENAPTHYENE	1.47E-05	CATEF
ANTHRACENE	3.38E-05	CATEF
BENZO[a]ANTHRACENE	2.25E-05	Source Test (ND)[a]
BENZO[a]PYRENE	1.39E-05	Source Test (ND)[a]
BENZO[e]PYRENE	5.44E-07	CATEF
BENZO[b]FLUORANTHENE	1.13E-05	CATEF
BENZO[k]FLUORANTHENE	1.10E-05	CATEF
BENZO[g,h,i]PERYLENE	1.37E-05	CATEF
CHRYSENE	2.25E-05	Source Test (ND)[a]
DIBENZ[a,h]ANTHRACENE	2.25E-05	Source Test (ND)[a]
FLUORANTHENE	4.32E-05	CATEF
FLUORENE	5.80E-05	CATEF
INDENO(1,2,3-cd)PYRENE	2.25E-05	Source Test (ND)[a]
PHENANTHRENE	3.13E-04	CATEF
PYRENE	2.77E-05	CATEF
PROPYLENE	7.71E-01	CATEF
PROPYLENE OXIDE	2.96E-02	AP-42
TOLUENE	9.28E-02	Source Test
XYLENES	3.48E-03	Source Test

[a]These compounds were tested for but not detected during the source test.
The emission factor is based on one half the detection limit.

Emission Factors – Diesel Emergency Fire Pump

Toxic Air Contaminant	Emission Factor (lbs/1000 gal)*	Source
DIESEL PARTICULATE MATTER	3.53E-02 (lbs/hr)	Manufacturer
ACROLEIN	3.39E-02	SDAPCD
ARSENIC	1.60E-03	SDAPCD
BENZENE	1.86E-01	SDAPCD
COPPER	4.10E-03	SDAPCD
FORMALDEHYDE	1.73	SDAPCD
HYDROGEN CHLORIDE	1.86E-01	SDAPCD
MERCURY	2.00E-03	SDAPCD
NICKEL	3.90E-03	SDAPCD
TOLUENE	1.05E-01	SDAPCD
XYLENES	4.24E-02	SDAPCD

*Unless otherwise noted.

RELEASE PARAMETERS

The following release parameters were used in the HRA. They are based on the operating scenarios considered in the HRA.

Release Parameters – Gas Turbines (Potential to Emit, 100% Base Load)

Release Parameter	Value
Stack Height (ft)	139
Stack Diameter (ft)	21.3
Temperature deg F	361
Exhaust Velocity (fps)	68.44

Release Parameters – Gas Turbines (Startup, Shutdown, and Commissioning)

Operating Mode	Duration (Minutes)	Fuel Heat Input (MMBTU/hr)	Temperature (deg F)	Exhaust Velocity (fps)
Startup				
Phase 1	12	780	138	26.48
Phase 2	10	1257	281	37.70
Phase 3	38	1257	346	41.01
Shutdown	7	568.5	346	33.37
Commissioning	N/A	1257	346	41.01

Release Parameters – Diesel Emergency Fire Pump

Release Parameter	Value
Stack Height (ft)	30
Stack Diameter (ft)	0.33
Temperature deg F	938
Exhaust Velocity (fps)	253.63

PROCESS DATA

Process Data – Gas Turbines (Potential to Emit, 100% Base Load)

Operation Parameter	Value
Fuel Usage (MMBTU/hr)	2,085
Maximum annual hours of operation	8,760

Process Data – Diesel Emergency Fire Pump

Operation Parameter	Value
Engine horsepower (bhp)	246
Fuel Consumption (gal/hr)	12.2
Annual hours of operation	50

APPENDIX C

PERMIT CONDITIONS

CECP PERMIT CONDITIONS

GENERAL CONDITIONS

1. This equipment shall be properly maintained and kept in good operating condition at all times, and, to the extent practicable, the applicant shall maintain and operate the equipment and any associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. [Rule 21 and 40 CFR §60.11]

2. The applicant shall operate the project in accordance with all data and specifications submitted with the application under which this license is issued and District Application Nos. 985745, 985747, and 985748. [Rule 14]

3. The applicant shall provide access, facilities, utilities, and any necessary safety equipment, with the exception of personal protective equipment requiring individual fitting and specialized training, for source testing and inspection upon request of the Air Pollution Control District. [Rule 19]

4. The applicant shall obtain any necessary District permits for all ancillary combustion equipment including emergency engines, prior to on-site delivery of the equipment. [Rule 10]

5. Prior to the earlier of the initial startup dates for either of the two combustion turbines, the applicant shall surrender to the District Class A Emission Reduction Credits (ERCs) in an amount equivalent to 47.9 tons per year of oxides of nitrogen (NOx) to offset the net maximum allowable increase of 39.9 tons per year of NOx emissions for the two combustion turbines and the emergency fire pump engine described in District Application Nos. 985745, 985747, and 985748. [Rule 20.3(d)(8)]

6. A rolling 12-calendar-month period is one of a series of successive consecutive 12-calendar-month periods. The initial 12-month-calendar period of such a series shall begin on the first day of the month in which the applicable beginning date for that series occurs as specified in this permit. [Rule 20.3 (d)(3), Rule 20.3(d)(8) and Rule 21].

7. Pursuant to 40 CFR §72.30(b)(2)(ii) of the Federal Acid Rain Program, the applicant shall submit an application for a Title IV Operating Permit at least 24 months prior to the initial startup of the combustion turbines. [40 CFR Part 72]

8. The applicant shall comply with all applicable provisions of 40 CFR Part 73, including requirements to offset, hold and retire sulfur dioxide (SO_2) allowances. [40 CFR Part 73]

9. All records required by this permit shall be maintained on site for a minimum of five years and made available to the District upon request. [Rule 1421]

COMBUSTION TURBINE CONDITIONS

Definitions

10. For purposes of determining compliance with the emission limits of this permit, a shutdown period is the period of time that begins with the lowering of the gross electrical output (load) of the combustion

turbine below 114 megawatts (MW) and that ends five minutes after fuel flow to the combustion turbine ceases, not to exceed 35 consecutive minutes. [Rule 20.3(d)(1)]

11. A startup period is the period of time that begins when fuel flows to the combustion turbine following a non-operational period. For purposes of determining compliance with the emission limits of this permit, the duration of a startup period shall not exceed 60 consecutive minutes. [Rule 20.3(d)(1)]

12. A non-operational period is any five-consecutive-minute period when fuel does not flow to the combustion turbine. [Rule 20.3(d)(1)]

13. Tuning is defined as adjustments to the combustion or emission control system that involves operating the combustion turbine or emission control system in a manner such that the emissions control equipment may not be fully effective or operational. Only one gas turbine shall be tuned at any given time. Tuning events shall not exceed 720 unit operating minutes in a calendar day nor exceed 40 hours in a calendar year for each turbine. The District compliance division shall be notified at least 24 hours in advance of any tuning event. For purposes of this condition, the number of hours of tuning in a calendar year is defined as the total unit operating minutes of tuning during the calendar year divided by 60. [Rule 20.3(d)(1)]

14. A Continuous Emission Monitoring System (CEMS) protocol is a document approved in writing by the District that describes the methodology and quality assurance and quality control procedures for monitoring, calculating, and recording stack emissions from the combustion turbine that is monitored by the CEMS. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

15. A transient hour is a clock hour during which the change in gross electrical output produced by the combustion turbine exceeds 50 MW per minute for one minute or longer during any period that is not part of a startup or shutdown period. [Rule 20.3(d)(1)]

16. For each combustion turbine, the commissioning period is the period of time commencing with the initial startup of that turbine and ending the sooner of 120 calendar days from the initial startup, after 415 hours of turbine operation, or the date the pemittee notifies the District the commissioning period has ended. For purposes of this condition, the number of hours of turbine operation is defined as the total unit operating minutes during the commissioning period divided by 60. [Rule 20.3(d)(1)]

17. For each combustion turbine, the shakedown period is the period of time commencing with the initial startup of that turbine and ending the sooner of 180 calendar days from the initial startup or the date the permittee notifies the District that the shakedown period has ended. [Rules 20.1(c)(16) and 21]

18. Turbine A is the combustion turbine as described on Applications No. 985745 or No. 985747, as applicable, that first completes its shakedown period. If both turbines complete their shakedown period on the same date, then Turbine A is the turbine described on Application No. 985745. [Rules 20.1(c)(16) and 21]

19. Turbine B is the combustion turbine as described on Applications No. 985745 or No. 985747, as applicable, that last completes its shakedown period. If both turbines complete their shakedown period on the same date, then Turbine B is the turbine described on Application No. 985747. [Rules 20.1(c)(16) and 21]

20. Low load operation is a period of time that begins when the gross electrical output (load) of the combustion turbine is reduced below 114 MW and that ends 10 consecutive minutes after the combustion turbine load exceeds 114 MW, provided that fuel is continuously combusted during the entire period and one or more clock-hour concentration emission limits specified in this permit are exceeded as a result of the low-load operation. For each combustion turbine, periods of operation at low load shall not exceed 130 unit operating minutes in any calendar day nor an aggregate of 780 unit operating minutes in any calendar year. No low load operation period shall begin during a startup period. [Rule 20.3(d)(1)]

21. For each combustion turbine, a unit operating day, hour, and minute mean the following:
    a. A unit operating day means any calendar day in which the turbine combusts fuel.
    b. A unit operating hour means any clock hour in which the turbine combusts fuel.
    c. A unit operating minute means any clock minute in which the turbine combusts fuel and any clock minute that is part of a shutdown period.

    [Rule 21, 40 CFR Part 75, Rule 20.3(d)(1), 40 CFR Part 60 Subpart KKKK]

General Conditions

22. The exhaust stacks for each combustion turbine shall be at least 139 feet in height above site base elevation. [Rules 20.3(d)(2) and 1200]

23. The combustion turbines shall be fired on Public Utility Commission (PUC) quality natural gas. The permitee shall maintain, on site, quarterly records of the natural gas sulfur content (grains of sulfur compounds per 100 dscf of natural gas) and hourly records of the higher and lower heating values (btu/scf) of the natural gas; and provide records to District personnel upon request. [Rule 20.3(d)(1)]

24. Unless otherwise specified in this permit, all continuous monitoring data shall be collected at least once every minute. [Rules 69.3, 69.3.1, and 20.3(d)(1)]

Emission Limits

25. For purposes of determining compliance with emission limits based on source testing, the average of three subtests shall be used. For purposes of determining compliance with emission limits based on a Continuous Emission Monitoring System (CEMS), data collected in accordance with the CEMS protocol shall be used and the averages for averaging periods specified herein shall be calculated as specified in the CEMS protocol. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

26. For purposes of determining compliance with emission limits based on CEMS data, all CEMS calculations, averages, and aggregates shall be performed in accordance with the CEMS protocol approved in writing by the District. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

27. For each emission limit expressed as pounds, pounds per hour, or parts per million based on a one-hour or less averaging period or compliance period, compliance shall be based on using data collected at least once every minute when compliance is based on CEMS data. [Rules 69.3, 69.3.1, and 20.3(d)(1)]

28. When a combustion turbine is combusting fuel (operating), the emission concentration of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2), shall not exceed 2.0 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. For purposes of determining compliance based on CEMS data, the following averaging periods calculated in accordance with the CEMS protocol shall apply:

    a. For any transient hour, a 3-clock-hour average, calculated as the average of the transient hour, the clock hour immediately prior to the transient hour and the clock hour immediately following the transient hour.
    b. For all other hours, a 1-clock-hour average.

    [Rule 20.3(d)(1)]

29. When a combustion turbine is operating, the emission concentration of carbon monoxide (CO) shall not exceed 2.0 ppmvd corrected to 15 % oxygen, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. For purposes of determining compliance based on CEMS data, the following averaging periods calculated in accordance with the CEMS protocol shall apply:

    a. For any transient hour, a 3-clock-hour average, calculated as the average of the transient hour, the clock hour immediately prior to the transient hour and the clock hour immediately following the transient hour.
    b. For all other hours, a 1-clock-hour average.

    [Rule 20.3(d)(1)]

30. When a combustion turbine is operating, the volatile organic compound (VOC) concentration, calculated as methane, measured in the exhaust stack, shall not exceed 1.5 ppmvd corrected to 15% oxygen, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. For purposes of determining compliance based on the CEMS, the District approved CO/VOC surrogate relationship, the CO CEMS data, and the following averaging periods calculated in accordance with the CEMS protocol shall be used:

    a. For any transient hour, a 3-clock-hour average, calculated as the average of the transient hour, the clock hour immediately prior to the transient hour and the clock hour immediately following the transient hour.
    b. For all other hours, a 1-clock-hour average.

    The CO/VOC surrogate relationship shall be verified and/or modified, if necessary, based on source testing. [Rule 20.3(d)(1)]

31. When a combustion turbine is operating, the ammonia concentration (ammonia slip), shall not exceed 5.0 ppmvd corrected to 15 % oxygen, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. [Rule 1200]

32. When a combustion turbine is operating with post-combustion air pollution control equipment that controls oxides of nitrogen (NOx) emissions, the emission concentration NOx, calculated as nitrogen dioxide (NO_2), shall not exceed 12.9 ppmvd calculated over each clock-hour period and corrected to 15% oxygen, except for periods of startup and shutdown, as defined in Rule 69.3.1. This limit does not apply during any period in which the facility is subject to a variance from the emission limits contained in Rule 69.3.1. [Rule 69.3.1]

33. When a combustion turbine is operating without any post-combustion air pollution control equipment that controls oxides of nitrogen (NOx) emissions, the emission concentration of NOx calculated as nitrogen dioxide (NO_2) from each turbine shall not exceed 21.6 parts per million by volume on a dry basis (ppmvd) calculated over each clock-hour period and corrected to 15% oxygen, except for periods of startup and shutdown, as defined in Rule 69.3.1. This limit does not apply during any period in which the facility is subject to a variance from the emission limits contained in Rule 69.3.1. [Rule 69.3.1]

34. When a combustion turbine is operating, the emission concentration of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2) shall not exceed 42 ppmvd calculated over each clock-hour period and corrected to 15% oxygen, on a dry basis, except during periods of startup and shutdown, as defined in Rule 69.3**.** This limit does not apply during any period in which the facility is subject to a variance from the emission limits contained in Rule 69.3. [Rule 69.3]

35. For each rolling 30-day-unit-operating-day period, average emission concentration of oxides of nitrogen (NOx) for each turbine calculated as nitrogen dioxide (NO_2) in parts per million by volume dry (ppmvd) corrected to 15% oxygen or, alternatively, as elected by the permittee, the average NOx emission rate in pounds per megawatt-hour (lb/MWh) shall not exceed an average emission limit calculated in accordance with 40 CFR Section 60.4380(b)(3). The emission concentration and emission rate averages shall be calculated in accordance with 40 CFR Section 60.4380(b)(1). The average emission concentration limit and emission rate limit shall be based on an average of hourly emission limits over the 30-day-unit-operating-day period. The hourly emission concentration limit and emission rate limit shall be 15 ppmvd corrected to 15% oxygen and 0.43 lb/MWh, respectively, for clock hours when the combustion turbine load is equal to or greater than 156 megawatts at all times during the clock hour, respectively, and 96 ppmvd corrected to 15% oxygen and 4.7 lb/MWh for all other clock hours when the combustion turbine is operating, respectively. The averages shall exclude all clock hours occurring before the Initial Emission Source Test but shall include emissions during all other times that the equipment is operating including, but not limited to, emissions during low load operation, startup, shutdown, and tuning periods. For each six-calendar-month period, emissions in excess of these limits and monitor downtime shall be identified in accordance with 40 CFR Sections 60.4350 and 60.4380(b)(2), except that Section 60.4350(c) shall not apply for identifying periods in excess of a NOx concentration limit, and reported to the District and the federal EPA in accordance with Title V Operating Permit No. 974488. [40 CFR Part 60 Subpart KKKK]

36. The emissions of particulate matter less than or equal to 10 microns in diameter (PM10) shall not exceed 9.5 pounds per hour for each combustion turbine. [Rule 20.3(d)(2)]

37. The discharge of particulate matter from the exhaust stack of each combustion turbine shall not exceed 0.10 grains per dry standard cubic foot (0.23 grams/dscm). The District may require periodic testing to verify compliance with this standard. [Rule 53]

38. Visible emissions from the lube oil vents and the exhaust stack of each combustion turbine shall not exceed 20% opacity for more than three (3) minutes in any period of 60 consecutive minutes. [Rule50]

39. Mass emissions from each combustion turbine of oxides of nitrogen (NOx), calculated as NO_2; carbon monoxide (CO); and volatile organic compounds (VOC), calculated as methane, shall not exceed the following limits, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. A 1-clock-hour averaging period for these limits shall apply to CEMS data except for emissions during transient hours when a 3-clock-hour averaging period shall apply.

Pollutant	Emission Limit, lb
a. NOx	15.1
b. CO	9.2
c. VOC	4.0

[Rule 20.3(d)(2)]

40. Excluding any minutes that are coincident with a shutdown period, cumulative mass emissions of oxides of nitrogen (NOx), calculated as NO_2; carbon monoxide (CO); and volatile organic compounds (VOC), calculated as methane, during a combustion turbine's startup period shall not exceed the following limits during any startup period, except during that turbine's commissioning period.

Pollutant	Emission Limit,lb
a. NOx	69.2
b. CO	545
c. VOC	15.5

[Rule 20.3(d)(1)]

41. Cumulative mass emissions of oxides of nitrogen (NOx), calculated as NO_2; carbon monoxide (CO); and volatile organic compounds (VOC), calculated as methane,during a combustion turbine's shutdown period shall not exceed the following limits during any shutdown period, except during that turbine's commissioning period.

Pollutant	Emission Limit,lb
a. NOx	25.7
b. CO	277
c. VOC	6.2

[Rule 20.3(d)(1)]

42. The oxides of nitrogen (NOx) emissions from each combustion turbine shall not exceed 200 pounds per hour and total aggregate NOx emissions from both combustion turbines combined shall not exceed 286 pounds per hour, calculated as nitrogen dioxide and measured over each 1-clock-hour period. These emission limits shall apply during all times one or both turbines are operating, including, but not limited to, emissions during commissioning, low load operation, startup, shutdown, and tuning periods. [Rule 20.3(d)(2)]

43. The carbon monoxide (CO) emissions from each combustion turbine shall not exceed 3813 pounds per hour and total aggregate CO emissions from both combustion turbines combined shall not exceed 4627 pounds per hour measured over each 1-clock-hour period. This emission limit shall apply during all

times that one or both turbines are operating, including, but not limited to emissions during commissioning, low load operation, startup, shutdown, and tuning periods. [Rule 20.3(d)(2)(i)]

44. Beginning with the earlier of the initial startup dates for either combustion turbine, aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2); carbon monoxide (CO); volatile organic compounds (VOCs), calculated as methane; particulate matter less than or equal to 10 microns in diameter (PM10); and oxides of sulfur (SOx), calculated as sulfur dioxide (SO_2), from the combustion turbines described in District Applications No. 985745 and 985747 and the emergency fire pump described in Application No. 985748, except emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1), shall not exceed the following limits for each rolling 12-calendar-month period:

	Pollutant	Emission Limit, tons per year
a.	NOx	72.11
b.	CO	339.9
c.	VOC	23.7
d.	PM10	39.0
e.	SOx	5.6

In addition, beginning with the date on which both turbines have completed their commissioning periods aggregate emissions of CO and VOC from the equipment specified above in this condition shall not exceed 217.3 and 20.1 tons per year, respectively, for each rolling 12-calendar-month period.

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating including, but not limited to, emissions during commissioning, low load operation, startup, shutdown, and tuning periods. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

45. For each calendar month, the applicant shall maintain records, as applicable, on a calendar monthly basis, of mass emissions during each calendar month of NOx (calculated as NO_2), CO, VOCs (calculated as methane), PM10, and SOx (calculated as SO_2), in tons, from each emission unit described in District Applications No. 985745, 985747, and 985748, except for emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1). These records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

46. For each calendar month and each rolling 12-calendar-month period, the applicant shall maintain records, as applicable, on a calendar monthly basis, of aggregate mass emissions of NOx (calculated as NO_2), CO, VOCs (calculated as methane), PM10, and SOx (calculated as SO_2) in tons for the emission units described in District Applications No. 985745, 985747, and 985748, except for emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1). These records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

47. For each combustion turbine, the number of startup periods occurring in each calendar year shall not exceed 1460. [Rules 1200 and 21]

Ammonia - SCR

48. Not later than 90 calendar days prior to the start of construction, the applicant shall submit to the District the final selection, design parameters and details of the selective catalytic reduction (SCR) and oxidation catalyst emission control systems for the combustion turbines including, but not limited to, the minimum ammonia injection temperature for the SCR; the catalyst volume, space velocity and area velocity at full load with and without steam injection; and control efficiencies of the SCR and the oxidation catalyst CO at temperatures between 100 ºF and 1000 ºF at space velocities corresponding to 100% (with steam injection) and 60% load. Such information may be submitted to the District as trade secret and confidential pursuant to District Rules 175 and 176. [Rules 20.3(d)(1) and 14]

49. When a combustion turbine is operating, ammonia shall be injected at all times that the associated selective catalytic reduction (SCR) system outlet temperature is 450 degrees Fahrenheit or greater. [Rules 20.3(d)(1)]

50. Continuous monitors shall be installed on each SCR system prior to their initial operation to monitor or calculate, and record the ammonia solution injection rate in pounds per hour and the SCR outlet temperature in degrees Fahrenheit for each unit operating minute. The monitors shall be installed, calibrated and maintained in accordance with a District approved protocol, which may be part of the CEMS protocol. This protocol, which shall include the calculation methodology, shall be submitted to the District for written approval at least 90 days prior to initial startup of the gas turbines with the SCR system. The monitors shall be in full operation at all times when the turbine is in operation. [Rules 20.3(d)(1)]

51. Except during periods when the ammonia injection system is being tuned or one or more ammonia injection systems is in manual control for compliance with applicable permit conditions, the automatic ammonia injection system serving the SCR system shall be in operation in accordance with manufacturer's specifications at all times when ammonia is being injected into the SCR system. Manufacturer specifications shall be maintained on site and made available to District personnel upon request. [Rules 20.3(d)(1)]

52. The concentration of ammonia solution used in the ammonia injection system. Shall be less than 20% ammonia by weight. Records of ammonia solution concentration shall be maintained on site and made available to District personnel upon request. [Rule 14]

Testing

53. All source test or other tests required by this permit shall be performed by the District or an independent contractor approved by the District. Unless otherwise specified in this permit or authorized in writing by the District, if testing will be performed by an independent contractor and witnessed by the District, a proposed test protocol shall be submitted to the District for written approval at least 60 days prior to source testing. Additionally, the District shall be notified a minimum of 30 days prior to the test so that observers may be present unless otherwise authorized in writing by the District. [Rules 20.3(d)(1) and 1200 and 40 CFR Part 60 Subpart KKKK and 40 CFR §60.8]

54. Unless otherwise specified in this permit or authorized in writing by the District, within 45 days after completion of a source test or RATA performed by an independent contractor, a final test report shall be submitted to the District for review and approval. [Rules 20.3(d)(1) and 1200 and 40 CFR Part 60 Subpart KKKK, 40 CFR §60.8, and 40 CFR Part 75]

55. The exhaust stacks for each combustion turbine shall be equipped with source test ports and platforms to allow for the measurement and collection of stack gas samples consistent with all approved test protocols. The ports and platforms shall be constructed in accordance with District Method 3A, Figure 2, and approved by the District. Ninety days prior to construction of the turbine stacks the project owner shall provide to the District for written approval detailed plan drawings of the turbine stacks that show the sampling ports and demonstrate compliance with the requirements of this condition. [Rule 20]

56. Not later than 60 calendar days after completion of the commissioning period for each combustion turbine, an Initial Emissions Source Test shall be conducted on that turbine to demonstrate compliance with the NOX, CO, VOC, PM10, and ammonia emission standards of this permit. The source test protocol shall comply with all of the following requirements:

    a. Measurements of NOX and CO concentrations and emissions and oxygen (O_2) concentration shall be conducted in accordance with U.S. Environmental Protection Agency (EPA) methods 7E, 10, and 3A, respectively, and District source test Method 100, or alternative methods approved by the District and EPA;

    b. Measurement of VOC emissions shall be conducted in accordance with EPA Methods 25A and/or 18, or alternative methods approved by the District and EPA;

    c. Measurements of ammonia emissions shall be conducted in accordance with Bay Area Air Quality Management District Method ST-1B or an alternative method approved by the District and EPA;

    d. Measurements of PM10 emissions shall be conducted in accordance with EPA Methods 201A and 202 or alternative methods approved by the District and EPA;

    e. Source testing shall be performed at the normal load level, as specified in 40 CFR Part 75 Appendix A Section 6.5.2.1 (d), provided it is not less than 80% of the combustion turbine's rated load unless it is demonstrated to the satisfaction of the District that the combustion turbine cannot operate under these conditions. If the demonstration is accepted, then emissions source testing shall be performed at the highest achievable continuous power level. The District may specify additional testing at different load levels or operational conditions to ensure compliance with the emission limits of this permit and District Rules and Regulations.

    f. Measurements of particulate matter emissions shall be conducted in accordance with SDAPCD Method 5 or an alternative method approved by the District and EPA; and

    g. Measurements of opacity shall be conducted in accordance with EPA Method 9 or an alternative method approved by the District and EPA

    h. Unless otherwise authorized in writing by the District, testing for NOX, CO, VOC, PM10, and ammonia concentrations and emissions, as applicable, shall be conducted concurrently with the NOx and CO continuous emission measurement system (CEMS) Relative Accuracy Test Audit (RATA).

    [Rules 20.3(d)(1) and 1200]

57. A renewal source test and a NOX and CO Relative Accuracy Test Audit (RATA) shall be periodically conducted on each combustion turbine to demonstrate compliance with the NOX, CO, VOC, PM10, and ammonia emission standards of this permit and applicable relative accuracy requirements for the CEMS systems using District approved methods. The renewal source test and the NOX and CO RATAs shall

be conducted in accordance with the applicable RATA frequency requirements of 40 CFR75, Appendix B, Sections 2.3.1 and 2.3.3. The renewal source test shall be conducted in accordance with a protocol complying with all the applicable requirements of the source test protocol for the Initial Emissions Source Test. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

58. Relative Accuracy Test Audits (RATAs) and all other required certification tests shall be performed and completed on the NOx CEMS in accordance with applicable provisions of 40 CFR Part 75 Appendix A and B and 40 CFR §60.4405 and on the CO CEMS in accordance with applicable provisions of 40 CFR Part 60 Appendix B and F. [Rule 21, Rule 20.3 (d)(1), 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

59. Not later than 60 calendar days after completion of the commissioning period for each combustion turbine, an initial emission source test for toxic air contaminants shall be conducted on that turbine to determine the emissions of toxic air contaminants from the combustion turbines. At a minimum the following compounds shall be tested for, and emissions, if any, quantified:

    a. Acetaldehyde
    b. Acrolein
    c. Benzene
    d. Formaldehyde
    e. Toluene
    f. Xylenes

    This list of compounds may be adjusted by the District based on source test results to ensure compliance with District Rule 1200 is demonstrated. The District may require one or more or additional compounds to be quantified through source testing as needed to ensure compliance with Rule 1200. Within 60 calendar days after completion of a source test performed by an independent contractor, a final test report shall be submitted to the District for review and approval. [Rule 1200]

60. The District may require one or more of the following compounds, or additional compounds, to be quantified through source testing periodically to ensure compliance with rule 1200:

    a. Acetaldehyde
    b. Acrolein
    c. Benzene
    d. Formaldehyde
    e. Toluene
    f. Xylenes

    If the District requires the permittee to perform this source testing, the District shall request the testing in writing a reasonable period of time prior to the testing date. [Rule 1200]

61. The higher heating value of the combustion turbine fuel shall be measured by ASTM D1826–94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter or ASTM D1945–96, Standard Method for Analysis of Natural Gas by Gas Chromatography or an alternative test method approved by the District and EPA. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

62. The sulfur content of the combustion turbine fuel shall be sampled not less than once each calendar quarter in accordance with a protocol approved by the District, which shall be submitted to the District for approval not later than 90 days before the earlier of the initial startup dates for either of the two combustion turbines and measured with ASTM D1072–90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases; ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry; ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry; ASTM D6228–98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection; or ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence or an alternative test method approved by the District and EPA. [Rule 20.3(d)(1), Rule 21, and 40 CFR Part 75]

CONTINUOUS MONITORING

63. The applicant shall comply with the applicable continuous emission monitoring requirements of 40 CFR Part 75. [40 CFR Part 75]

64. A continuous emission monitoring system (CEMS) shall be installed on each combustion turbine and properly maintained and calibrated to measure, calculate, and record the following, in accordance with the District approved CEMS protocol:

    a. Hourly average(s) concentration of oxides of nitrogen (NOX) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the NOx limits of this permit;
    b. Hourly average concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the CO limits of this permit;
    c. Percent oxygen (O_2) in the exhaust gas for each unit operating minute;
    d. Average concentration of oxides of nitrogen (NOX) for each continuous rolling 3-hour period, in parts per million (ppmv) corrected to 15% oxygen;
    e. Hourly mass emissions of oxides of nitrogen (NOX), in pounds;
    f. Cumulative mass emissions of oxides of nitrogen (NOX) in each startup and shutdown period, in pounds;
    g. Daily mass emissions of oxides of nitrogen (NOX), in pounds;
    h. Calendar monthly mass emissions of oxides of nitrogen (NOX), in pounds;
    i. Rolling 30-unit-operating-day average concentration of oxides of nitrogen (NOX) corrected to 15% oxygen, in parts per million (ppmvd);
    j. Rolling 30-unit-operating-day average oxides of nitrogen (NOx) emission rate, in pounds per megawatt-hour (MWh);
    k. Calendar quarter, calendar year, and rolling 12-calendar-month period mass emissions of oxides of nitrogen (NOX), in tons;

l. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds;
m. Hourly mass emissions of carbon monoxide (CO), in pounds;
n. Daily mass emission of carbon monoxide (CO), in pounds;
o. Calendar monthly mass emission of carbon monoxide (CO), in pounds;
p. Rolling 12-calendar-month period mass emission of carbon monoxide (CO), in tons;
q. Average concentration of oxides of nitrogen (NOX) and carbon monoxide (CO)uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), during each unit operating minute;
r. Average emission rate in pounds per hour of oxides of nitrogen (NOX) and carbon monoxide (CO) during each unit operating minute.

[Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

65. No later than 90 calendar days prior to initial startup of each combustion turbine, the applicant shall submit a CEMS protocol to the District, for written approval that shows how the CEMS will be able to meet all District monitoring requirements. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

66. No later than the earlier of 90 unit operating days or 180 calendar days after each combustion turbine commences commercial operation, a Relative Accuracy Test Audit (RATA) and other required certification tests shall be performed an completed on the that turbine's NOx CEMS in accordance with 40 CFR Part 75 Appendix A and on the CO CEMS in accordance with 40 CFR Part 60 Appendix B. The RATAs shall demonstrate that the NOx and CO CEMS comply with the applicable relative accuracy requirements. At least 60 calendar days prior to the test date, the applicant shall submit a test protocol to the District for written approval. Additionally, the District and U.S. EPA shall be notified a minimum of 45 calendar days prior to the test so that observers may be present. Within 45 calendar days of completion of this test, a written test report shall be submitted to the District for approval. For purposes of this condition, commences commercial operation is defined as the first instance when power is sold to the electrical grid. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

67. A monitoring plan in conformance with 40 CFR 75.53 shall be submitted to U.S EPA Region 9 and the District at least 45 calendar days prior to the Relative Accuracy Test Audit (RATA), as required in 40 CFR 75.62. [40 CFR Part 75]

68. The oxides of nitrogen (NOX) and oxygen (O_2) components of the CEMS shall be certified and maintained in accordance with applicable Federal Regulations including the requirements of sections 75.10 and 75.12 of title 40, Code of Federal Regulations Part 75 (40 CFR 75), the performance specifications of appendix A of 40 CFR 75, the quality assurance procedures of Appendix B of 40 CFR 75 and the CEMS protocol approved by the District. The carbon monoxide (CO) components of the CEMS shall be certified and maintained in accordance with 40 CFR 60, Appendices B and F, unless otherwise specified in this permit, and the CEMS protocol approved by the District. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

69. The CEMS shall be in operation in accordance with the District approved CEMs protocol at all times when the turbine is in operation a copy of the District approved CEMS monitoring protocol shall be maintained on site and made available to District personnel upon request. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

70. When the CEMS is not recording data and the combustion turbine is operating, hourly NOx emissions for purposes of calendar year and rolling 12-calendar-month period emission calculations shall be determined in accordance with 40 CFR 75 Subpart C. Additionally, hourly CO emissions for rolling 12-calendar-month period emission calculations shall be determined using CO emission factors to be determined from source test emission factors, recorded CEMS data, and fuel consumption data, in terms of pounds per hour of CO for the gas turbine. Emission calculations used to determine hourly emission rates shall be reviewed and approved by the District, in writing, before the hourly emission rates are incorporated into the CEMS emission data. [Rules 20.3(d)(3) and 21 and 40 CFR Part 75]

71. Any violation of any emission standard as indicated by the CEMS shall be reported to the District's compliance division within 96 hours after such occurrence. [Rule 19.2]

72. The CEMS shall be maintained and operated, and reports submitted, in accordance with the requirements of rule 19.2 Sections (d), (e), (f) (1), (f) (2), (f) (3), (f) (4) and (f) (5), and a CEMS protocol approved by the District. [Rule 19.2]

73. Except for changes that are specified in the initial approved CEMS protocol or a subsequent revision to that protocol that is approved in advance, in writing, by the District, the District shall be notified in writing at least thirty (30) calendar days prior to any planned changes made in the CEMS or Data Acquisition and Handling System (DAHS), including, but not limited to, the programmable logic controller, software which affects the value of data displayed on the CEMS / DAHS monitors with respect to the parameters measured by their respective sensing devices or any planned changes to the software that controls the ammonia flow to the SCR. Unplanned or emergency changes shall be reported within 96 hours. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

74. At least 90 calendar days prior to the Initial Emissions Source Test , the applicant shall submit a monitoring protocol to the District for written approval which shall specify a method of determining the CO/VOC surrogate relationship that shall be used to demonstrate compliance with all VOC emission limits. This protocol can be provided as part of the Initial Source Emissions Test Protocol. [Rule 20.3(d)(1)]

75. Fuel flowmeters shall be installed and maintained to measure the fuel flow rate, corrected for temperature and pressure, to each combustion turbine. Correction factors and constants shall be maintained on site and made available to the District upon request. The fuel flowmeters shall meet the applicable quality assurance requirements of 40 CFR Part 75, Appendix D, and Section 2.1.6. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

76. Each combustion turbine shall be equipped with continuous monitors to measure, calculate, and record unit operating days and hours and the following operational characteristics:

    a. Date and time;
    b. Natural gas flow rate to the combustion turbine during each unit operating minute, in standard cubic feet per hour;
    c. Total heat input to the combustion turbine based the fuels higher heating value during each unit operating minute, in million British thermal units per hour (MMBtu/hr);
    d. Higher heating value of the fuel on an hourly basis, in million British thermal units per standard cubic foot (MMBtu/scf);
    e. Stack exhaust gas temperature during each unit operating minute, in degrees Fahrenheit;

f. Combustion turbine energy output during each unit operating minute in megawatts hours (MWh); and
g. Steam turbine energy output during each unit operating minute in megawatts hours (MWh).

The values of these operational characteristics shall be recorded each unit operating minute. The monitors shall be installed, calibrated, and maintained in accordance with a turbine operation monitoring protocol, which may be part of the CEMS protocol, approved by the District, which shall include any relevant calculation methodologies. The monitors shall be in full operation at all times when the combustion turbine is in operation. Calibration records for the continuous monitors shall be maintained on site and made available to the District upon request. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

77. At least 90 calendar days prior to initial startup of the each combustion turbine, the applicant shall submit a turbine monitoring protocol to the District for written approval. This may be part of the CEMS protocol. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

78. Operating logs or Data Acquisition and Handling System (DAHS) records shall be maintained to record the beginning and end times and durations of all startups, shutdowns, and tuning periods to the nearest minute, quantity of fuel used in each clock hour, calendar month, and 12-calendar-month period in standard cubic feet; hours of operation each day; and hours of operation during each calendar year. For purposes of this condition, the hours of turbine operation is defined as the total minutes the turbine is combusting fuel during the calendar year divided by 60. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Commissioning and Shakedown

79. Before the end of the commissioning period for each combustion turbine, the applicant shall install post-combustion air pollution control equipment on that turbine to minimize NOx and CO emissions. Once installed, the post-combustion air pollution control equipment shall be maintained in good condition and shall be in full operation at all times when the turbine is combusting fuel and the air pollution control equipment is at or above its minimum operating temperature. [Rule 20.3(d)(1)]

80. Thirty calendar days after the end of the commissioning period for each combustion turbine, the applicant shall submit a written progress report to the District. This report shall include, a minimum, the date the commissioning period ended, the periods of startup and shutdown, the emissions of NOx and CO during startup and shutdown, and the emissions of NOx and CO during steady state operation. This report shall also detail any turbine or emission control equipment malfunction, upset, repairs, maintenance, modifications, or replacements affecting emissions of air contaminants that occurred during the commissioning period. All of the following continuous monitoring information shall be reported for each minute and, except for cumulative mass emissions, averaged over each hour of operation:

a. Concentration of oxides of nitrogen (NOX) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);
b. Concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);
c. Percent oxygen (O_2) in the exhaust gas;
d. Mass emissions of oxides of nitrogen (NOX), in pounds;

e. Cumulative mass emissions of oxides of nitrogen (NOX) in each startup and shutdown period, in pounds;
f. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds
g. Mass emissions of carbon monoxide (CO), in pounds;
h. Total heat input to the combustion turbine based on the fuel's higher heating value, in million British thermal units per hour (MMBtu/hr);
i. Higher heating value of the fuel on an hourly basis, in million British thermal units per standard cubic foot (MMBtu/scf);
j. Gross electrical power output of the turbine, in megawatts hours (MWh) for each hour; and
k. SCR outlet temperature, in degrees Fahrenheit; and
l. Stack exhaust gas temperature, in degrees Fahrenheit.

The hourly average information shall be submitted in writing and in an electronic format approved by the District. The minute-by-minute information shall be submitted in an electronic format approved by the District. [Rules 69.3, 69.3.1, 20.3(d)(1)and 20.3(d)(2)]

81. The three utility boilers described on District Permits to Operate No. 791, 792, and 793 shall not operate at any time one or both combustion turbines are operating. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

82. Beginning with the initial startup of Turbine A, aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2); carbon monoxide (CO); volatile organic compounds (VOCs), calculated as methane; particulate matter less than or equal to 10 microns in diameter (PM10); and oxides of sulfur (SOx), calculated as sulfur dioxide (SO_2), from Turbine A and the emergency fire pump described in Application No. 985748, except emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1), shall not exceed the following limits for each rolling 12-calendar-month period:

Pollutant	**Emission Limit, tons per year**
a. NOx	36.05
b. CO	169.95
c. VOC	11.85
d. PM10	19.5
e. SOx	2.8

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating including, but not limited to, emissions during commissioning, low load operation, startup, shutdown, and tuning periods. This condition shall not apply on and after the date Turbine B completes its shakedown period. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

83. Beginning with the date Turbine A completes its shakedown period, aggregate emissions of carbon monoxide (CO); particulate matter less than or equal to 2.5 microns in diameter (PM2.5); and particulate matter less than or equal to 10 microns in diameter (PM10) from the three utility boilers described on District Permits to Operate No. 791, 792, and 793, shall not exceed the following limits for each rolling 12-calendar-month period:

Pollutant	**Emission Limit, tons per year**
a. CO	198.75

b.	PM2.5	21.80
c.	PM10	26.89

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating including, but not limited to, emissions during startup, shutdown, and tuning periods. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

84. On and after the date that Turbine B completes its shakedown period, the three utility boilers described on District Permits to Operate No. 791, 792, and 793 shall not operate. [Rules 20.3(d)(3), 20.3(d)(8) and]

85. For each calendar month and each rolling 12-calendar-month period, the applicant shall maintain records on a calendar monthly basis, of aggregate mass emissions of NOx (calculated as NO_2), CO, and PM10, in tons, for Turbine A and the emergency generator described on Application No. 985748, except for emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1). These records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

86. For each calendar month, the applicant shall maintain records on a calendar monthly basis, of mass emissions during each calendar month of NOx (calculated as NO_2), CO, PM10, and PM2.5, in tons, from each emission unit described on District Permits to Operate No. 791, 792, and 793. These records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

87. For each calendar month and each rolling 12-calendar-month period, the applicant shall maintain records on a calendar monthly basis, of aggregate mass emissions of NOx (calculated as NO_2), CO, PM10, and PM2.5, in tons, for the emission units described in District Permits to Operate No. 791, 792, and 793. These records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

88. No later than 18 months before the initial startup of either combustion turbine, the applicant shall submit an application to the District for a significant Title V permit modification to limit the aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide; carbon monoxide (CO); particulate matter less than or equal to 10 microns in diameter (PM10); and particulate matter less than or equal to 2.5 microns in diameter (PM2.5), from the three utility boilers described on District Permits to Operate No. 791, 792, and 793 in each rolling 12-calendar-month period as specified in this permit. The application shall include a proposed emission calculation protocol to calculate the emissions from each emission unit. Where applicable, this protocol may rely in whole or in part on the CEMS or other monitoring protocols required by this permit. [Rules 20.3(d)(3), 20.3(d)(8), 1410, and 21]

89. For each combustion turbine, the applicant shall submit the following notifications to the District and U. S. EPA, Region IX:

    a. A notification in accordance with 40 CFR Section 60.7(a)(1) delivered or postmarked not later than 30 calendar days after construction has commenced;
    b. A notification in accordance with 40 CFR Section 60.7(a)(3) delivered or postmarked within 15 calendar days after initial startup; and
    c. An Initial Notification in accordance with 40 CFR Section 63.6145(c) and 40 CFR Section 63.9(b)(2) submitted no later than 120 calendar days after the initial startup of the turbine.

In addition, the applicant shall notify the District when: (1) construction is complete by submitting a Construction Completion Notice before operating any unit that is the subject of this permit, (2) each combustion turbine first combusts fuel by submitting a First Fuel Fire Notice within five calendar days of the initial operation of the unit, and (3) each combustion turbine first generates electrical power that is sold by providing written notice within 5 days of this event. [Rules 24 and 21 and 40 CFR Part 75, 40 CFR Part 60 Subpart KKKK, 40 CFR Part §60.7, 40 CFR Part 63 Subpart YYYY, and 40 CFR Part §63.9]

CONDITIONS FOR EMERGENCY FIRE PUMP ENGINE

90. The engine shall be EPA certified to the 2009 model year or later requirements for emergency fire pump engines of 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. [Rule 20.3(d)(1), 40 CFR Part 60 Subpart IIII, and 40 CFR Part 63 Subpart ZZZZ]

91. Engine operation for maintenance and testing purposes shall not exceed 50 hours per calendar year. (ATCM reportable) [Rule 20.3(d)(1) and 17 CCR §93115]

92. The engine shall only use CARB Diesel Fuel. [Rules 20.3(d)(1), 69.4.1, and 17 CCR §93115]

93. Visible emissions including crankcase smoke shall comply with Air Pollution Control District Rule 50. [Rule 50]

94. The equipment described above shall not cause or contribute to public nuisance. [Rule 51]

95. This engine shall not operate for non-emergency use during the following periods, as applicable:

    A. Whenever there is any school sponsored activity, if engine is located on school grounds or
    B. Between 7:30 and 3:30 PM on days when school is in session, if the engine is located within 500 feet of, but not on school grounds.

    This condition shall not apply to an engine located at or near any school grounds that also serve as the student's place of residence. (ATCM reportable) [17 CCR §93115]

96. A non-resettable engine hour meter shall be installed on this engine, maintained in good working order, and used for recording engine operating hours. If a meter is replaced, the Air Pollution Control District's Compliance Division shall be notified in writing within 10 calendar days. The written notification shall include the following information:

    A. Old meter's hour reading.
    B. Replacement meter's manufacturer name, model, and serial number if available and current hour reading on replacement meter.
    C. Copy of receipt of new meter or of installation work order.

    A copy of the meter replacement notification shall be maintained on site and made available to the Air Pollution Control District upon request. [Rule 69.4.1, 17 CCR §93115, and 40 CFR Part 60 Subpart IIII]

97. The owner or operator shall conduct periodic maintenance of this engine and add-on control equipment, if any, as recommended by the engine and control equipment manufacturers or as specified by the engine servicing company's maintenance procedure. The periodic maintenance shall be conducted at least once each calendar year. [Rule 69.4.1]

98. The owner or operator of the engine shall maintain the following records on site for at least the same period of time as the engine to which the records apply is located at the site:

   A. Documentation shall be maintained identifying the fuel as CARB diesel;
   B. Manual of recommended maintenance provided by the manufacturer, or maintenance procedures specified by the engine servicing company; and
   C. Records of annual engine maintenance, including the date the maintenance was performed.

   These records shall be made available to the Air Pollution Control District upon request. [Rule 69.4.1]

99. The owner or operator of this equipment shall maintain a monthly operating log containing, at a minimum, the following:

   A. Dates and times of engine operation, indicating whether the operation was for maintenance and testing purposes or emergency use; and, the nature of the emergency, if known;
   B. Hours of operation for all uses other than those specified above and identification of the nature of that use.

   [Rule 69.4.1 and 17 CCR §93115]

ADDITIONAL TITLE V CONDITIONS

100. The Permittee shall submit to the District and to the federal EPA a compliance certification for the new equipment subject to this permit, in a manner or form approved in writing by the District, within one year of completing construction of that equipment, that includes the identification of each applicable term or condition of the final permit for which the compliance status is being certified, the current compliance status and whether the modified equipment was in continuous or intermittent compliance during the certification period, identification of the applicable permitted method used to determine compliance during the certification period, and any other information required by the District to determine the compliance status. [Rule 1421]

APPENDIX D

EMISSION REDUCTION CREDITS

Summary of Emission Reduction Credits (ERCs) Proposed as Offsets

ERC Certificate No.	Original Issue Date	Type	Pollutant	ERC Amount, tons per year	NOx Equivalent Amount, tons per year	Location of Emission Reductions	Description Emission Reduction	Current Owner
978938-05	6/30/2004	Class A	NOx	35.3	35.3	Naval Air Station—North Island; Foot of Neville Road, Naval Training Center, San Diego; Vesta Street & Ward Road Naval Station San Diego	Permanent shutdown of peaking combustion turbines	Cabrillo Power II, LLC
981518-01	8/01/2006	Class A	NOx	2.3	2.3	3200 Harbor Drive, San Diego	Permanent shutdown of peaking combustion turbines	Cabrillo Power II, LLC
070823-02	11/19/99	Class A	VOCs	5.3	2.65	850 Lagoon Drive, Chula Vista	Shutdown of Vapor Degreasers and Cold Solvent Cleaners	Element Markets, LLC
080212-01	9/22/2006	Class A	VOCs	18.7	9.35	7757 Andrews Avenue, San Diego	Shutdown and restricted operation of wood coating and adhesive application operations	Inland Gas and Electric GP, LLC