PRELIMINARY
DETERMINATION OF COMPLIANCE

CARLSBAD ENERGY CENTER

SAN DIEGO AIR POLLUTION CONTROL DISTRICT
December 12, 2014

Application Numbers

APCD2014-APP-003480	APCD2014-APP-003481
APCD2014-APP-003482	APCD2014-APP-003483
APCD2014-APP-003484	APCD2014-APP-003485
APCD2014-APP-003486	APCD2014-APP-003487

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Fee Schedule:	6 x 20F, 2 x 34H
BEC:	TBD

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1.0 List of Acronyms, Abbreviations, Units and Chemicals

Acronyms and Abbreviations

ACECP – Amended Carlsbad Energy Center Project
APCD – Air Pollution Control District
AQIA – Air quality impact assessment
ATCM – Air toxic control measure
BACT – Best available control technology
BARCT – Best available retrofit control technology
CARB – California Air Resources Board
CCR – Code of California Regulations
CEC – California Energy Commission
CECP – Carlsbad Energy Center Project
CEMS – Continuous emission monitoring system
CFR – Code of Federal Regulations
CTG – Combustion turbine generator
EPA – US Environmental Protection Agency
EPS – Encina Power Station
FDOC – Final determination of compliance
GE – General Electric
GHG – Greenhouse gas
HAP – Hazardous air pollutant
HHI – Health Hazard Index
HHV – Higher heating value
HRA – Health risk assessment
LAER – Lowest achievable emission rate
LHV – Lower heating value
MEIR – Maximum exposed individual resident
MEIW – Maximum exposed individual worker
NESHAP – National Emission Standards for Hazardous Air Pollutants
NFPA – National Fire Protection Association
NSPS – New Source Performance Standards
NSR – New source review
PDOC – Preliminary determination of compliance
PMI – Point of maximum impact
PSD – Prevention of significant deterioration
PTE – Potential to emit
RACT – Reasonably Available Control Technology
RATA – Relative accuracy test audit
RO – Reverse osmosis
SCR – Selective catalytic reduction
SDG&E – San Diego Gas and Electric
SIP – State Implementation Plan
SONGS – San Onofre Nuclear Generating Station

SCAQMD – South Coast Air Quality Management District
TAC – Toxic air contaminant

Chemical Abbreviations

CH_4 - Methane
CO – Carbon monoxide
CO_2 – Carbon Dioxide
N_2O – Nitrous oxide
NH_3 – Ammonia
NMHC – Non-methane hydrocarbons
NOx – Nitrogen oxides
O_2 – Oxygen gas
PM – Particulate matter
PM_{10}, $PM_{2.5}$ – PM with aerodynamic diameter ≤ 10 microns or 2.5 microns, respectively
S – Sulfur
SF_6 – Sulfur hexafluoride
SOx – Sulfur oxides
VOC – Volatile organic compound

Unit Abbreviations

Bhp – Brake horsepower
CO_2e – Carbon dioxide equivalent
ft - Foot
g – Gram
gal - Gallon
gr – Grain
kW - Kilowatt
Lb - Pound
Lb-mol – Pound mole
m - Meter
MMBtu – Million British thermal units
MT – Metric Ton (1 million grams)
MW – Megawatt
SCF – standard cubic foot
ppm – Parts per million
ppmvd – Parts per million by volume, dry conditions
ppmw – Parts per million by weight

2.0 Project Description

Carlsbad Energy Center LLC (the Applicant) proposes to develop a new power plant, the Amended Carlsbad Energy Center Project (Amended CECP or ACECP). The proposed project is an amendment to a previously proposed plant licensed by the CEC and issued an FDOC by the District under District Application Nos. APCD2007-APP-985745, APCD2007-APP-985745, APCD2007-APP-985746, and

APCD2007-APP-985747, hereafter referred to as the "licensed CECP". The proposed plant will have a total net output capacity of 632 MW when operating at average ambient temperature (60.3° F) and will consist of six General Electric LMS 100 PA natural-gas-fired, diffusion-flame turbine engines operating in simple-cycle configuration. When operating at average ambient temperature, each gas turbine will have a maximum gross power output of about 109 MW (105.3 MW net) and maximum heat input of 984 million British thermal units per hour (MMBtu/hr) based on higher heating value of the fuel. These turbines are designed both for efficient operation (up to 44% thermal efficiency) in simple-cycle mode and for fast-starting—capable of reaching 100% load in 10 minutes or less with ramp rates up to 50 MW per minute. The project will also include the installation of two diesel-fired internal combustion engines for emergency use; one engine rated at 327 brake horsepower will drive a water pump to be used for fire-suppression in emergencies, and one engine rated at 779 brake horsepower will drive a generator to produce electrical power in emergency situations.

Each combustion turbine generator (CTG) will be equipped with an inlet air evaporative cooler. Cooling for each turbine is provided by a dry air fin-fan cooler, shell and tube heat exchanger and intercooler between the low and high pressure compressor stages. Each turbine will operate with demineralized water injection to control the formation of pollutants. Emissions from each turbine will be further controlled by the use of exhaust after-treatment consisting of an oxidation catalyst and selective catalytic reduction (SCR) system. The oxidation catalyst is designed to reduce emissions of carbon monoxide (CO), volatile organic compounds (VOC) and various toxic compounds. The SCR system involves the injection of a reductant (ammonia) into the exhaust stream and reaction of this ammonia to reduce emissions of nitrogen oxides (NOx).

The Applicant currently holds a California Energy Commission (CEC) license (07-AFC-06C) to develop a combined-cycle power plant (licensed CECP) at this location. On May 2, 2014, the Applicant submitted an application to the CEC to amend the design of the proposed project to utilize six turbines in simple-cycle configuration instead of the licensed design consisting of two combined-cycle combustion turbines. The Applicant filed applications with the San Diego Air Pollution Control District (District) on May 9, 2014. The applications were deemed incomplete on May 29, 2014. The Applicant submitted a response to the District's request for additional information on June 26, 2014, containing the information necessary to deem the application complete and a second response on July 28, 2014, containing additional information the District requested for efficiently evaluating the application. The application was deemed complete on July 25, 2014. The Amended CECP will replace the licensed CECP if approved. All projects involving proposed power plants with nominal capacity in excess of 50 MW require review by the CEC. The District is required to issue both a preliminary determination of compliance (PDOC) and a final determination of compliance (FDOC). Pursuant to District Rule 20.5 the FDOC review is functionally equivalent to an Authority to Construct review, and FDOC conditions serve as the conditions of the Authority to Construct.

The Amended CECP is to be located north of the intersection of Carlsbad Blvd. and Cannon Road in the city of Carlsbad in San Diego County. Currently, at this location Cabrillo Power I, LLC (both the Applicant and Cabrillo Power I, LLC are subsidiaries of NRG Energy, Inc.) operates the Encina Power Station (EPS), which consists of five natural-gas-fired boilers with a total capacity of approximately 1000 MW plus a 15 MW peaking turbine. After completion of this project, the Applicant has committed to

remove the five existing EPS boilers (EPS Unit Nos. 1–5) and peaking turbine from service and demolish them, along with other structures that support, or did support, the EPS. The licensed CECP proposes removal of EPS Unit Nos. 1–3 once the licensed CECP would be online, whereas the amended project proposes the removal of all existing EPS units including the peaking turbine. The six proposed gas turbines of the Amended CECP will be located on the east side of the current EPS property as seen in figure 2.0-1 of the application submittal.

3.0 Equipment Description

This section contains the technical equipment descriptions for each emission unit that requires a permit to operate from the District.

APCD2014-APP-003480: Emergency diesel engine generator: Caterpillar model C15 ATAAC; S/N TBD; EPA Certified Tier 4i, family ECPXL15.2HZA; 779 bhp rated; turbocharged with charge air cooler and exhaust gas recirculation for emission control; driving a 500 kW generator.

APCD2014-APP-003481: Emergency fire pump diesel engine: John Deere/Clark model JW6H-UFADF0; S/N TBD; EPA certified Tier 3, family EJDXL09.0114; 327 bhp rated at 1760 rpm; turbocharged with charge air cooler for emission control; driving an emergency fire pump.

APCD2014-APP-003482: Unit #6: One nominal 104 MW natural-gas-fired simple-cycle General Electric LMS 100 PA combustion turbine generator with demineralized water injection, S/N TBD; maximum heat input of 984 MMBtu/hr (HHV) at average site-specific ambient conditions; an inlet-air evaporative cooler; combustion turbine exhaust ducted to an oxidation catalyst and selective catalytic reduction (SCR) system with aqueous ammonia injection.

APCD2014-APP-003483: Unit #7: One nominal 104 MW natural–gas-fired simple-cycle General Electric LMS 100 PA combustion turbine generator with demineralized water injection, S/N TBD; maximum heat input of 984 MMBtu/hr (HHV) at average site-specific ambient conditions; an inlet-air evaporative cooler; combustion turbine exhaust ducted to an oxidation catalyst and selective catalytic reduction (SCR) system with aqueous ammonia injection.

APCD2014-APP-003484: Unit #8: One nominal 104 MW natural-gas-fired simple-cycle General Electric LMS 100 PA combustion turbine generator with demineralized water injection, S/N TBD; maximum heat input of 984 MMBtu/hr (HHV) at average site-specific ambient conditions; an inlet-air evaporative cooler; combustion turbine exhaust ducted to an oxidation catalyst and selective catalytic reduction (SCR) system with aqueous ammonia injection.

APCD2014-APP-003485: Unit #9: One nominal 104 MW natural-gas-fired simple-cycle General Electric LMS 100 PA combustion turbine generator with demineralized water injection, S/N TBD; maximum heat input of 984 MMBtu/hr (HHV) at average site-specific ambient conditions; an inlet-air evaporative cooler; combustion turbine exhaust ducted to an oxidation catalyst and selective catalytic reduction (SCR) system with aqueous ammonia injection.

APCD2014-APP-003486: Unit #10: One nominal 104 MW natural-gas-fired simple-cycle General Electric LMS 100 PA combustion turbine generator with demineralized water injection, S/N TBD; maximum heat input of 984 MMBtu/hr (HHV) at average site-specific ambient conditions; an inlet-air evaporative cooler; combustion turbine exhaust ducted to an oxidation catalyst and selective catalytic reduction (SCR) system with aqueous ammonia injection.

APCD2014-APP-003487: Unit #11: One nominal 104 MW natural-gas-fired simple-cycle General Electric LMS 100 PA combustion turbine generator with demineralized water injection, S/N TBD; maximum heat input of 984 MMBtu/hr (HHV) at average site-specific ambient conditions; an inlet-air evaporative cooler; combustion turbine exhaust ducted to an oxidation catalyst and selective catalytic reduction (SCR) system with aqueous ammonia injection.

4.0 Process Description

The proposed Amended CECP will consist of six combustion turbine generators (CTGs), each consisting of an inlet air evaporative cooler; a gas turbine consisting of compressor, combustion, and turbine sections; an intercooler placed between the low and high pressure stages of the compressor section; an oxidation catalyst; and a SCR system. Each combustion turbine will be a General Electric, model LMS 100 PA. Each turbine has a nominal gross output of about 109 MW and net power output of 105.3 MW for a total of 632 MW of net power output for the entire facility. Actual fuel consumption and power output are variable with ambient atmospheric conditions and load level, with the maximum heat input of 984 MMBtu/hr (HHV) occurring at average ambient conditions of 60.3° F and 79.1% relative humidity.

Combustion air for the gas turbine is initially filtered to remove particulates to protect the gas turbine engine interior. When evaporative cooling is enabled, the inlet air is also cooled and densified as it passes through the evaporative cooling section. The air is then drawn through the compressor section of the turbine where the pressure is further increased. The air then passes to the combustion section where natural gas fuel is introduced and combusted, resulting in rapid temperature and pressure increase in the air/gas mixture. Water is also injected directly into the combustion mixture at this stage to minimize flame temperature which reduces NOx production. The exhaust gas then begins to expand as it passes through the turbine section of the engine, which turns a shaft that is attached to a generator for producing electric power.

The exhaust from the gas turbine then passes through the oxidation catalyst and SCR before being vented to the atmosphere. In the oxidation catalyst section, incompletely combusted organic compounds and carbon monoxide are further oxidized on the catalyst and converted primarily to carbon dioxide (CO_2) and water. In the SCR section, aqueous ammonia (NH_3) is introduced into the exhaust stream through lances inserted into the exhaust ducting. The ammonia mixes with the exhaust gas and reacts with NOx on the surface and interior of the catalyst to produce nitrogen gas and water. Some residual ammonia, "ammonia slip", remains in the exhaust gas. Sulfur oxides (SOx) and particulate matter (PM) pollutants are controlled by using natural gas as the fuel source. These pollutants, along with ammonia are released to the atmosphere. The stack of each turbine will be equipped with continuous monitors to measure and record the concentrations of NOx and oxygen (O_2) in the exhaust gas along with monitors to measure and record operational characteristics including natural gas flow rate.

An additional feature of the CTGs is their ability to quickly start and ramp to full load. This is important for air pollution since emissions are typically elevated during these times. The manufacturer estimates that the turbines can reach 100% load within 10 minutes. However, because the oxidation catalyst and SCR catalyst have minimum temperature values below which they are not effective at controlling emissions, it is estimated that for up to 25 minutes after startup the emissions from the turbine will not meet the required emission levels for steady state operation. Based on data provided by the Applicant, acceptable temperature ranges for the SCR catalyst are a minimum of 540° F before ammonia injection can begin and a sustained maximum of 870° F. The catalyst can tolerate intermittent temperature of 932° F with no major detrimental effects. The oxidation catalyst does not have a minimum temperature since no reagents are to be injected, but based on manufacturer data, CO emissions are expected to be controlled at 90% or higher for catalyst temperatures 400° F or higher. VOC emissions are expected to be controlled approximately 40% starting at a catalyst temperature of 400° F increasing to 50% control or more at 750 °F or higher. During normal operations, the turbine exhaust temperature through the catalyst section ranges from about 750 °F to 850 °F. The manufacturer did not provide a maximum temperature for the catalyst, but typical maximums for this type of catalyst are 1250-1350° F to prevent damage to the catalyst. The sustained exhaust gas temperature of the turbines is expected to remain below the sustained high temperature limits for the catalysts.

In addition to the turbine engines, the project will also require the processing of water for use in the water injection system and as makeup water for the evaporative cooler. The project anticipates the primary source of water will be recycled water obtained from the City of Carlsbad. The turbine manufacturer recommends very low dissolved solids content for use in these systems. To achieve this, water will be processed onsite using single stage reverse osmosis (RO). The RO permeate is further processed on-site using an ion exchange process. This demineralized water is then stored for use in the turbine engines. Seawater may also be used as a backup water source, in which case the Applicant will utilize a second stage of RO treatment due to the higher dissolved solids content in raw seawater relative to recycled water.

In addition to the above listed equipment, the project will include natural gas piping and compressors that continuously emit small quantities of air contaminants including VOC due to leaks around fittings, seals, valves, etc. This equipment is included in the emission estimates for the project but is not subject to permitting by the District.

5.0 Emission Estimates

Emissions from this project were calculated as described in the following sections. Emissions for the new equipment were based on the maximum design capacity or other operating conditions reflecting maximum potential emissions including emission limitations established by permit conditions. Emissions were calculated on an hourly, daily and annual basis for criteria pollutants including oxides of nitrogen (NOx), carbon monoxide (CO), volatile organic compounds (VOC), oxides of sulfur (SOx), and particulate emissions with diameter less than or equal to10 microns (PM_{10}) and less than or equal to 2.5 microns ($PM_{2.5}$). Emissions were calculated for the gas turbines operating at multiple load settings and ambient conditions and during startup and shutdown to determine the highest emission rates. Criteria

emissions were also calculated for the emergency and fire pump diesel engines as were VOC emissions due to gas leakage from natural gas piping and compressors. The emissions were used to determine the overall site potential to emit (PTE), for use in the netting analysis (see Section 5.5), and for air quality impact assessment (AQIA) modeling purposes (see Section 6.1).

Actual emissions were also calculated for the shutdown of the existing Encina Power Station (EPS) units. The emissions were calculated on an annual basis for the same criteria pollutants (NOx, CO, VOC, SOx, PM_{10} and $PM_{2.5}$) for each of the years 2009-2013 based on the operating history of the equipment. Calculations were based on continuous emission monitoring system (CEMS) data for NOx for the boilers, annual source test results for CO for the boilers and NOx and CO for the peaking turbine, and standard emission factors for other pollutants. These calculations were used in the netting analysis.

In addition to criteria pollutants, toxic emissions were calculated for the same equipment on an hourly and annual basis. These were used for the health risk assessment (HRA).

For informational purposes only, greenhouse gas (GHG) emissions were also calculated for the proposed new equipment and existing EPS units. Pollutants considered were carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) emitted from combustion sources, fugitive emissions of sulfur hexafluoride (SF_6) from circuit breakers, and CH_4 emissions from natural gas leakage.

5.1 Equations Used

In general, emissions from both the existing and proposed equipment were calculated according to the following methodologies.

Equation 1: Conversion of Emission Limitation or Concentration to Emission Factor

$$EF = \frac{C}{10^6} * \frac{MW}{(385)} * F * \frac{(20.9)}{(20.9 - \%O2)}$$

Where:
EF = Emission Factor (lb/MMBtu);
C = Concentration (ppmvd, given $\%O_2$);
MW = Molecular weight of pollutant;
385 = Molar volume of a pound mole of ideal gas at District standard conditions (scf/lb-mol @ 68F and 1 atm);
F = Dry fuel F-factor (8710 scf/MMBtu for Natural gas, 9190 scf/MMBtu for Diesel)[1];
$20.9/(20.9-\%O_2)$ = Correction factor converting stoichiometric exhaust to specified O_2 content; and
$\%O_2$ = Stack oxygen content (%) at which the concentration is specified;

Equation 2: Emission Calculations

$$E = (EF)(H) = (EF)(Q_f)(\Delta H_c) = (EF)(H_i)(t) = (EF)(Q_{f,i})(\Delta H_c)(t)$$

[1] Table 19-2 of EPA method 19 (www.epa.gov/ttnemc01/promgate/m-19.pdf)

Where:
E = Emissions (lb/time);
EF = Emission factor (lb/MMBtu);
H = Heat input (MMBtu/time);
Q_f = Fuel flow rate (scf/time for natural gas, gallons/time for diesel);
ΔH_c = Fuel heat content (1010 x 10^{-6} MMbtu/scf for natural gas and 0.137 MMbtu/gal for diesel is assumed);
H_i = Heat input (MMBtu/hr);
$Q_{f,i}$ = Fuel flow rate (scf/hr for natural gas, gallons/hr for diesel); and
t = Time scaling factor (hr/day, hr/year, etc.)

Notes: This equation can also be used if the emission factor is given in units of lb/scf natural gas or lb/gallon diesel by omitting the heat content terms and scaling only using fuel consumption. Additionally, a control factor can be applied if it is not accounted for in the emission factor by multiplying E by (100 – η)/100 where η is the control efficiency, in %, achieved by the control device for that pollutant.

Equation 3: Diesel Engine Emission Calculations

$$E = \frac{(EF)_p(P)(t)}{(453.6\frac{g}{lb})}$$

Where:
E = Emissions (lb/time);
EF_p = Power based emission factor (g/bhp-hr);
P = Engine maximum rated power (bhp);
t = Time scaling factor (hr/day), (hr/yr); and
453.6 g/lb = Conversion factor from grams to pounds

Equation 4: Sulfur Dioxide Emission Calculations

(a) $E = \frac{(S_g)}{7000}(Q_{f,i})(t)(\frac{64}{32})$ (b) $E = (\frac{S_d}{10^6})(Q_{f,i})(\rho_d)(t)(\frac{64}{32})$

Where:
E = Emissions of SOx, lb/time;
S_g = Gaseous fuel sulfur content (gr/scf);
7000 = Conversion from grains to lbs (grains/lb);
S_d = Diesel fuel sulfur content (ppmw);
$Q_{f,i}$ = Fuel flow rate (scf/time for natural gas, gal/time for diesel);
t = Time scaling factor (hr/day), (hr/yr);
ρ_d = Diesel fuel density (assume 7.05 lb/gal); and
64/32 = Molecular Wt. ratio of sulfur dioxide (SO_2) to sulfur

Equation 5: Green House Gas Conversion to CO_2 Equivalents

$$E_{CO2e} = (E)(GWP)$$

Where:
E_{CO2e} = GHG emissions in carbon dioxide equivalents (ton CO_{2e}/yr)
E = Emission of the greenhouse gas (ton/yr)
GWP = Global warming potential of the gas (ton CO_{2e}/ton)

5.2 Pre-project Actual Emissions

Pre-project actual emissions from the existing EPS units (Unit Nos. 1–5) and the peaking turbine are summarized in the table below. Note that ammonia, NH_3, is not considered a criteria pollutant and is not regulated by District NSR rules. It is only regulated as a toxic air contaminant by the District. It is included with criteria pollutants in the tables throughout the document for convenience.

Table 1: Pre-project Actual Emissions (ton/yr)

	NOx	CO	VOC	$PM_{10}/PM_{2.5}$	SOx	NH_3
2009	46.96	135.25	24.33	33.63	3.16	3.22
2010	22.08	45.19	11.42	15.81	1.49	2.71
2011	32.29	277.65	17.15	23.71	2.23	4.46
2012	86.71	77.76	45.02	62.29	5.86	17.37
2013	33.11	166.45	16.45	22.80	2.14	4.29

NOx emissions were calculated for the existing boilers, Unit Nos. 1–5, by summing hourly CEMS data provided by the Applicant for each year. NOx emissions for the peaking turbine were calculated from fuel use/heat input data provided by the Applicant for each year multiplied by an emission factor calculated from District source test results using equations 1 and 2 above. CO and NH_3 emissions for the boilers were also calculated using fuel use/heat input data and district source test data and equations 1 and 2. VOC and $PM_{10}/PM_{2.5}$ emissions from the boilers and CO, VOC, $PM_{10}/PM_{2.5}$ from the peaking turbine were also calculated using equation 2, except default emission factors were used[2]. SOx emissions for Units 1-5 and the peaking turbine were calculated assuming a maximum long term fuel sulfur content of 0.25 gr/100 scf and using equation 4. Source test data and fuel data can be seen in the Appendix A. For netting purposes under District NSR rules, calculations are based on the average emissions during the most representative consecutive 2-year period in the previous five years unless such a period cannot be determined. Table 2 below shows averages for each 2-year period for the existing equipment.

[2] Peaker emissions from Table t09 (http://www.sdapcd.org/toxics/emissions/combgas/t09.pdf), Units 1-5 from Table b14 (http://www.sdapcd.org/toxics/emissions/combgas/b13.pdf).

Table 2: 2-Year Averages of Pre-project Actual Annual Emissions (ton/yr)

	NOx	CO	VOC	$PM_{10}/PM_{2.5}$	SOx	NH_3
2009-2010	34.52	90.22	17.87	24.72	2.32	2.96
2010-2011	27.18	161.42	14.29	19.76	1.86	3.59
2011-2012	59.50	177.70	31.09	43.00	4.04	10.92
2012-2013	59.91	122.10	30.73	42.55	4.00	10.83

These calculations do not include any emissions from equipment other than the five boilers and the peaking turbine currently operated at the site.

5.3 Proposed New Gas Turbine Emission Calculations – Normal Operations

Emissions from the gas turbine were estimated for multiple load levels and ambient conditions based on information provided by the manufacturer through the Applicant to determine worst case emissions during steady-state operation. Emissions were also calculated for startup and shutdown operations. The tables below show hourly emissions for each of the operating scenarios considered, and during startup and shutdown operations. The operating and ambient conditions such as fuel input, ambient temperature and relative humidity can be seen in Table 5.1B-2 in the application submittal. Emissions during startup and shutdown operations were calculated separately since emission controls (SCR and oxidation catalysts) do not operate fully during these periods. Startup and shutdown emissions are based on manufacturer estimates for heat input, duration, and emission levels.

Table 3: Emission Rates During Gas Turbine Normal Operations, Emission Stated in lb/hr

Operating Scenario	Heat Input, HHV (MMBtu/hr)	NOx	CO	VOC	SOx (short term)	SOx (long term)	NH_3	PM_{10}[3]	$PM_{2.5}$
Cold, 100% Load	969	8.93	8.70	2.48	2.04	0.68	6.60	5.0	5.0
Cold, 25% Load	377	3.47	3.38	0.97	0.79	0.26	2.57	5.0	5.0
Hot, 100% Load, Evap	908	8.37	8.15	2.33	1.91	0.64	6.19	5.0	5.0
Hot, 100% Load, No Evap	881	8.12	7.91	2.26	1.85	0.62	6.00	5.0	5.0
Hot, 25% Load	352	3.24	3.16	0.90	0.74	0.25	2.40	5.0	5.0
Avg., 100% Load, Evap	982	9.05	8.81	2.52	2.06	0.69	6.69	5.0	5.0
Avg., 100% Load, No Evap	984	9.07	8.83	2.52	2.07	0.69	6.70	5.0	5.0
Avg., 50% Load	377	3.47	3.38	0.97	0.79	0.26	2.57	5.0	5.0
Maximum	**984**	**9.07**	**8.83**	**2.52**	**2.07**	**0.69**	**6.70**	**5.0**	**5.0**

Heat inputs in the above table came from Table 5.1B-2 in the application submittal. The calculations reflect proposed permit conditions that limit NOx to 2.5 ppmvd at 15% O_2, CO to 4 ppmvd at 15% O_2, VOC limited to 2 ppmvd at 15% O_2, and ammonia (NH_3) slip to 5 ppmvd at 15% O_2. Equations 1 and 2

[3] PM_{10} and $PM_{2.5}$ emissions of 5 lb/hr shown are based on the maximum emissions of a single turbine over a single hour. Emissions averaged for all six turbines over each year are estimated at a lower average level of 3.5 lb/hr.

above were used to calculate emissions in lb/hr from these values. PM_{10} and $PM_{2.5}$ emissions are assumed to be the equal, and reflect proposed permit conditions that limit maximum emissions to 5.0 lb/hr or less for any one turbine. SO_2 short term (24 hours or less) is based on PUC natural gas limit of 0.75 gr S/100 scf natural gas as a short term maximum rate and the long term is based on 0.25 gr S/100 scf as a long term average for pipeline quality gas.

Table 4: Gas Turbine Emissions During Startup and Shutdown, lb/event

Operating Mode	Duration (mins)	Fuel (MMBtu - HHV)	NOx	CO	VOC	SOx (short)	SOx (long)	PM_{10}	$PM_{2.5}$
Startup	25	293.57	14.7	7.4	2.0	0.617	0.206	2.08	2.08
Shutdown	13	48.63	0.6	3.4	2.4	0.102	0.0341	1.08	1.08
Startup + Shutdown + Max SS[a]	60	703	18.6	14.0	5.3	1.5	0.5	5.0	5.0
Startup + Shutdown + Startup	60	600.54	28.2	17.3	6.16	1.26	0.42	5.0	5.0
Shutdown + Startup + Max SS[a] + Shutdown	60	538.43	17.3	15.5	7.2	1.03	0.377	5.0	5.0

[a]Max SS indicates operating at steady state at the maximum normal operation emission rate for the balance of the hour.

The durations and fuel inputs were provided by the Applicant in Table 5.2B-4 of the application submittal. SO_2 and PM_{10} emissions are assumed to be the same as during normal operations since they do not depend on emission controls. Sulfur emissions are based on the same sulfur contents used for normal operations and use the fuel input listed in Table 4. Since a single startup and shutdown do not last an hour, and these turbines are expected to operate for peaking power, it is possible multiple startups and shutdowns could occur within an hour. For this reason, the table above also estimates emissions for an hour where the turbine starts up (25 minutes), operates at the maximum steady state emission level for 22 minutes as shown in Table 3 (so emissions in pounds for this period are 22/60 x max emission rate in Table 3), and then shuts down for the remaining 13 minutes in the hour. Emissions during each mode were then summed for the hour. This same procedure was followed for an hour where the turbine operationally starts up, shuts down and begins to start up again (only completes 22/25 mins of the second startup); and for an hour where it shuts down, starts up, runs at the maximum load for 9 minutes, then completes a shutdown. Emissions are highest for all pollutants except for VOC during the startup, shutdown, startup hour, and highest for VOC during the shutdown, startup, steady state, shutdown hour.

Finally, based on the proposed permit limit of 2700 hours per year per turbine engine, and assumption of 4 startups and shutdowns each day, and 400 total startups and shutdowns each year, maximum PTE was calculated on an hourly, daily, and annual basis for each pollutant. These are shown in the table below.

Table 5: Gas Turbine PTE

Hourly Emissions (lb/hr)							
Emitting Unit	NOx	CO	VOC	SOx (short)	PM_{10}	$PM_{2.5}$	NH_3
One Turbine	28.2	17.3	7.2	2.07	5.0	5.0	6.70
Six Turbines	169.4	103.9	43.1	12.4	30.0	30.0	40.2
Daily Emissions (lb/day)							
	NOx	CO	VOC	SOx (short)	PM_{10}	$PM_{2.5}$	NH_3
One Turbine	255.9	232.8	71.8	49.6	120	120	160.9
Six Turbines	1535.2	1396.8	430.6	297.9	720	720	965.2
Annual Emissions (ton/yr)							
	NOx	CO	VOC	SOx (long)	PM_{10}	$PM_{2.5}$	NH_3
One Turbine	14.15	12.96	3.97	0.93	4.7	4.7	9.0
Six Turbines	84.9	77.8	23.8	5.6	28.4	28.4	54.3

These calculations assume all turbine engines may go through startup/shutdown simultaneously. Emission concentrations and other assumptions are as previously listed for calculations in Tables 3 and 4. These calculations do not take into account emissions during commissioning events or any plant-wide emission limits that may be used to limit PTE below these levels.

5.4 Other Proposed New Equipment Emission Calculations

Other relevant proposed new sources of pollutants at this facility include the emergency and fire pump diesel engines, gas leakage from natural gas handling equipment. Emissions from the two diesel engines were calculated and can be seen in the following table.

Table 6: PTE for Emergency Generator and Fire pump Engines

	Emergency Engine Only			**Fire pump Engine Only**			**Two Engines Combined**		
	lb/hr	**lb/day**	**ton/yr**	**lb/hr**	**lb/day**	**ton/yr**	**lb/hr**	**lb/day**	**ton/yr**
NOx	3.84	3.84	0.096	1.87	1.87	0.047	5.72	5.72	0.14
CO	1.15	1.15	0.029	0.505	0.505	0.013	1.66	1.66	0.04
NMHC/VOC	0.13	0.13	0.003	0.072	0.072	0.002	0.20	0.20	0.01
PM	0.09	0.09	0.002	0.079	0.079	0.002	0.17	0.17	0.0042
SO_2	0.01	0.01	0.0002	0.003	0.003	0.0001	0.01	0.01	0.0003

The emissions in the above table were calculated according to equation 3 for pollutants except SOx, and according to equation 4(b) for diesel. A fuel density of 7.05 lb/gal and sulfur content of 15 ppmw for CARB diesel were assumed. Emissions were calculated using the weighted emission factors provided by the Applicant in attachment 7 to the incomplete letter response. The emergency engine is rated at 779 bhp with maximum fuel use of 35.9 gal/hr and the fire pump engine is rated at 327 bhp with maximum fuel use of 14.8 gal/hr. The calculations assume the engines may operate simultaneously. Hourly emissions assume full load for the entire hour, daily emissions assume 1 hr of operation per day, and annual emissions assume 50 hours of operation per year – the limit for nonemergency use of emergency engines. Emissions from emergency use are highly variable and not included in these calculations.

Fugitive emissions from natural gas handling (pipes, compressors, etc.) were also calculated. These emissions include both non-VOC organics (e.g., methane) and VOC.

Table 7: Fugitive Emissions from Natural Gas Leakage

			VOC Emissions			CH_4 Emissions		
Source	**No. Units**	**EF (kg TOC/hr/unit)**	**lb/hr**	**lb/day**	**ton/yr**	**lb/hr**	**lb/day**	**ton/yr**
Valves	50	4.50E-03	0.047	1.12	0.21	0.45	10.8	1.98
Connectors	112	2.00E-04	0.0047	0.11	0.020	0.045	1.08	0.20
Compressors	3	8.80E-03	0.0055	0.13	0.024	0.053	1.27	0.23
Total			0.057	1.37	0.250	0.55	13.2	2.41

These emissions were calculated using the emission factors and procedure in Table 2-4 of "Protocol for Equipment Leak Emission Estimates"[4]. This procedure calculates total organic emissions and is based on constant emission rates per emission point rather than being based on a percent of gas throughput. The number of units is multiplied by the emission factor, and the units are assumed to be operating every hour to calculate daily and annual emissions. VOCs are assumed to make up 9.56% by weight of organic emissions based on gas composition specified by the District in Pio Pico Energy center evaluation as a conservative value for natural gas derived from liquefied natural gas (LNG). Methane emissions are based on an estimated 91.2% by weight estimate for site-specific gas. (Note that these sum to greater than 100% since both are meant to be individually conservative).

5.5 Post-Project Total Site Criteria Emissions and Net Emission Increase

Total criteria pollutant and ammonia emissions were summed for the site and are listed in the tables below to establish the overall site post-project PTE on an hourly, daily and annual basis. This calculation assumes all equipment operates simultaneously under the operating conditions previously described for hourly and daily emissions.

Table 8: Total Site PTE for Proposed New Equipment (lb/hr)

	NOx	**CO**	**VOC**	**SOx**	**PM_{10}**	**$PM_{2.5}$**	**NH_3**
Turbines	169.4	103.9	43.1	12.4	30.0	30.0	40.2
Engines	5.72	1.66	0.20	0.01	0.17	0.17	0
Compressors	0	0	0.057	0	0	0	0
Total	175.1	105.5	43.3	12.4	30.2	30.2	40.2

Table 9: Total Site PTE for Proposed New Equipment (lb/day)

	NOx	**CO**	**VOC**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**NH_3**
Turbines	1535	1396.8	430.6	298	720	720	965.2
Engines	5.72	1.66	0.20	0.01	0.17	0.17	0
Compressors	0	0	1.37	0	0	0	0
Total	1541	1398.4	432.2	298	720.2	720.2	965.2

[4]Protocol for Equipment Leak Emission Estimates, US EPA, 1995. (www.epa.gov/ttnchie1/efdocs/equiplks.pdf.)

Table 10: Total Site PTE for Proposed New Equipment (ton/yr)

	NOx	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$	NH_3
Turbines	84.92	77.79	23.80	5.59	28.35	28.35	54.3
Engines	0.14	0.04	0.01	0.0003	0.004	0.004	0
Compressors	0	0	0.25	0	0	0	0
Total	85.07	77.83	24.06	5.59	28.35	28.35	54.29

The net annual emission increase for this project is the post-project PTE minus the most representative pre-project actual emissions (baseline emissions) for those emission units proposed to be shutdown – the five boilers and the peaking turbine. Based on review of emissions data, the District preliminarily determined that the average annual emissions during the most recent two calendar years (2012-2013) in the past five years (see Table 2) are the most representative for calculating the net emission increase (or decrease) because they reflect operation after the San Onofre Nuclear Generation Station ceased producing power. The table below calculates the emission increase from this project.

Table 11: Determination of Net Emission Increase from Proposed Project

	NOx	CO	VOC	SOx	PM_{10}	$PM_{2.5}$	NH_3
Post-project PTE	85.07	77.83	24.06	5.59	28.35	28.35	54.29
Post-project PTE with NOx limit	84.8	77.83	24.06	5.59	28.35	28.35	54.29
Baseline emissions	59.91	122.1	30.73	4.00	42.55	42.55	10.83
Net increase	**24.89**	**-44.27**	**-6.67**	**1.59**	**-14.20**	**-14.20**	**43.46**

Based on this calculation the project will result in an emission decrease for CO, VOC and PM_{10}. It will result in an increase of NOx, SO_2 and NH_3. This calculation includes an additional annual limit for NOx for the new equipment as a whole and the existing boilers and peaking turbine accepted by the Applicant to ensure the emission increase stays below 25 tons/yr. Additional annual emission limits are included in the proposed permit conditions for the other criteria pollutants to ensure that the post-project PTE and, therefore, the net emission increase do not exceed the values listed in Table 11. Note that lead is not included, even though it is a criteria pollutant, since no significant lead emissions are expected from the source. Also, as previously noted, ammonia is not a criteria pollutant nor regulated by District NSR rules so there is no explicit annual emission limit for ammonia (there is a limit on ammonia concentration in the turbine exhaust that, in effect, limits hourly and annual ammonia emissions from the new turbines). Additionally for informational purposes only, the District calculated a net emission increase for greenhouse gas emissions and these calculations can be seen in section 5.9 below.

5.6 Non-Criteria Pollutant Emission Calculations (HAPs and TACs)

Emissions of toxic air pollutants were also calculated for the proposed gas turbines and diesel engines. For the gas turbines, emissions were calculated using a combination of standard emission factors from District sources[5], and the state CATEF database[6]. Ammonia emissions were calculated based on the

[5] http://www.sdapcd.org/toxics/emissions/combgas/t10.pdf.
[6] http://www.arb.ca.gov/ei/catef/catef.htm

procedures previously described assuming an ammonia slip of 5 ppmvd @ 15% O_2, which is the maximum allowed in the proposed permit conditions. Emissions were calculated for both the initial/commissioning year and for normal years. During normal operations a control efficiency for all toxic air pollutants, except ammonia, of 50 % was assumed based on standard District policy for oxidation catalyst control efficiency for VOCs. During startup and shutdown, emissions were scaled up according to the ratio of VOC emissions during the highest startup and shutdown hour (see Section 4.4) compared to VOC emissions at 100% load (a ratio of 2.84). During commissioning, it was assumed that emissions would be the same as uncontrolled emissions at 100% load since the emission controls may not be functioning during commissioning.

Toxic emissions were also calculated for metals potentially contained in the injection water used to control NOx emissions from the turbines. This was done by multiplying the maximum hourly water usage for the injection system by the metals concentrations expected in the water, conservatively assuming no removal through the demineralization process. These calculations are presented in Tables A-8 and A-9 of Appendix A.

5.7 Commissioning Emission Estimates

Each gas turbine must be operated for a limited duration during initial installation without emission controls or with the emissions controls not functioning or not with the controls operating at reduced effectiveness and at a variety of load steps. The Applicant estimates that this will require a maximum of 213 hours of operation per turbine, broken down into 12 unfired hours, 90 hours with no controls, 23 hours of tuning the controls, and 88 hours of base load and reliability testing with controls functional[7]. Based on expected load levels and durations for each mode of the test, emissions were estimated by the manufacturer. These calculations can be seen in Table 5.1B-5 of the application submittal. Annual commissioning emissions do not need to be added to the PTE since proposed permit conditions will require that emissions not exceed the annual PTE for normal operations during the commissioning year.

5.8 Comparison to Licensed CECP

For informational purposes only, the District compared emissions from the proposed ACECP to the licensed CECP. Emissions for the licensed CECP were obtained from Table 3a of the FDOC issued by the District. Emissions for the ACECP are from Table 10 of this report. These numbers do not include any emissions or proposed emission decreases from the existing EPS units.

Table 12: Comparison of Emissions for Licensed and Amended CECP

	NOx	CO	VOC	SOx	(PM_{10})	($PM_{2.5}$)
Licensed	75.6	217.3	20.05	16.9	39	39
Amended	84.8	77.8	24.1	5.6	28.4	28.4
Increase	9.2	-139.5	4.0	-11.3	-10.6	-10.6

[7] See Table 5.1B-5 of the Applicant submittal

5.9 Green House Gas (GHG) Emission Calculations

For informational purposes only, greenhouse gas emissions were also calculated for all proposed new equipment. Greenhouse gases emitted by this equipment include carbon dioxide (CO_2), nitrous oxide (N_2O) and methane (CH_4) emitted by the gas turbines, CO_2 emitted by the emergency diesel engines, methane leakage from natural gas compressors and fittings and sulfur hexafluoride (SF_6) leakage from circuit breakers. Emissions from the turbines, engines and natural gas compressors were calculated using the same procedures as for criteria pollutants, except using emission factors for each GHG. Emissions of SF_6 were calculated using the procedure outlined in Table 5.1B-19 of the application submittal, assuming a leakage rate of 0.5%/year of all SF_6 contained in each of the eight circuit breakers. These emissions were then converted to carbon dioxide equivalents (CO_2e) using global warming potentials listed by EPA[8]. Greenhouse gas emissions were also calculated for the existing equipment during years 2012-2013 and compared to existing emissions to determine the increase in GHG emissions. The table below lists GHG emission calculations for the entire facility. Detailed results of the calculations for each category of equipment can be seen in the appendices.

Table 13: Estimated GHG Emissions for the Proposed Project

	US Tons CO_2e/yr	Metric Tons CO_2e/yr
Turbines	933317.5	846692.4
Engines	28.4	25.8
Compressors	60.2	54.7
Breakers	135.7	123.3
Total	933541.7	846896.2
Existing baseline	662406.6	600925.8
Net increase	271135.2	245970.4

6.0 Rules Analysis

6.1 District PSD and NSR Rules

Rule 20.1(c)(16): Contemporaneous Emission Increase

The contemporaneous emission increase as defined in District Rule 20.1(c)(16) is calculated by summing the increases in emissions occurring within the four calendar years preceding the date the proposed project commences operation and the calendar year the project is expected to commence operation, for a total of 5 years. These emission increases may be reduced by actual emission reduction calculations pursuant to 20.1(d)(4). In this case, the Applicant is proposing to create actual emission reductions by replacing the operations of, and shutting down, the existing the existing peaking turbine with District Permit No. APCD2003-PTO-001267 and the five existing utility boilers, Units 1, 2, 3, 4, and 5 with

[8] GHG emission rates and global warming potentials. 40 CFR 98 subparts A and C, tables A-1, C-1, C-2.

District permit Nos. APCD2003-PTO-000791, APCD2003-PTO-000792, APCD2003-PTO-000793, APCD2003-PTO-001770 and APCD2003-PTO-005238, respectively.

This project is expected to begin operation in 2017, so the dates of interest are calendar years 2013-2017 for determining the contemporaneous emission increases. Aside from the licensed CECP, no applications have been filed and/or implemented that result or may result in emission increases during the subject period. The proposed permit conditions contain provisions that prohibit the construction or operation of both the licensed CECP and ACECP. Hence, the contemporaneous increase from the licensed CECP is not considered in the contemporaneous increase for the ACECP.

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. 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 new equipment could proceed in parallel or sequentially.

After completion of the project including reaching full commercial operation of all the proposed new combustion turbines, the electrical generating capacity intended to be replaced that was previously supplied by the existing EPS units will have been replaced by the generating capacity of the new units.

All emission increases from the proposed new equipment related to the ACECP along with emission reductions from shutdown of the existing EPS units have been included in the calculation of emission increase listed in Table 11 in the Section 5. Furthermore, proposed permit conditions will limit emissions of each air contaminant from the existing equipment (EPS units 1–5 and the peaking turbine), as necessary to prevent exceeding either the nonattainment NSR major modification or PSD modification thresholds (see below), on a tiered basis depending on the startup date for each proposed new turbine to ensure that actual emission reductions are obtained at the end of each 180-day shakedown period. The net emission increase (or decrease) listed in Table 11 is the contemporaneous emission increase for the project after the end of the 6th new turbine's shakedown period.

<u>Rule 20.1(c)(35), 20.1(c)(33): Major Stationary Source and Major Modification</u>

A major stationary source as defined in District Rule 20.1 is any emission unit or stationary source that has or will have after issuance of a permit an aggregate PTE in excess of any of the following limits for each of the corresponding pollutants: PM_{10} – 100 tons per year; NOx – 50 tons per year; VOC – 50 tons per year; SOx – 100 tons per year; CO – 100 tons per year; Lead – 100 tons per year. Emissions from the existing EPS units (see Table 1 in Section 5) exceed these levels for NOx and CO, and PTE of the proposed ACECP as shown in Table 10 will exceed these levels for NOx only. The stationary source is therefore an existing major source and will still be a major source after implementation of the ACECP project as proposed.

A major modification is defined in District Rule 20.1 as a physical or operational change which results or may result in a contemporaneous emission increase at an existing major source in excess of the following limits for each of the corresponding pollutants: PM_{10} – 15 tons per year; NOx – 25 tons per year; VOC – 25 tons per year; SOx – 40 tons per year; CO – 100 tons per year; Lead – 0.6 tons per year. Proposed permit conditions contain an annual emission limits covering the ACECP and the existing boilers and peaking turbine that limits total NOx emissions from this equipment to 84.8 tons of NOx per year, which ensures that the contemporaneous emission increase of NOx does not exceed 25 tons per year, and that limit the potential increase for other pollutants so that emissions of these pollutants do not exceed any of the applicable NSR or PSD modification thresholds (see PSD below). Therefore, the project is not a major modification for any pollutant.

It should be noted that, although the District fully expects the boilers and peaking turbine of the EPS to be shut down and demolished, the proposed permit conditions do not require this; however, they do require that emissions from the existing units reach zero tons of NOx per year once the shakedown period for all six proposed new turbines has ended.

Rule 20.1(c)(58): Prevention of Significant Deterioration (PSD) Stationary Source and PSD Modifications

The district is not currently authorized to implement the Federal PSD program by EPA. However, District Rule 20.3 contains similar provisions implemented by the District on a local basis (with the notable exceptions of GHGs and $PM_{2.5}$— $PM_{2.5}$ is in effect regulated as a subset of PM_{10} under the District rule). The District did adopt Rule 20.3.1 on April 4,2012, which would incorporate the federal PSD program as it existed on the date of adoption into District rules. But, due to recent court decisions that vacated portions of the PSD program as it existed in 2012, the fate of Rule 20.3.1 is uncertain. The EPA has not approved the rule, which is a required step before it becomes effective, so the rule is not currently in effect and would not be in effect absent EPA approval.

A PSD stationary source is defined by Rule 20.1 as any stationary source that has or will have after issuance of a permit an aggregate PTE in excess of limits that depend on the type of stationary source. If the facility is classified as a "fossil fuel fired steam electrical plant of more than 250 MMBtu/hr heat input", those limits are 100 ton/yr of any of the following pollutants: PM_{10}, NOx, VOC, SOx, CO. If the facility is not classified this way (there are other source categories listed in Table 20.1-11 subject to the 100 ton/yr limits, but they are not relevant to this discussion), the limits are a PTE in excess of 250 ton/yr for any of these same pollutants. Prior to retirement of the EPS boilers, this facility is a steam generating electrical plant, and, therefore, subject to the 100 ton/yr limits, meaning it is a PSD source due to actual CO emissions alone as seen in Table 1 in Section 5.2. It would also be a PSD source of NOx, VOCs and PM_{10} based on PTE. After retirement of the EPS boilers, it would no longer be classified as a steam generating electrical plant. In any event, provided the proposed annual emission limits for criteria pollutants for the ACECP are complied with, the facility would also not have emissions in excess of either set of trigger levels.

Under District rules, a PSD modification means a contemporaneous emissions increase occurring at a modified PSD stationary source equal to or greater than any of the following levels: PM_{10} – 15 tons per year; NOx – 40 tons per year; VOC – 40 tons per year; SOx – 40 tons per year; CO – 100 tons per year;

and lead – 0.6 tons per year. Regardless of whether this source is considered a modified PSD stationary source, the contemporaneous emission increases do not exceed any of these levels, so this project is not a PSD modification.

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

As a modification of an existing major stationary source, this project and the installation of the new emission units are potentially subject to the BACT and LAER requirements of Rule 20.3(d)(1). BACT is required for any new emission unit with a potential to emit greater than or equal to 10 lb/day of NOx, VOC, PM_{10}, or SOx. The PTE of the combustion turbines exceed this threshold for each pollutant, so BACT is required for NOx, VOC, PM_{10}, and SOx. Emissions from the emergency and fire pump engines do not exceed these levels for any pollutants, so BACT is not required for the diesel engines for NOx, VOC, PM_{10}, or SOx. Since the project emission increase is not a PSD modification and none of the emission units by themselves constitute a new PSD stationary source of CO (see Tables 5, 6, and 7), BACT is not required for CO.

LAER is applicable only to federal nonattainment pollutants or their precursors. For the District, the only nonattainment pollutants are NOx and VOCs which are precursors for ozone for which the District is in nonattainment of the federal 8-hour ambient air quality standard. At existing major sources, LAER is applicable to projects that have a contemporaneous emission increase equal to or greater than 25 tons per year, which constitutes a major modification under District NSR rules, or to emission units with an emission increase that constitute a new major source by themselves. The proposed project emission increase is not a major modification for NOx or VOCs, and the emission increase from each new emission unit does not constitute a major stationary source of NOx or VOCs by itself (see Tables 5, 6, and 7). Hence, none of the emission units are subject to the LAER requirements of 20.3(d)(v).

BACT is defined in District Rule 20.1(c)(11) as the lowest emitting of: (1) the most stringent emission limitation or most effective emission control device or control technique, proven in field application and which is cost effective unless it is demonstrated to not be technologically feasible, (2) any emission limitation or control device/technique not proven in field application which is cost effective and technologically feasible, (3) any control equipment, process modification, change in fuels or substitution of equipment or process determined by the District to be technologically feasible and cost effective, including technology transfers from other source categories, (4) the most stringent emission limitation or most effective control device contained in any state implementation plan approved by EPA unless demonstrated to be technologically infeasible or not cost effective. The BACT determination for each pollutant for which it is required is discussed below:

NOx:

The simple-cycle gas turbines are subject to BACT requirements for NOx. The Applicant has proposed a steady-state, controlled emission level of 2.5 ppmvd corrected to 15% O_2 and averaged over each operating hour. This is achieved using a combination of water injection and SCR with ammonia injection. To support this conclusion the Applicant submitted a top-down BACT analysis. This analysis identified

the only emission limit lower than this achieved for a combustion turbine is 2.0 ppmvd NOx corrected to 15% O_2 for a combined-cycle unit.

Recent permitting decisions by the District and other agencies were reviewed to confirm this as the BACT emission level. Recent permits issued by the District for simple-cycle units include a 48.5 MW combustion turbine (Escondido Energy Center), a 49.95 MW combustion turbine (El Cajon Energy), and two 49.8 MW combustion turbines (Orange Grove Energy), all of which were permitted at 2.5 ppmvd @ 15% O_2 averaged over one-hour. The District has also issued an FDOC for the Pio Pico Energy center which would include 3 GE LMS 100 PA turbines similar to those proposed for this project that was permitted with a limit of 2.5 ppmvd NOx at 15% O_2 averaged over one hour. The District has also permitted two combined-cycle plants (Otay Mesa Energy Center and Palomar Energy Center) that are limited to 2.0 ppmvd NOx at 15% O_2 averaged over one hour. Additionally, both the Walnut Creek Energy Park licensed by CEC and operational as of 5/1/2013 and the Panoche Energy Center licensed by the CEC and operational as of 7/1/2009 include similar LMS100 turbines permitted with limits of 2.5 ppmvd NOx at 15% O_2 averaged over one hour.

Review of ARB/EPA BACT clearinghouses did not find any emission limits lower than these. The lowest emission limits found in the ARB database were for the same plants as listed above. The EPA database did not have any lower emission limits for simple-cycle turbines. For combined-cycle turbines, the EPA database listed 2.0 ppmvd @ 15% O_2 as the lowest emission rate (Marshalltown Generating Station, two approx. 300 MW Siemens SGT6-5000F gas turbines). South Coast Air Quality Management District (SCAQMD) has also issued an FDOC for the CPV Sentinel plant[9] which is now operating utilizing similar GE LMS 100 PA combustion turbines, which has an emission limit of 2.5 ppmvd NOx at 15% O_2 averaged over one hour.

Based on a review of these permit decisions, although considered NOx BACT for natural-gas-fired combined-cycle turbines, the District found no evidence that a limit of 2.0 ppmvd @ 15% O_2 has been demonstrated feasible for simple-cycle units to continuously comply with using SCR. Moreover, alternative control devices such as XONON combustors or EMx catalyst have not been demonstrated to be capable of meeting a NOx emission limit lower than 2.5 ppmvd corrected to 15% O_2 for simple-cycle turbines of this size (> 50 MW).

Based on the above, the District concurs with the Applicant that a NOx emission limit of 2.5 ppmvd corrected to 15% O_2 and averaged over each operating hour is BACT for this air contaminant for the combustion turbines. This limit is the lowest achieved in practice for the use of SCR with a simple-cycle unit. Proposed permit conditions require monitoring of NOx emissions with a CEMS along with monitoring of fuel flow rate and ammonia injection rate to ensure continuous compliance.

NOx emissions during non-steady state conditions (startup, shutdown, and commissioning) are addressed in the startup and shutdown and commissioning section below.

<u>VOC:</u>

[9] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=07-AFC-03.

The simple-cycle gas turbines are subject to BACT requirements for VOC. The Applicant has proposed an emission limit of 2.0 ppmvd corrected to 15% O_2 and averaged over each operating hour, achieved through the use of natural gas fuel and an oxidation catalyst. This is the only known combination of technologies commonly used to reduce VOC emissions from a combustion turbine. For this reason review of BACT focused on identifying the lowest achievable emission limit.

All of the simple-cycle combustion turbines identified in the NOx BACT section (Escondido Energy Center, El Cajon Energy, Orange Grove Energy, CPV Sentinel, Panoche, and Walnut Creek) are permitted with a VOC emission rate of 2.0 ppmvd @ 15% O_2 averaged over one hour. No lower emission rates were found, even for combined-cycle plants, so the District concludes that 2.0 ppmvd VOC @ 15% O_2 is BACT for VOC. Initial and subsequent source testing will be used to determine compliance with these limits.

PM_{10}:

The Applicant initially proposed a limit of 3.5 lb PM_{10} per hour. However based on the District's review of previous source test results conducted during review of the Pio Pico Energy Center, a 3.5 lb/hr limit may not be achievable continuously for every hour. Specifically test results from other LMS 100 installations (Walnut Creek Energy Park, CPV Sentinel, Panoche Energy Center) found a maximum hourly PM emission level of 4.99 lb PM/hr with an average of 1.74 and standard deviation of 1.22 lb/hr[10]. Based on this information, the District believes that a short term emission rate of 5.0 lb/hr and a long term (annual) emission rate of 3.5 lb/hr for each turbine are appropriate. No lower emission rates were found in any determinations contained in the EPA clearinghouse. Therefore, these emission rates are determined to be BACT for this project.

As stated in Section 2.1.8 of the original application submittal, the project will utilize air-cooled fin-fan coolers, heat exchangers with closed loop circulating water pumps, and an evaporative cooler where 50% of evaporative cooling water is lost with the turbine exhaust, and the remainder recycled to the raw water storage tank. Since these emissions pass through the gas turbine exhaust stacks they are included in the turbine PM_{10} emission limit and, therefore, there is no need to address these emissions separately in a BACT determination.

SOx:

The Applicant proposed the use of natural gas fuel as BACT for SOx based on gas sulfur limits of 0.75 gr/100 scf and 0.25 gr/100 scf (both specified as total sulfur) for short term and long term averaging, respectively. These are equivalent to emission rates of 0.0021 and 0.0007 lb/MMBtu, respectively. The Applicant determined that there are no in-stack controls to be considered since the types of controls (scrubbers) used for plants with higher uncontrolled sulfur emissions would not achieve a cost effective level of control when employed with natural gas combustion. The District concurs with this assessment.

The District reviewed previous permits issued by it and other agencies to determine whether the sulfur limits proposed by the Applicant can be considered BACT. The FDOC for the CPV Sentinel plant

[10] Letter from Gary Rubenstein (Sierra Research) to US EPA Region 9 RE: PM BACT determination for PSD analysis for Pio Pico Energy Center, 8/15/13. Table 4.

included BACT emission rate of 0.06 lb/MMBtu which far exceeds the levels permitted for this plant (this level was based on the NSPS subpart KKKK emission rate, not actual gas sulfur content). The Pio Pico Energy Center and original Carlsbad Energy Center were evaluated using the limit of 0.75 gr S/100 scf gas.

Upon review of SDG&E tariffs, it was determined that SDG&E[11] Rule 30 limits sulfur content to no more than 0.75 gr total S/100scf. There is no separate limit for a long-term average. SDG&E provides monitoring data for their natural gas, listing < 0.75 gr/100 scf for the most recent quarterly average. Based on this information, the District concurs that the use of natural gas with the proposed sulfur contents is BACT. To ensure continuous compliance with this level, sulfur content of any gas is limited to no more than 0.75 gr/100scf with an annual average of 0.25 gr/100 scf, both as sulfur, by proposed permit conditions (the lower annual limit is based on the annual emissions used in the AQIA analysis). This will be determined using periodic fuel testing, and may be determined using testing conducted by the gas utility, provided that testing data is provided in such a way that compliance with the annual average limit of 0.25 gr/100 scf can be assessed (reports simply listing sulfur content as <0.75 gr/100 scf are insufficient).

Startup/Shutdown and Commissioning:

For startup and shutdown operations, BACT is typically considered to be a limitation on the mass emissions during each startup and shutdown period along with a limitation on the duration of each startup and shutdown.

Previous permits issued were reviewed to verify that the emission rates and startup and shutdown times proposed for this project are consistent with other BACT determinations. Specifically, other projects utilizing LMS 100 PA turbines were reviewed. The Pio Pico project was permitted (FDOC) with a startup time of 30 minutes/event and maximum emission rates of 22.5 lb NOx/event, 17.9 lb CO/event and 4.7 lb VOC/event. Shutdowns were limited to 11 minutes, at emission rates of 6.0 lb NOx/event, 47 lb CO/event and 3 lb VOC/event. The application for the CPV Sentinel plant FDOC issued by SCAQMD specified 25 minute startups and 10 minute shutdowns. This was determined to correspond to emissions of 24.9 lb NOx/event, 15.89 lb CO/event and 4.3 lb/hr VOC for a startup hour. Shutdown emissions were calculated at 6 lb NOx/event, 35 lb CO/event and 3.0 lb VOC/event[12].

The Applicant provided manufacturer estimates for turbine startup and shutdown emissions and durations. LMS100 PA turbines are advertised as having some of the lowest startup times for large simple-cycle turbines. Maximum startup duration is estimated at 25 minutes with emission rates of 14.7 lb NOx/event, 7.4 lb CO/event and 2.0 lb VOC/event by the manufacturer. Maximum shutdown duration is estimated at 13 minutes, with emission rates of 0.6 lb NOx/event, 3.4 lb CO/event and 2.4 lb VOC/event. While shutdown time is slightly longer than that used for Pio Pico or CPV Sentinel, the emission rates over this time are lower for each pollutant.

[11] http://www.sdge.com/rates-regulations/current-and-effective-tariffs/gas-tariff-book-rules
[12] http://docketpublic.energy.ca.gov/PublicDocuments/Regulatory/Non%20Active%20AFC's/07-AFC-3%20Sentinel/2007/July/TN%2041768%2007-31-07%20Applicant's%20Permit%20to%20Construct-Permit%20to%20Operate%20Application.pdf

For NOx, in addition to the above limit, the proposed permit conditions require that ammonia is injected at all times the turbine is operating and catalyst temperature exceeds 540 °F to ensure the maximum control of NOx emissions feasible during startups and shutdowns. Based on the anticipated manufacturer's information provided by the applicant, the minimum temperature that ammonia can be injected to control NOx without excessive ammonia slip is 540 degrees °F. The proposed permit conditions require continuous monitoring of the catalyst temperature for compliance with this limit and to prevent damage to the catalyst at high temperatures (high limit 870 °F continuously, 932 °F intermittently).

Based on the above information, the District has determined that BACT is satisfied by limiting startup duration to no more than 25 minutes and shutdown duration to no more than 13 minutes per event; with NOx, CO, and VOC emissions limited to the manufacturer estimates above; and, for NOx, with ammonia flowing to the SCR when the catalyst's minimum feasible temperature for NOx control is reached. NOx and CO emissions are required to be monitored by the CEMS on a minute-by-minute basis to determine compliance with the lb/event emission limits. VOC emissions rates during startups and shutdowns are determined using CO as a surrogate. All startup and shutdown emissions must also be accounted for in determining compliance with applicable annual emission limits. Additionally, the number of startups allowed for each turbine is limited to 400 per year by the proposed permit conditions.

For commissioning, the Applicant provided manufacturer information detailing the various operational modes during commissioning with an estimate that up to 213 hours of operation will be required for initial commissioning where emissions are expected to exceed BACT emission levels for normal operations and startups and shutdowns. This number of hours is reasonable for commissioning purposes, so BACT for commissioning is considered a limit of the number of commissioning hours and including emissions from the turbines during the commissioning year in determining compliance with the annual emission limits.

<u>Other BACT Considerations and Emission Limits:</u>

The District NSR rules do not explicitly regulate $PM_{2.5}$. For all equipment covered by this BACT determination, all PM_{10} is considered to be $PM_{2.5}$, so the determination for PM_{10} would also be valid for emissions of $PM_{2.5}$.

The Applicant has proposed a CO emission limit of 4 ppmvd at 15% O_2 averaged over each hour to limit emissions of CO to less than 100 ton/yr. Proposed permit conditions require compliance with a 4 ppmvd CO at 15% O2 one hour average limit.

The District also reviewed the analysis submitted by the Applicant analyzing the feasibility of lower emitting power generation technologies and installation of combined-cycle gas turbines instead of simple-cycle. This analysis is relevant to reviewing BACT for all pollutants since they could potentially result in lower emissions on a lb/MWh basis of all pollutants for which BACT is triggered. The analysis looked at feasibility for renewable energy technology (wind/solar), alternative generating technologies (combined-cycle), alternative fuels, energy efficiency and, for GHGs, carbon capture/storage. Renewable technologies were eliminated as an infeasible option due to space limitations and the site not being suited for renewable generation. The analysis eliminates combined-cycle turbines primarily because the turbines

may need to undergo multiple startups per day which would decrease the lifespan of the turbines and, therefore, combined-cycle plants would not meet the requirements. Additionally, the turbine heat rate (the amount of fuel energy required to generate a given amount of electrical energy) would only be marginally improved (and potentially lower) if the turbines were subject to frequent enough start and stop cycles. Alternative fuels were eliminated because there are no available lower emitting fuels for turbines. To address energy efficiency, the Applicant stated that these LMS 100 turbines have the lowest heat rates available on the market for simple-cycle turbines, and verified this by providing heat rates of different turbines, showing the LMS 100 turbines as the most efficient[13]. The heat rate listed in this table (7,947 btu/kW-hr on a LHV basis) is comparable to the heat rates achieved with similar LMS 100 turbines for CPV Sentinel(7,686-7,998 at full load depending on ambient conditions)[12]. Internal combustion engines were identified as potentially having more favorable heat rates than simple-cycle gas turbines, however the District agrees that since heat rate would only improve marginally; NOx emissions would increase substantially; and the LMS 100 meets the project objectives for this project, internal combustion engines can be eliminated from the analysis for this particular project.

The Applicant also considered whether the installation of combined-cycle turbines would be technologically feasible and still meet all of the stated project objectives (provide grid voltage support near the plant, supply some of the power previously generated by SONGS and provide peaking reserves for support of future renewable energy projects). The District agrees with the determination presented by the Applicant that combined-cycle plants similar to those proposed for the licensed CECP are not technologically feasible if the plant is required to meet the worst-case expectations for load following and required ramp rates in the early evening when solar generation begins to drop off as demand increases. However it is unclear whether technology used by the independent system operator and utilities to predict required operating loads and respond to load swings will advance before construction of the plant as these entities gain experience integrating renewables into the grid, such that the worst-case design scenarios for necessary ramp rates and startup and shutdowns will not occur. If fewer startups and shutdowns are necessary and the utilities are able to reasonably predict how much power will be needed with sufficient lead time to bring a combined-cycle unit to the necessary load, then there is a point where the maintenance issues with frequent startups and shutdowns would be eliminated, and operation of a combined-cycle unit would have lower emissions on a lb/MW-hr basis than a comparable simple-cycle unit.

The previous sections of this BACT analysis have established that the proposed simple-cycle turbines meet BACT requirements for simple-cycle turbines, and based on the alternative technologies analysis provided by the Applicant, The District preliminarily agrees that simple-cycle turbines are a reasonable choice to meet all of the stated project objectives and that the alternatives discussed are not technologically feasible.

Rule 20.3(d)(2): AQIA

This section requires that the District conduct an air quality impact analysis (AQIA) for all projects resulting in increases of emissions above thresholds listed in Table 20.3-1 of the rule to assess the impacts

[13] http://docketpublic.energy.ca.gov/PublicDocuments/07-AFC-06C/TN203013_20140829T135233_Sierra_Research_Response_to_Air_District_Re_Gas_Turbine_Heat_Ra.pdf

of the proposed equipment on compliance with applicable ambient air quality standards. Each project must be shown not to cause new violations or additional violations of either the State or National Ambient Air Quality Standards or prevent or interfere with the attainment or maintenance of those standards. While emission reductions from the existing EPS units would mitigate the emission impacts to some extent, the Applicant prepared an AQIA assessing the impacts for emissions of PM_{10}, $PM_{2.5}$, NO_2, SO_2 and CO that did not include the associated reductions from shutdown of the EPS units. Pursuant 20.3 (d)(2)(iv) no AQIA is required for NOx or VOC impacts on ozone.

Modeling was performed based on the worst-case hourly and annual emission rates during normal operation, startup and shutdown, and commissioning. The analysis includes all six proposed gas turbines and the emergency and fire pump engines for normal operation and startup and shutdown. For commissioning the analysis was based on all six proposed turbines being commissioned simultaneously. The emergency and fire pump engines are assumed not to be operating during commissioning, which is ensured through proposed permit conditions. The applicant also modeled the simultaneous operations with emissions from the existing EPS units during commissioning.

For each ambient standard, the Applicant initially used a screening assessment to identify which modes resulted in the highest impacts[14]. These scenarios were then modeled in detail using a refined model. The concentrations determined from this analysis were added to the background levels based on available monitoring data to determine the maximum impacts. Applicable ambient standards and background concentrations can be seen in Table 4-1 of the AQIA report in Appendix C and included standards for NO_2, SO_2, CO, PM_{10} and $PM_{2.5}$.

The District reviewed the analysis conducted by the Applicant and made some changes before remodeling to determine compliance with each standard. Particulate emissions were adjusted upwards for short-term (24-hour averaging period) rates to use 5 lb/hr instead of 3.5 lb/hr. The District included the emissions from the two diesel engines when modeling startup and shutdown scenarios. Emissions from the Diesel engines were updated to reflect calculations seen in Table 6 of the Section 5. For commissioning, the District modeled two separate scenarios for full load and idle (no load) with estimated idle emissions instead of an average of the two conditions for the idle mode. It was assume that there was no emission control, including water injection, in either commissioning mode examined. For all District assessments, revised background concentrations were used to reflect the most accurate available data. The full AQIA report is contained in Appendix C.

Based on these results, the proposed project is not expected to contribute to any violations or cause any additional violations of any applicable standard, which satisfies the requirements of this Section 20.3(d)(2). Proposed permit conditions contain limits on mass emissions of each applicable pollutant during each operating mode and also specify exhaust stack configurations to reflect the parameters used in the analysis to ensure the operation of the proposed equipment reflects that used in the analysis. Appendix C contains the AQIA report with details of the analysis. Tables 4-2, 4-3, 4-4 and 4-5 of the of AQIA report contain the numerical results of the AQIA.

[14] See Table 5.1E-3 of the application submittal.

It should be noted that, following standard District AQIA modeling practices, the results for $PM_{2.5}$ and PM_{10} impacts do not include any potential impacts from secondary $PM_{2.5}$ formation resulting from chemical reactions in the atmosphere after pollutants are discharged from the stack. On May 20th, 2014, EPA issued guidance requiring addressing impacts of secondary $PM_{2.5}$ for sources seeking PSD permits. While not required by the EPA guidance since it is unlikely that this project triggers federal PSD requirements, a preliminary analysis, which the District believes provides conservatively high results, for impacts of secondary $PM_{2.5}$ (and by extension PM_{10}) formation conducted by the District indicates that the conclusions of the AQIA would not change if secondary pollutant formation were to be included in the modeling.

Rule 20.3(d)(3) and (4): PSD

As previously discussed, this site is an existing PSD source, but the project does not result in a contemporaneous emission increase in excess of the PSD modification thresholds for any pollutant, so no further PSD requirements apply. This is ensured by proposed conditions limiting the actual emissions from the existing EPS units in sufficient amounts such that at no time will the contemporaneous emission increase exceed the PSD modification thresholds. Table A-13 in the appendix shows the quantities of reductions required based on the number of the proposed new units that have started up. After completion of the project, the potential to emit for all pollutants would be reduced sufficiently such that the site would no longer be a PSD stationary source.

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

An AQIA was prepared for this project under Section 20.3(d)(2) of this rule and, therefore, a public notice and comment period is required. Requirements include publishing a notice of the proposed action in at least one newspaper of general circulation, providing the EPA and CARB with notice of the proposed action and relevant information regarding the decision including analyses and documentation to support the proposed action, the District's evaluation of the project and any draft permits, and providing a 30-day comment period for the public, EPA, and ARB to provide comments for consideration by the District. The notice will be published in the San Diego Daily Transcript and San Diego Union Tribune and mailed to the EPA, ARB, and neighboring air districts and will specify the dates for the 30-day comment period.

Rule 20.3(d)(5)-(8): Emission Offsets

Emission offsets are required for any project that results in a major modification at an existing major source or results in a new major stationary source by itself for federal nonattainment air pollutants or their precursors. The District is currently only in nonattainment of the federal 8-hour ozone standard. As ozone precursors, NOx and VOCs are the only nonattainment pollutants in the District. The EPS is currently an existing major source. The proposed permit conditions contain annual emission limits for NOx and VOC emissions to ensure that the contemporaneous increase for NOx or VOC emissions is less than 24.9 ton/yr, which is below the major modification threshold of 25 ton/yr.

Rule 20.3(e)(1): Compliance Certification

This project is not subject to either LAER or offset requirements, and, therefore, a compliance certification is not required.

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

This project is not subject to either LAER or offset requirements, and, therefore, an alternative siting and alternatives analysis is not required.

Rule 20.5 – Power Plants

This section requires that the District issue a preliminary determination of compliance (PDOC) as part of the application for certification process once it has determined that the proposed power plant will comply with all applicable District regulations. After a comment period has been provided and the District has considered any comments submitted, the District will issue a final determination of compliance (FDOC) which will confer the same rights and privileges as an authority to construct after the project license application is approved by the CEC.

6.2 District Prohibitory Rules

Rule 50: Visible Emissions

This rule limits the opacity of air emissions to a shade no darker than that designated Number 1 on the Ringlemann Chart, or an equivalent opacity (20%). This requirement is specified in proposed permit conditions and the use of natural gas as fuel is expected to ensure compliance with this requirement.

Rule 51: Nuisance

The rule prohibits the discharge of air contaminants in such quantities which cause injury, detriment, nuisance or annoyance to a considerable number of persons or the public; which endanger the comfort, repose, health or safety of any such persons of the public; or which have a natural tendency to cause injury or damage to business or property. Proposed permit conditions specify this requirement and the use of natural gas as fuel is expected to ensure that no public nuisance results from this equipment.

Rule 53: Specific Air Contaminants (Particulate and SO_2)

This rule limits emissions of sulfur compounds from any source to no more than 0.05% by volume on a dry basis (500 ppmvd) and limits combustion particulate emissions to no more than 0.10 grains/dry standard cubic foot corrected to 12% CO_2. Since sulfur emissions are based only on gas flow rate, the concentration can be estimated assuming the sulfur contents, heat contents and F-factors described in the Section 5:

$$Sulfur\ Content\ (fractional)$$
$$= \left(\frac{0.75\ gr\ S}{100\ scf\ gas}\right)\left(\frac{1\ scf\ gas}{1010 \times 10^{-6} MMBtu}\right)\left(\frac{1\ MMBtu\ gas}{8710\ dscf\ exhaust}\right)\left(\frac{1\ lb}{7000\ gr}\right)\left(\frac{64\ lb\ SO2}{32\ lb\ S}\right)\left(\frac{1\ lb-mol\ SO_2}{64\ lb\ SO_2}\right)\left(\frac{385\ scf}{lb-mol}\right)$$
$$= 1.47\ ppmvd\ at\ 0\%\ O_2 < 500\ ppm$$

Particulate emission concentration can also be estimated. Since particulate emissions are assumed to be 5 lb/hr regardless of fuel flow rate, the highest particulate concentration will occur during a startup or shutdown. Based on data provided by the manufacturer through the applicant and as shown in Table 4, a

shutdown has the lowest heat input. Assuming emissions are proportional to the duration of the shutdown (5 lbs/hr x 13mins/60mins = 1.08 lb) and using the CO_2 F-factor (F_c) of 1040 dscf CO_2/MMBtu gas:

$$PM\ Emissions\ \left(\frac{gr}{scf}\right)$$
$$= \left(\frac{1.08\ lb\ PM}{shutdown}\right)\left(\frac{shutdown}{48.63\ MMBtu}\right)\left(\frac{1\ MMBtu\ gas}{1040\ dscf\ CO_2}\right)\left(\frac{12\ dscf\ CO_2}{100\ dscf\ exhaust\ at\ 12\%\ CO_2}\right)\left(\frac{7000\ gr}{lb}\right)$$
$$= 0.018\frac{gr}{dscf}(corrected\ to\ 12\%\ CO_2, dry) < 0.1\ gr/dscf$$

Therefore, the emissions from the gas turbines are expected to comply with this standard. The turbines must also comply with this limit during commissioning. The lowest fuel input is during idle operations, and based on an emission rate of 5 lb/hr and 128.7 MMBtu/hr, the concentration would be 0.03 gr/dscf corrected to12% CO_2, which also complies with the limit.

Emissions from the diesel engines are also subject to the sulfur emission limit (the particulate emission requirements do not apply per 53(b)(1)). The use of CARB diesel fuel ensures that sulfur emissions do not exceed this amount, which can be calculated the same way as for gas fuel except it is based on the CARB standard of 15 ppmw sulfur in the fuel and heat content of 137,000 btu/gal and F-factor (F_d) of 9190 scf/MMBtu:

$$Sulfur\ Content\ (fractional)$$
$$= \left(\frac{15\ lb\ S}{10^6 lb\ Diesel}\right)\left(\frac{1\ lb\ diesel}{0.01943\ MMBtu}\right)\left(\frac{1\ MMBtu\ gas}{9190\ dscf\ exhaust}\right)\left(\frac{64\ lb\ SO_2}{32\ lb\ S}\right)\left(\frac{1\ lb-mol\ SO_2}{64\ lb\ SO_2}\right)\left(\frac{385\ scf}{lb-mol}\right)$$
$$= 1.0\ ppmvd\ (at\ 0\%\ O_2)\ < 500\ ppm$$

Therefore, emissions from the diesel engine also comply with this requirement. None of the other emission sources produce particulate matter or SO_2 emissions, and, therefore, are not subject to this rule.

Rule 62: Sulfur content of fuels

This rule limits gaseous fuel to containing no more than 10 grains of sulfur compounds (calculated as hydrogen sulfide) per 100 cubic foot of dry gaseous fuel, and limits sulfur fuel to containing no more than 0.5 percent sulfur by weight. Proposed permit conditions require the use of natural gas fuel containing less than 0.75 gr S/100 scf for the gas turbines and diesel fuel containing no more than 15 ppmw sulfur, which ensures compliance with this rule.

Rule 68: Oxides of Nitrogen from Fuel Burning Equipment

This rule applies to any fuel burning equipment with a maximum heat input rating of 50 MMBtu/hr or more, so it would apply only to the gas turbines. However, Rule 69.3, which is applicable to the combustion turbines, and Rule 69.4, which is applicable to the diesel engines, state that any emission unit subject to the rule is exempt from Rule 68. This means Rule 68 does not apply to either the gas turbines or diesel engines.

Rule 69.3: Stationary Gas Turbines Reasonably Available Control Technology (RACT)

This rule applies to the gas turbines and implements federal RACT for those emission units and approved into the State Implementation Plan (SIP) for San Diego County. Emission standards of this rule apply at all times except for up to 120 continuous minutes during any startup or shutdown period. This rule limits emissions to no more than 42 ppmvd corrected to 15% oxygen when operating on gaseous fuel. The rule furthermore requires the installation of continuous monitors to show compliance with the emission limit and for the facility to keep records of startup and shutdowns. Annual source testing is also required. Because this is a RACT rule this emission limit are specified separately in the proposed permit conditions. The proposed permit conditions require that the monitoring requirements are required to be met with a certified CEMS, contain a requirement to record startup and shutdown durations, and require annual source testing for NOx.

Rule 69.3.1: Stationary Gas Turbines Best Available Retrofit Control Technology (BARCT)

This rule also applies to gas turbines and implements state BARCT requirements. This rule limits NOx emissions from gas turbines based on the thermal efficiency of the turbine. For units with a power rating greater than 10 MW, the standards when operating on gaseous fuel are (in ppmvd corrected to 15% O_2): 15 x E/25 when no post combustion controls are installed and 9 x E/25 when post combustion (SCR/oxidation catalyst) controls are installed, where E is the thermal efficiency based on the fuel's LHV. The "no-controls" limit will apply only during commissioning, after which point the lower "with controls" limit shall apply. The thermal efficiency E is calculated as:

$$E = \frac{(MRTE)x\ (LHV)}{(HHV)} = \frac{(41.85\%)x\ (1)}{(1.11)} = 37.7\%$$

Where
LHV/HHV = 1/1.11;
MRTE[15] = Manufacturer's rated thermal efficiency at peak load, after correction to LHV

The NOx emission limits are, therefore, 15 x 37.7/25 which equals 22.6 ppmvd corrected to 15% O_2 with no controls and 9 x 37.7/25 which equals 13.6 ppmvd corrected to 15% O_2 with controls. These limits apply at all times except for 120 consecutive minutes during startups and shutdowns. To show compliance with this limit, the proposed permit conditions require installation of a CEMS and parameter monitoring system that will record NOx emissions, fuel flow and other exhaust data. Times and durations of startups and shutdowns will also be monitored and recorded. NOx concentrations are averaged over each hour. Annual source testing consisting of three subtests is required.

Rule 69.4: Stationary Reciprocating Internal Combustion Engines (RACT)

This rule applies to stationary internal combustion engines located at major stationary sources of NOx and implements federal RACT and is approved into the SIP. This source is a major stationary source of NOx,

[15] Based on GE performance run for average temperature of 60.1 °F, 100% load, no evaporative inlet cooling, heat input is 887 MMBtu/hr LHV to result in generation of 108.8 MW which, using 3412.1 btu/hr = 1 kW, is an efficiency of 41.85%. The max efficiency of 44% stated in the application does not appear to include inlet and exhaust pressure losses, so the performance runs conducted by the manufacturer were used to establish the efficiency of 41.85%.

so the emergency and fire pump diesel engines are subject to this rule. The emission standards of this rule do not apply to emergency engines provided they are operated for fewer than 52 hours for nonemergency purposes during every calendar year. These engines are limited to no more than 50 hours for nonemergency use during each calendar year. Additionally, the rule requires that the owner or operator keep maintenance records and an operating log with dates, times and reason (i.e. emergency operation, testing, etc.) for operation. The engines must also be equipped with non-resettable fuel or hour meters. The proposed permit conditions specify all of these requirements, and, therefore, compliance is expected.

Rule 69.4.1: Stationary Reciprocating Internal Combustion Engines (BARCT)

This rule is almost identical to Rule 69.4 except that it applies regardless of the major source status of the facility. Additionally, the rule requires that emergency diesel engines meet emission limits of 535 ppmvd NOx and 4500 ppmvd CO, both corrected to 15% O_2. The NOx limit is defined in the rule as equivalent to 6.9 g/bhp-hr, and both engines are certified with NOx emissions below this level[16]. CO emissions from the diesel engines are also below 4500 ppmvd based on the manufacturer's emission estimates. The rule also requires that only California diesel fuel be used. Finally, the rule requires annual maintenance and the same record-keeping of hours of operation and maintenance conducted as required by Rule 69.4. Because these are both EPA certified engines, they are exempt from source testing per Section 69.4.1(i)(4). Therefore, compliance with this rule is assured through proposed permit conditions requiring CARB diesel fuel, installation of hour meters, limit on nonemergency operation of no more than 50 hours/calendar year, annual maintenance and records including maintenance manual, maintenance log and operational log. Additionally, permit conditions require that the engine be operated only for emergency purposes and for maintenance and testing purposes.

Rule 1200: Toxic Air Contaminants

Rule 1200 regulates the emissions of toxic air contaminants in San Diego County by placing limits on allowable health risk and health effects on surrounding residences and businesses due to increases in emissions of these air contaminants. This is accomplished through a health risk assessment (HRA) that models dispersion of air contaminants based on emission rates, exhaust properties, atmospheric data and geography. The Applicant performed an HRA and submitted it to the District for review. The HRA considered emissions from the gas turbine engines and the two diesel engines. In addition to these emissions, the District estimated added emissions from the turbines due to trace residual heavy metals contained in the turbine injection water. The district also performed a separate analysis for low-load operation during commissioning to assess acute HHI during those portions of commissioning.

Rule 1200 limits the increase in health hazard index (HHI) to no more than 1.0 for both chronic and acute health effects. HHI is a ratio of potential exposure to the exposure required to produce health effects in more sensitive individuals, so a value less than 1.0 indicates no potential for adverse health effects. Cancer risk increase is limited to an increase of no more than one in one million, unless the equipment is equipped with toxics best available control technology (T-BACT) in which case the standard is no more than an increase of ten in one million.

[16] See attachment 7 included with the 6/27/2014 incomplete letter response

Based on the District review of the Applicants HRA, as modified by including metal emissions from the turbine injection water, the estimated potential cancer risk for the maximum exposed individual is an increase of 0.45 in one million, which is below the acceptable cancer risk standard. The maximum increase in incremental cancer risk for the maximum exposed resident is 0.065 in one million, which is also below the standard. It should be noted that the majority of the potential cancer risk is a result of the diesel engine emissions. The chronic and acute HHIs were both below 1.0 for each emission scenario analyzed, including startup/shutdown and commissioning operations and considering inversion breakup and shoreline fumigation. This demonstrates that the proposed project is in compliance with Rule 1200. Emission calculations and the District's detailed HRA report can be found in the appendices. Assumptions and methods used in calculations can be seen in the Section 5, Appendix A and the detailed HRA report (Appendix B).

In addition to the metal emissions from water injection and commissioning cases previously mentioned, the District noted a few additional changes to the data used by the Applicant, but these would not have a net effect of increasing the predicted toxic impacts. The Applicant calculated emissions of the diesel engine based on 50% load for maintenance and testing, using the full-load emission PM emission factor, but assuming 200 hours per year of operation for engine. Standard District procedure is to assume full load for maintenance and testing operations, but using the weighted emission factor used by the EPA for certification purposes, and based on the limit of 50 hours per year for operation for each engine. The net difference is that the procedure used by the Applicant is more conservative, so additional HRA analysis is not necessary.

Additionally, the Applicant assumed natural gas with a higher heating value of 1020 btu/scf, but the District expects the worst case heat content could be closer to 1010 btu/scf, which would result in an almost negligible increase in emissions. The Applicant also assumed 800 startup/shutdown hours per year per turbine (each hour consisting of a startup and a shutdown followed by another startup), but proposed permit conditions limit to a maximum of 400 startups per year per turbine. Finally, when calculating emissions, the Applicant used a ratio of 2.48 for the ratio of startup/shutdown toxic emissions to steady state toxic emissions based on the VOC emission ratio, but the worst case VOC ratio is for an hour with a shutdown, startup, 9 minutes steady state operation and a second shutdown which had a ratio of 2.84. Additionally the ratio used in the Applicant's HRA for calculating emissions during commissioning was 2.0, when the highest ratio based on VOC emissions is 3.13 during sync idle. As previously discussed this was accounted for in a separate acute analysis and was not accounted for in the full HRA. However, the combination of under prediction of emissions by the Applicant using the higher heat content and lower VOC ratios was more than offset by the use of 800 startup/shutdown hours instead of the maximum of 400 allowed by the proposed permit conditions. No additional analysis is, therefore, required.

A final consideration is that Rule 1200 is based on increases of emissions due to a project. Since as proposed by the Applicant project will also include a reduction in emissions from the existing EPS units, there is a likely substantial reduction in chronic HHI and cancer risk that is not accounted for in this analysis, which would only serve to make results more favorable. Based on all the above considerations, the requirements of Rule 1200 are satisfied and the proposed equipment can be considered in compliance with this rule.

Regulation XIV: Title V Federal Operating Permits

The facility is a major source for the purposes of Title V and currently operates under permit number APCD2005-TIV-974488. The Applicant will be required to submit an application for a Title V Permit modification for the project. District rule 1414(c) requires that the initial application for new and modified sources be submitted not later than 12 months after the source has commenced operation.

6.3 State Regulations Implemented by the District

CA Health and Safety Code Section 42301.6: School Notification

This law requires that the District prepare a public notice for all proposed projects located within 1000 ft of a school that will result in the emission of toxic air contaminants. There are no schools located within this distance of the proposed project, so this project is not subject to this public notification requirement.

Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines (Title 17 California Code of Regulations Section 93115)

Both the emergency and fire pump engines are subject to this rule which applies to any new, stationary compression ignition engines with a power rating greater than 50 bhp. Both engines are considered emergency engines for the purpose of this rule since the operation will be restricted to unlimited use in emergency situations, allow no more than 50 hr/yr for maintenance and testing purposes, and allow no use for other purposes. Applicable requirements of this regulation are as follows:

Section 93115.5 requires that the engines be fueled with CARB diesel or other listed fuel.

Sections 93115.6(a)(1) and (2) require that engines not be operated for more than 30 minutes prior to a rotating electrical outage upon notification from the electrical utility that an outage is scheduled. The section also limits operation of engines located near schools. These engines are not located near a school so these provisions do not apply, and proposed permit conditions specify the restriction on operating more than 30-minutes prior to an impending rotating outage.

Section 93115.6(a)(3) Requires that emergency engines not be operated for more than 50 hr/yr for maintenance and testing, and that the engine must be EPA certified and meet the following emission limits based on engine power:

Max. Engine Power	Model year	PM (g/bhp-hr)	NMHC+NOx (g/bhp-hr)	CO (g/bhp-hr)
HP > 750	2008+	0.15	4.8	2.6

Based on information provided with the application, the emergency engine has a power rating of 779 bhp, and is certified by the EPA under engine family ECPXL15.2HZA with emission rates of 0.052, 2.24, 0.075 and 0.67 g/bhp-hr for PM, NOx, HC and CO respectively as listed in the EPA emission data[16]. Proposed permit conditions require that an EPA certified engine be installed which ensures the engine meets these certification requirements and proposed permit conditions allow up to 50 hr/yr of operation for maintenance and testing.

Section 93115.6(a)(4) Requires that fire pump engines not be operated for more than the number of hours required by NFPA 25 for maintenance and testing, and that the engine be certified and meet emission standards based on engine power and model year:

Max. Engine Power	Model year	PM (g/bhp-hr)	NMHC+NOx (g/bhp-hr)	CO (g/bhp-hr)
300 ≤ HP < 600	2009+	0.15	3.0	2.6

Based on information provided with the application, the proposed fire pump engine has a nameplate maximum power rating of 327 bhp and is certified by the EPA under engine family EJDXL09.0114 with emission rates[16] of 0.11, 2.6, 0.1 and 0.7 g/bhp-hr for PM, NOx, HC and CO respectively as listed by the manufacturer. Proposed permit conditions require that an EPA certified engine be installed which ensures the engine meets these certification requirements. Proposed permit conditions allow up to 35 hr/yr of operation for maintenance and testing, which is sufficient to meet typical NFPA 25 requirements and additional hours are allowed if required by NFPA standards.

Section 93115.10(a) specifies information that must be supplied to the District prior to installation of the engines. All required information was included with the applications with the exception of engine serial number which need not be determined until the engines are installed.

Section 93115.10(b) requires the submission of emission data to show compliance with the applicable emission limits. This data was submitted so this requirement is met.

Section 93115.10(e) requires installation of non-resettable hour meters and, for those with diesel particulate filters, backpressure monitors that notify the engine operator as the backpressure limit for the engine is approached. These engines are not equipped with DPFs and proposed permit conditions require that each engine be equipped with a non-resettable hour meter.

Section 93115.10(f) requires that the owner/operator of each emergency standby diesel-fueled engine keep records of the use of the engine including hours of operation and the reason for each period of operation. Records must also be kept to demonstrate that all diesel fuel used is CARB diesel. The records are required to be kept for a total of 36 months with 24 months onsite (the proposed permit conditions require 5 years onsite for all records). All of these requirements are specified in the proposed permit conditions.

6.4 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

NESHAP Subparts YYYY and ZZZZ apply to gas turbines and reciprocating engines respectively, so each type of equipment are discussed under the relevant section below.

40 CFR Part 63 Subpart YYYY – Stationary Combustion Turbines

This rule applies to combustion turbines installed at major sources of hazardous air pollutants (HAPs). A major source of HAPs has PTE of greater than 10 tons per year of a single HAP or 25 tons per year of any

combination of HAPs. For the evaluation of the licensed CECP, the District determined that this site was a major HAP source with over 10 ton/yr hexane PTE for the boilers. After completion of the project including removal of the existing EPS units, this site will no longer have a PTE in excess of 10 ton/yr of any single HAP or 25 ton/yr of combined HAP (see Table A-8, ammonia is not classified as a HAP by the US EPA), so will no longer be a major source. However until the boilers are removed, the site is a major source of HAP.

However, the EPA has stayed the emission standards in this rule for gas-fired diffusion-flame turbines, so the proposed turbines would only have to comply with initial notification requirements[17]. Because these turbines are expected to startup at a time that this facility is a major source of HAP, proposed permit conditions require that the initial notification requirement of 40 CFR 63.6145(c) be complied with. This requires that within 120 days after becoming subject to this subpart, a notification be submitted to the EPA with the information specified in 40 CFR 63.6145(d). No further requirements apply under this section.

40 CFR Part 63 Subpart ZZZZ – Reciprocating Internal Combustion Engines (RICE)

This rule applies to the emergency and fire pump diesel engines. It applies to all reciprocating internal combustion engines (RICE) located at both major and area sources. This rule is delegated to the District for implementation by the EPA. As discussed, this site is expected to be considered a major source when these engines become operational. This rule has the following limited exemptions:

Section 63.6590(b)(1) lists stationary RICE that only require initial notifications, including new emergency stationary RICE with a site rating of more than 500 bhp located at major sources. 40 CFR 63.6590(c) lists RICE that comply with NESHAP Subpart ZZZZ by complying with the corresponding NSPS, 40 CFR 60 Subpart IIII for compression ignition engines, including new RICE located at area sources and new emergency RICE with a site rating of less than or equal to 500 bhp. This means that only the emergency engine is subject to requirements under this rule and only an initial notification would be required. The fire pump engine is only subject to NSPS subpart IIII.

Since NESHAP subpart ZZZZ is delegated to the District, the applications for the engines can be considered the initial notifications, except that the applications do not have the required statement indicating that the source is a major source. Therefore, proposed permit conditions specify the requirement to notify the District that the source is a major source within 120 days of becoming subject to this subpart (starting up the emergency engine).

6.5 New Source Performance Standards (NSPS)

The gas turbines are subject to NSPS Subpart KKKK and the diesel engines are subject to Subpart IIII. Additionally, the EPA has proposed subpart TTTT which would regulate GHG emissions from stationary combustion turbines.

40 CFR Part 60 Subpart KKKK – Stationary Combustion Turbines

[17] 69 FR 51184. http://www.epa.gov/ttn/atw/turbine/fr18au04.pdf.

This subpart applies to all stationary combustion turbines with heat input in excess of 10 MMBtu/hr based on HHV.

Section 60.4320 requires that the turbines meet an emission limit for NOx contained in Table 1 of the subpart. Inspection of this table shows that the applicable standard for these >850 MMBtu/hr, electrical generating, gas turbines is 15 ppmvd at 15% O_2 (or alternatively 0.43 lb/MW-hr) when the turbine is operating in excess of 75% load. When operating at less than 75% load, the emission limitation is 96 ppmvd NOx at 15% O_2 (or 4.7 lb/MW-hr). These limits apply at all times, including startups and shutdowns. When the turbine is operated above 75% load (except very small durations at the end of startup and beginning of shutdown), the 2.5 ppmvd NOx BACT limitation applies and is more stringent, so the turbine is expected to comply with this limit. The 96 ppmvd NOx limit applies during startups and shutdowns and any times the turbines are operating below 75 percent load during normal operation. During normal operation, the BACT limit is more stringent. During startups and shutdowns, the average emission rate for NOx was calculated by rearranging equation 1 in the Section 5.1 to solve for the exhaust concentration. This calculation was performed for each startup and shutdown scenario and the results are presented in the table below. These values are substantially below the 96 ppmvd NOx limit (and actually are below the 15 ppmvd NOx limit), so compliance is expected. See emission Section 5.3 for description of each mode shown in the table and assumptions used in the calculations. The exact methodology used in the subpart to show compliance with these emission standards is explained below.

Table 14:Estimated Gas Turbine NOx Emission Rates During Non-steady State Operation

Operating Mode	Duration (mins)	Fuel (MMBtu - HHV)	NOx (lb)	NOx (ppmvd, 15% O_2)
Startup	25	293.57	14.7	13.6
Shutdown	13	48.63	0.6	3.35
Startup + Shutdown + Max SS	60	703	18.6	7.19
Startup + Shutdown + Startup	60	600.54	28.2	12.75
Shutdown + Startup + Max SS + Shutdown	60	538.43	17.3	8.70

Section 60.4330 requires that the turbines meet an emission limit for SO_2. The limits for these turbines are either (1) no emissions in excess of 0.90 lb SOx/MW-hr or (2) all fuel used must contain total potential sulfur emissions less than 0.060 lb SO_2/MMBtu. A natural gas sulfur content of 0.75 gr S/100 scf gas corresponds to an emission rate of 0.00213 lb/MMBtu, which is much lower than the standard, so the turbines are expected to comply with this requirement.

Section 60.4333 has general requirements for complying with the subpart. The only applicable requirement is to operate and maintain each turbine and control device in a manner consistent with good air pollution control practice. This is included in proposed permit conditions. Compliance with all proposed permit conditions ensures compliance with this general requirement.

Section 60.4335 explains how to demonstrate compliance with the NOx emission limits if the turbine uses water or steam injection, which this turbine does. The rule allows either the use of a parameter monitoring

system monitoring fuel flow and water injection rate, or allows the use of a CEMS monitoring NOx and diluent gas (O_2) to determine emissions in lb/MMBtu or ppmvd. The proposed permit conditions require the use of a CEMS to show continuous compliance.

Section 60.4345 contains requirements for the CEMS system. The CEMS may either be certified using either Performance Specification 2 of 40 CFR Part 60 (except 7-day drift test based on unit operating days instead of calendar days), or according to the procedures of appendix A of 40 CFR Part 75. RATAs must be performed on a lb/MMBtu basis. For each full unit operating hour, the NOx and diluent monitors must sample, analyze and record at least once each 15 minute quadrant for the hour to be valid. For partial hours, at least one valid point must be obtained for each quadrant of the hour the turbine operates. Only two valid points are needed for hours in which QA or maintenance activities are conducted to validate the hour. All monitors including fuel flowmeters, watt meters, temperature sensors, etc. must be installed, calibrated, maintained and operated according to manufacturer's instructions. The facility must maintain a QA plan for all continuous monitoring equipment described.

Section 60.4350 contains requirements for using CEMS data to identify excess emissions. This includes that all CEMS data be reduced to hourly averages and recorded in units of ppm (uncorrected) or lb/MMBtu for each valid unit operating hour of data. For missing data, the owner or operator is not required to report data substituted using the missing data procedures of part 75, and instead may report these periods as monitor downtime. All other monitored parameters must be reduced to hourly averages as well. For simple-cycle units, excess emissions are calculated on a 4-hour rolling average basis.

Sections 60.4360 and 60.4365 have requirements for monitoring sulfur content of fuel. Since only natural gas is combusted, sulfur content monitoring is not required per 60.4365(a) which specifies that, if a tariff sheet lists sulfur content below 20 gr S/100 scf gas, no monitoring is required. Since SDG&E provides this tariff sheet[18] indicating sulfur content below this level, no monitoring is required under this section provided fuel is supplied by SDG&E. However, other proposed permit conditions require monitoring of sulfur content.

Section 60.3475 requires the submission of reports of excess emissions and monitor downtime (including startups, shutdowns and malfunctions).

Section 60.4380 specifies that periods of excess emissions to be reported are any time where the 4-hour NOx emission rate exceeds the applicable standard. The 4-hour average includes the unit operating hour and three unit operating hours immediately preceding the subject unit operating hour. An emission rate is calculated if a valid NOx rate is obtained for three out of four hours. Periods of monitor downtime to be reported include any hours the turbine was operating but valid readings were not obtained. For periods where multiple emission limits would apply (i.e. the 4-hour averaging period includes periods of operating both above and below 75% load), the applicable standard is the average of the applicable standards during each hour. For each hour where multiple emission standards apply, the higher emission standard during that hour applies.

Section 60.4396 requires that reports be submitted by the 30th day following the end of each semi-annual reporting period. This is specified in proposed permit conditions.

[18] http://www.sdge.com/rates-regulations/tariff-information/miscellaneous-rate-related-information.

Sections 60.4400 and 60.4405 contain instructions for initial and periodic source testing. If testing is to be performed, EPA Method 7E or Method 20 may be used to measure NOx concentration along with EPA Methods 1 and 2 to determine stack gas flow rate or NOx and O_2 may be measured using Method 20 or Methods 7E and 3A, and then converted to lb/MMBtu using EPA method 19. Alternatively, if equipped with a CEMS, the initial performance test may be conducted as a RATA test. An additional requirement is that the test be conducted while the turbine is operating within +/- 25% of 100% peak load. This is specified in the proposed permit conditions.

40 CFR Part 60 Subpart IIII – Compression Ignition Reciprocating Internal Combustion Engines

Both diesel engines (fire pump and emergency) are subject to this regulation separately.

Sections 60.4201 through 60.4203 apply to engine manufacturers, so do not apply to this equipment. Section 60.4204 contains standards for nonemergency engines that do not apply to these engines since they are both emergency engines.

Section 60.4205 contains emission standards for each engine. The emergency engine is required to comply with the emission standards for nonroad compression ignition engines in 40 CFR 89.112 and 89.113. For engines in this power range and model year, these standards require the engine be certified to standards of 6.4, 3.5 and 0.20 g/kW-hr (4.8, 2.6, 0.15 g/bhp-hr) for NMHC+NOx, CO and PM respectively, which are often known as "Tier 2" standards. The engine is certified with emission levels below these values (see Section 6.3), so meets this requirement.

The fire pump engine is required to comply with the emission standards listed in Table 4 of Subpart IIII. The standards listed in this table are the same as listed for the fire pump engine under the California ATCM. As discussed, the proposed fire pump engine is certified and meets these requirements.

Section 60.4207 requires the use of low sulfur fuel. Proposed permit conditions require CARB diesel, which satisfies this requirement.

Section 60.4209 requires that emergency engines be equipped with a non-resettable hour meter and this is specified in proposed permit conditions.

Section 60.4211 requires that the engines be certified and both be operated and maintained according to the manufacturer's emission-related written instructions. Both engines are emergency engines under this rule, so are restricted to operating in certain scenarios. They may both be operated for unlimited duration in emergency situations, for maintenance and testing, emergency demand response and for other situations up to 50 hr/yr. However, proposed permit conditions to implement District Rule 69.4.1 and the California ATCM allow the emergency engine to operate in emergency situations and for up to 50 hr/yr maintenance and testing operations while the fire pump engine is limited to operation in emergency situations and for maintenance and testing operations up to the amount required by the NFPA.

Section 60.4214 requires that the owner or operator maintain logs of engine operation including durations and reason for use. This requirement is specified in proposed permit conditions. No notifications or reports are required.

The proposed permit conditions contain requirements to ensure compliance with the applicable portions of this subpart.

40 CFR Part 60 Subpart TTTT – Green House Gas Emissions for Electric Utility Generating Units

This regulation has currently been proposed by EPA, but not yet finalized. As proposed, the rule would only apply to facilities that were constructed to supply, and that do supply, 1/3 or more of potential electrical output to a utility distribution system. Since the proposed turbines are limited to 2700 hr/yr of operation (30.8%) by proposed permit conditions at the request of the Applicant, they cannot exceed the 33% threshold and, therefore, would not be subject to the requirements of this section as currently proposed.

6.6 Acid Rain

40CFR Part 72 Subpart A – Acid Rain Program

This subpart includes general provisions including definitions and applicability for the Acid Rain Program. This program is designed to reduce emissions of compounds that form acid including NOx and SOx. This is accomplished through a market based trading program where sources of pollution are assigned allowances based on their level of electricity production and emissions. These allowances may be transferred between parties, with each entity required to hold sufficient allowances to cover their emissions. Each gas turbine is subject to this program as a new "utility unit".

40CFR Part 72 Subpart C – Acid Rain Permit Applications

This subpart requires that the Applicant submit an Acid Rain application to the US EPA prior to the applicable deadline. Section 72.30(b)(2)(ii) requires the application be submitted 24 months prior to operation of each unit. Additionally, the units cannot be operated until an acid rain permit is issued by the EPA. The requirements are specified in the proposed permit conditions.

40CFR Part 73 – Sulfur Dioxide Allowance System

This part contains requirements for allocating allowances, tracking allowances, transferring allowances, auctions and direct sales, energy conservation and renewable energy reserve. The requirement to hold allowances is contained in proposed permit conditions.

40CFR Part 75 – Continuous Emission Monitoring (CEMS)

This part establishes the minimum requirements for using CEMs for demonstrating compliance with the Acid Rain Program provisions. Since these units combust only gas, they are only required to monitor NOx and CO_2 (or O_2) and have the choice of monitoring SOx or may use fuel flow monitoring and default sulfur emission factors to calculate emissions. Additionally subpart C of this part contains requirements for operating and maintaining the CEMS to ensure that accurate, valid data is collected. The CEMS is required to be initially certified and requires recertification if certain modifications are made. Required QA activities include linearity checks, 7-day calibration error tests, and relative accuracy test audits (RATA). Linearity and calibration error tests ensure that the monitors are measuring emissions accurately. RATA compare the CEMS readings to the results determined using a source test. The RATA

must be conducted annually except in certain situations where the turbine does not operate for more than 168 hours per calendar quarter. Finally, this part contains requirements for substituting data in a conservative manner for any hour when the CEMS does not record valid data, and these requirements are specified in the proposed permit conditions. Additionally the facility is required to operate according to an approved CEMS protocol, which will contain the above requirements and specific procedures in detail.

7.0 Additional Issues

None.

8.0 Conclusion and Recommendations

If operated in accordance with the proposed conditions specified in this Preliminary 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. (See appendix D for the proposed conditions)

Signed By Stan Moore / for Nick Hovres — 12-12-14
Project Engineer — Date

Signed By Stan Moore — 12-12-14
Senior Engineer — Date

Appendix A: Emission Calculation Tables

Table A-1: NOx Pre-Project Actual Emissions by Year, ton/yr

	2009	2010	2011	2012	2013
Unit 1	3.41	2.13	3.45	7.56	2.10
Unit 2	2.15	0.64	4.24	8.83	1.88
Unit 3	3.72	1.33	3.73	9.20	2.88
Unit 4	14.60	4.85	7.05	24.24	8.83
Unit 5	22.68	12.27	13.50	34.27	15.21
Peaker Turbine	0.39	0.86	0.32	2.62	2.21
Total	46.96	22.08	32.29	86.71	33.11
2-yr Rolling Avg.	NA	34.52	27.18	59.50	59.91

Table A-2: CO Pre-Project Actual Emissions by Year, ton/yr

	2009	2010	2011	2012	2013
Unit 1	24.18	32.42	46.80	20.00	21.48
Unit 2	9.05	2.55	59.64	18.99	20.56
Unit 3	14.28	3.48	15.33	22.01	6.19
Unit 4	29.70	2.09	5.72	16.01	6.66
Unit 5	57.95	4.43	150.07	0.05	111.00
Peaker Turbine	0.10	0.22	0.09	0.70	0.57
Total	135.25	45.19	277.65	77.76	166.45
2-yr Rolling Avg.	NA	90.22	161.42	177.70	122.10

Table A-3: VOC Pre-Project Actual Emissions by Year, ton/yr

	2009	2010	2011	2012	2013
Unit 1	1.80	1.15	2.17	4.46	1.29
Unit 2	1.23	0.38	2.36	4.66	1.08
Unit 3	1.95	0.80	2.40	5.51	1.90
Unit 4	7.81	2.57	3.83	12.81	4.71
Unit 5	11.53	6.52	6.39	17.52	7.43
Peaker Turbine	0.01	0.02	0.01	0.05	0.04
Total	24.33	11.42	17.15	45.02	16.45
2-yr Rolling Avg.	NA	17.87	14.29	31.09	30.73

Table A-4: $PM_{10}/PM_{2.5}$ Pre-Project Actual Emissions by Year, ton/yr

	2009	2010	2011	2012	2013
Unit 1	2.48	1.59	2.99	6.17	1.78
Unit 2	1.70	0.52	3.26	6.44	1.49
Unit 3	2.69	1.11	3.32	7.62	2.62
Unit 4	10.79	3.55	5.29	17.70	6.51
Unit 5	15.93	9.00	8.83	24.22	10.27
Peaker Turbine	0.02	0.05	0.02	0.15	0.13
Total	33.63	15.81	23.71	62.29	22.80
2-yr Rolling Avg.	NA	24.72	19.76	43.00	42.55

Table A-5: SOx Pre-Project Actual Emissions by Year, ton/yr

	2009	2010	2011	2012	2013
Unit 1	0.23	0.15	0.28	0.58	0.17
Unit 2	0.16	0.05	0.31	0.61	0.14
Unit 3	0.25	0.10	0.31	0.72	0.25
Unit 4	1.01	0.33	0.50	1.66	0.61
Unit 5	1.50	0.85	0.83	2.28	0.96
Peaker Turbine	0.00	0.01	0.00	0.02	0.01
Total	3.16	1.49	2.23	5.86	2.14
2-yr Rolling Avg.	NA	2.32	1.86	4.04	4.00

Table A-6: NH_3 Pre-Project Actual Emissions by Year, ton/yr

	2009	2010	2011	2012	2013
Unit 1	0.19	0.12	0.45	0.74	0.17
Unit 2	0.28	0.11	1.03	1.54	0.55
Unit 3	0.43	0.30	0.75	2.00	0.89
Unit 4	1.55	0.61	1.07	4.86	1.67
Unit 5	0.76	1.56	1.16	8.24	1.01
Peaker Turbine	0.00	0.00	0.00	0.00	0.00
Total	3.22	2.71	4.46	17.37	4.29
2-yr Rolling Avg.	NA	2.96	3.59	10.92	10.83

Table A-7: Fuel Data Used in Emission Calculations, MMscf/yr

	2009	2010	2011	2012	2013
Unit 1	653.8	417.3	788.0	1622.8	467.5
Unit 2	448.6	136.5	858.5	1695.0	393.1
Unit 3	708.0	291.3	873.3	2004.7	690.4
Unit 4	2839.5	933.9	1392.2	4658.0	1714.4
Unit 5	4193.1	2369.5	2322.4	6372.5	2701.5
Peaker Turbine	6.5	14.8	5.6	46.0	37.5
Total	8849.6	4163.3	6240.1	16399.0	6004.4

Notes:
Units 1 through 5 refer to the existing EPS boilers

Table A-8: Gas Turbine Toxic Emission Calculations

							One Turbine			Six Turbines		
Pollutant	EF (lb/MMBtu)	Source	Controlled EF (lb/MMBtu)	Max Steady State Hourly (lb/hr)	Max Startups and shutdowns (lb/hr)	Max Commissioning (lb/hr)	Emissions (lb/hr)	Emissions (lb/yr) with commissioning	Emissions (lb/yr)	Emissions (lb/hr)	Emissions (lb/yr) with commissioning	Emissions (lb/yr)
Ammonia,	6.81E-03	District/AP-42	6.81E-03	6.70E+00	6.70E+00	6.70E+00	6.70E+00	1.81E+04	1.81E+04	4.02E+01	1.09E+05	1.09E+05
Propylene	7.63E-04	CATEF	3.82E-04	3.76E-01	1.07E+00	1.18E+00	1.18E+00	1.46E+03	1.29E+03	7.05E+00	8.77E+03	7.75E+03
Acetaldehyde	4.00E-05	District/AP-42	2.00E-05	1.97E-02	5.60E-02	6.16E-02	6.16E-02	7.66E+01	6.77E+01	3.70E-01	4.60E+02	4.06E+02
Acrolein	6.40E-06	District/AP-42	3.20E-06	3.15E-03	8.96E-03	9.86E-03	9.86E-03	1.23E+01	1.08E+01	5.91E-02	7.35E+01	6.50E+01
Benzene	1.20E-05	District/AP-42	6.00E-06	5.90E-03	1.68E-02	1.85E-02	1.85E-02	2.30E+01	2.03E+01	1.11E-01	1.38E+02	1.22E+02
1,3-Butadiene	4.30E-07	District/AP-42	2.15E-07	2.12E-04	6.02E-04	6.62E-04	6.62E-04	8.23E-01	7.27E-01	3.97E-03	4.94E+00	4.36E+00
Ethylbenzene	3.20E-05	District/AP-42	1.60E-05	1.57E-02	4.48E-02	4.93E-02	4.93E-02	6.13E+01	5.41E+01	2.96E-01	3.68E+02	3.25E+02
Formaldehyde	9.08E-04	CATEF	4.54E-04	4.47E-01	1.27E+00	1.40E+00	1.40E+00	1.74E+03	1.54E+03	8.39E+00	1.04E+04	9.21E+03
n-Hexane	2.56E-04	CATEF	1.28E-04	1.26E-01	3.59E-01	3.95E-01	3.95E-01	4.91E+02	4.34E+02	2.37E+00	2.95E+03	2.60E+03
Naphthalene	1.64E-06	District/AP-42	8.22E-07	8.09E-04	2.30E-03	2.53E-03	2.53E-03	3.15E+00	2.78E+00	1.52E-02	1.89E+01	1.67E+01
PAH Total (individually below)	2.30E-06	CATEF	1.15E-06	1.13E-03	3.22E-03	3.54E-03	3.54E-03	4.40E+00	3.89E+00	2.12E-02	2.64E+01	2.33E+01
Acenaphthene	1.88E-08	CATEF	9.41E-09	9.26E-06	2.63E-05	2.90E-05	2.90E-05	3.60E-02	3.18E-02	1.74E-04	2.16E-01	1.91E-01
Acenaphthlyene	1.46E-08	CATEF	7.28E-09	7.16E-06	2.04E-05	2.24E-05	2.24E-05	2.79E-02	2.46E-02	1.35E-04	1.67E-01	1.48E-01
Anthracene	3.35E-08	CATEF	1.67E-08	1.65E-05	4.68E-05	5.15E-05	5.15E-05	6.41E-02	5.66E-02	3.09E-04	3.84E-01	3.40E-01
Benzo(a)anthracene	2.24E-08	CATEF	1.12E-08	1.10E-05	3.13E-05	3.45E-05	3.45E-05	4.28E-02	3.78E-02	2.07E-04	2.57E-01	2.27E-01
Benzo(a)pyrene	1.38E-08	CATEF	6.88E-09	6.77E-06	1.93E-05	2.12E-05	2.12E-05	2.64E-02	2.33E-02	1.27E-04	1.58E-01	1.40E-01
Benzo(e)pyrene	5.39E-10	CATEF	2.69E-10	2.65E-07	7.54E-07	8.30E-07	8.30E-07	1.03E-03	9.11E-04	4.98E-06	6.19E-03	5.47E-03
Benzo(b)fluoranthrene	1.12E-08	CATEF	5.59E-09	5.50E-06	1.57E-05	1.72E-05	1.72E-05	2.14E-02	1.89E-02	1.03E-04	1.29E-01	1.14E-01
Benzo(k)fluoranthrene	1.09E-08	CATEF	5.45E-09	5.36E-06	1.52E-05	1.68E-05	1.68E-05	2.09E-02	1.84E-02	1.01E-04	1.25E-01	1.11E-01
Benzo(g,h,i)perylene	1.36E-08	CATEF	6.78E-09	6.67E-06	1.90E-05	2.09E-05	2.09E-05	2.60E-02	2.29E-02	1.25E-04	1.56E-01	1.38E-01
Chrysene	2.50E-08	CATEF	1.25E-08	1.23E-05	3.49E-05	3.84E-05	3.84E-05	4.78E-02	4.22E-02	2.31E-04	2.87E-01	2.53E-01
Dibenz(a,h)anthracene	2.33E-08	CATEF	1.16E-08	1.14E-05	3.26E-05	3.58E-05	3.58E-05	4.46E-02	3.94E-02	2.15E-04	2.67E-01	2.36E-01
Fluoranthene	4.28E-08	CATEF	2.14E-08	2.10E-05	5.99E-05	6.59E-05	6.59E-05	8.19E-02	7.23E-02	3.95E-04	4.91E-01	4.34E-01
Fluorene	5.74E-08	CATEF	2.87E-08	2.83E-05	8.04E-05	8.85E-05	8.85E-05	1.10E-01	9.71E-02	5.31E-04	6.60E-01	5.83E-01
Indeno(1,2,3-cd)pyrene	2.33E-08	CATEF	1.16E-08	1.14E-05	3.26E-05	3.58E-05	3.58E-05	4.46E-02	3.94E-02	2.15E-04	2.67E-01	2.36E-01
Phenanthrene	3.10E-07	CATEF	1.55E-07	1.52E-04	4.34E-04	4.77E-04	4.77E-04	5.93E-01	5.24E-01	2.86E-03	3.56E+00	3.15E+00
Pyrene	2.74E-08	CATEF	1.37E-08	1.35E-05	3.84E-05	4.22E-05	4.22E-05	5.25E-02	4.64E-02	2.53E-04	3.15E-01	2.78E-01
Toluene	1.30E-04	District/AP-42	6.50E-05	6.40E-02	1.82E-01	2.00E-01	2.00E-01	2.49E+02	2.20E+02	1.20E+00	1.49E+03	1.32E+03
Xylenes	6.40E-05	District/AP-42	3.20E-05	3.15E-02	8.96E-02	9.86E-02	9.86E-02	1.23E+02	1.08E+02	5.91E-01	7.35E+02	6.50E+02

Notes:

PAH compounds that are not listed individually in District Rule 1200 are not included in this analysis.

Factors converted from lb/MMscf to lb/MMBtu assuming 1010 btu/scf HHV.

Includes 4 startup/shutdown hours per day, 400 startups/shutdowns per year.

For CATEF-factors, mean values were selected and if multiple factors given for an individual compound, the lowest levels were selected for analysis.

Table A-9: Metal Emissions from Water Injection

Water usage (single engine)	
23723	lb/hr
2844.5	gal/hr
7680108	gal/yr

			With Polishing						No Polishing					
Compound	Conc. After RO	Conc. After Polishing	Emissions (single engine)			Emissions (six engines)			Emissions (single engine)			Emissions (six engines)		
	ug/L	ug/L	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr	lb/hr	lb/day	lb/yr
TDS	20000	5000	0.12	2.85	320.43	0.71	17.09	1922.57	0.475	11.4	1281.7	2.85	68.4	7690.3
Arsenic	0.8	0.008	1.90E-07	4.56E-06	5.13E-04	1.14E-06	2.73E-05	3.08E-03	1.9E-05	4.56E-04	5.13E-02	1.14E-04	2.73E-03	3.08E-01
Cadmium	0.1	0.001	2.37E-08	5.70E-07	6.41E-05	1.42E-07	3.42E-06	3.85E-04	2.37E-06	5.7E-05	6.41E-03	1.42E-05	3.42E-04	3.85E-02
Chromium	0.01	0.0001	2.37E-09	5.70E-08	6.41E-06	1.42E-08	3.42E-07	3.85E-05	2.37E-07	5.7E-06	6.41E-04	1.42E-06	3.42E-05	3.85E-03
Copper	0.06	0.0006	1.42E-08	3.42E-07	3.85E-05	8.54E-08	2.05E-06	2.31E-04	1.42E-06	3.42E-05	3.85E-03	8.54E-06	2.05E-04	2.31E-02
Manganese	1.6	0.016	3.80E-07	9.11E-06	1.03E-03	2.28E-06	5.47E-05	6.15E-03	3.8E-05	9.11E-04	1.03E-01	2.28E-04	5.47E-03	6.15E-01
Mercury	0.2	0.002	4.75E-08	1.14E-06	1.28E-04	2.85E-07	6.84E-06	7.69E-04	4.75E-06	1.14E-04	1.28E-02	2.85E-05	6.84E-04	7.69E-02
Selenium	0.01	0.0001	2.37E-09	5.70E-08	6.41E-06	1.42E-08	3.42E-07	3.85E-05	2.37E-07	5.7E-06	6.41E-04	1.42E-06	3.42E-05	3.85E-03
Nickel	0.06	0.0006	1.42E-08	3.42E-07	3.85E-05	8.54E-08	2.05E-06	2.31E-04	1.42E-06	3.42E-05	3.85E-03	8.54E-06	2.05E-04	2.31E-02
Lead	0.01	0.0001	2.37E-09	5.70E-08	6.41E-06	1.42E-08	3.42E-07	3.85E-05	2.37E-07	5.7E-06	6.41E-04	1.42E-06	3.42E-05	3.85E-03
Sulfates	5000	50	1.19E-03	2.85E-02	3.20	7.12E-03	0.17	19.2	0.119	2.85	320.4	0.71	17.1	1922.6
Fluorides	20	0.2	4.75E-06	1.14E-04	1.28E-02	2.85E-05	6.84E-04	7.69E-02	0.000475	1.14E-02	1.28	2.85E-03	6.84E-02	7.69

Notes:

Emissions assuming no polishing were used for health risk assessment.

Emissions with polishing assume 99% removal (most Applicant supplied levels are below MDLs).

TDS is based on design value for the engine listed by manufacturer rather than water analysis.

Calculations assume 8.34 lb/gal, 3.785 L/gal for water.

Calculations are based on 100% load, average conditions.

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Table A-10: Gas Turbine GHG Calculations

Maximum Hourly Fuel Input (per turbine, HHV)

984 MMBtu/hr

Permitted Limits (per engine)

2700 hr/yr

Gas Turbine GHG Emission Rates				
	kg/MMBtu	lb/MMBtu	GWP	ton CO_2e/MMBtu
CO_2	53.06	116.98	1	5.85E-02
CH4	1.00E-03	2.20E-03	25	2.76E-05
N_2O	1.00E-04	2.20E-04	298	3.28E-05
SF6	NA	NA	22800	NA

Gas Turbine GHG Emission Calculations				
	US Ton/yr		MT/yr	
	Single	All Turbines	Single	All Turbines
CO2	155392	932355	140970	845819
CH4	73.2	439.3	66.4	398.5
N2O	87.3	523.6	79.2	475.0
Total	155553	933318	141115	846692

Table A-11: Diesel Engine GHG Calculations

	Power	Fuel Rate (gal/hr)
Fire pump	327	14.8
Emergency	779	35.9

Standard GHG emission rates				
	kg/MMBtu	lb/MMBtu	GWP	ton CO2e/MMBtu
CO2	73.96	163.0537	1	8.15 E-02
CH4	3.00E-03	0.0066139	25	8.27E-05
N_2O	6.00E-04	0.0013228	298	1.97E-04

Greenhouse Gas Calculations (ton CO_2e/yr)				
	CO_2	CH_4	N_2O	Total
Fire pump	8.3	0.008	0.020	8.3
Emergency	20.0	0.020	0.048	20.1
Total	28.3	0.029	0.1	28.4

Table A-12: Circuit Breaker SF_6 GHG Calculations

Type of Breaker	No. Units	Total SF_6 (lb)	Leakage Rate (fraction/yr)	lb SF_6/yr	ton CO_2e/yr	metric ton CO_2e/yr
Small	6	230	0.005	6.9	78.7	71.5
Large	2	500	0.005	5	57.0	51.8
Total		2380		11.9	135.7	123.3

Notes:

Gas turbine emissions assume 2700 hr/yr/turbine at full load.

Engine emissions assume 50 hr/yr for maintenance and testing at full load.

Diesel assumed to contain 137,000 Btu/gal HHV.

Table A-13: Actual Emission Reductions Needed Based on Commissioning Schedule (ton/yr)

	NOx	CO	VOC	SO2	(PM_{10})	($PM_{2.5}$)
1 Turbine started (PTE)	14.30	13.01	4.22	0.93	4.73	4.73
Actual Reduction needed for 1 Turbine	None	None	None	None	None	NA
2 Turbine started (PTE)	28.45	25.97	8.19	1.86	9.45	9.45
Actual Reduction needed for 2 Turbine	**3.6**	None	None	None	None	NA
3 Turbine started (PTE)	42.61	38.94	12.16	2.79	14.18	14.18
Actual Reduction needed for 3 Turbine	**17.7**	None	None	None	None	NA
4 Turbine started (PTE)	56.76	51.90	16.12	3.72	18.90	18.90
Actual Reduction needed for 4 Turbine	**31.9**	None	None	None	**4.00**	NA
5 Turbine started (PTE)	70.91	64.86	20.09	4.65	23.63	23.63
Actual Reduction needed for 5 Turbine	**46.0**	None	None	None	**8.73**	NA
6 Turbine started (PTE)	84.80	77.83	24.06	5.59	28.35	28.35
Actual Reduction needed for 6 Turbines	**59.9**	None	None	None	**13.45**	NA

Notes:

Table shows the PTE of the equipment with the indicated number of turbines operating (includes emissions from ancillary equipment).

Actual reductions needed are calculated based on the number of turbines that have started up to ensure that the contemporaneous emission increase does not exceed the threshold for a major modification or PSD modification of the stationary source

Table A-14: Fire Pump Engine Emission Calculations

FROM APPLICATION: Application No.: Fire Pump Company ID No.: SITE-00195

Applicant: Cabrillo Power I LLC

Make: Clarke/John Deere Model: JW6H-UFADF0

Max.Power: 327 bhp Fuel Rate: 14.8 gal/hr Driven Device: Fire Pump

Equipment (y or n): Turbo: y Aftercooled: y Retard: ? EPA Engine Family Number DJDXL09.0114

Schedule: 1.0 ophr/day 1 opday/wk 52 opwk/yr 52 opday/yr 50 ophr/yr

CERTIFIED EMISSION RATES: Ref. John Deere emissions data sheet

NOX	1.87	lb/ophr	2.60	gm/hp-ophr	#	ppmv, 15% O2
CO	0.50	lb/ophr	0.70	gm/hp-ophr	#	ppmv, 15% O2
NMHC	0.07	lb/ophr	0.10	gm/hp-ophr	26	ppmv, 15% O2
PM	0.08	lb/ophr	0.11	gm/hp-ophr	NA	ppmv, 15% O2
SOx	0.0031	lb/ophr	NA	gm/hp-ophr	#	ppmv, 15% O2

ALTERNATIVE EMISSION RATES: Ref. Use only if different emissions provided by engine manufacturer than the certified emission rates

NOX		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal
CO		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal
NMHC		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal
PM		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal
SOx		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal

WHICH SET OF EMISSION FACTORS ARE CONSIDERED TO BE MOST REPRESENTATIVE? Certified

REPRESENTATIVE EMISSIONS:

NOX	1.8743	lb/ophr x	1.0	ophr/day =	1.87	lb/day	x 50	opday/yr ÷ 2000 lb/ton =	0.05	ton/yr
CO	0.5046	lb/ophr			0.50	lb/day			0.01	ton/yr
NMHC	0.0721	lb/ophr			0.07	lb/day			0.00	ton/yr
PM	0.0793	lb/ophr			0.08	lb/day			0.002	ton/yr
SOX	0.0031	lb/ophr			0.00	lb/day			0.00	ton/yr

14.8 gallons diesel per hour 14.8 gallons diesel per day exhaust flow rate = 24103 dscf/hr, 12% CO2

PM concentration = 0.023 grains/dscf, 12% CO2 ==> **pass Rule 53**

COMMENTS: Calculation Constants: standard conditions are 68°F & 14.7 psia; #2 diesel fuel density is 7.05 lb/gal, and gross heat of combustion (HHV) is 19,433 btu/lb and 137,000 btu/gal; engine exhaust is 639 dscf/lb fuel @ 15% O2 (231 dscf/lb fuel @ 12% CO2); assume all fuel used is ultra low sulfur diesel (15 ppmw).

Table A-15: Emergency Engine Emission Calculations

FROM APPLICATION: Application No.: Emergency Company ID No.: 1982-SITE-00195

Applicant: Cabrillo Power I LLC

Make: Caterpillar Model: C15 ATAAC

Max.Power: 779 bhp Fuel Rate: 35.9 gal/hr Driven Device: Em. Generator 500 kW

Equipment (y or n): Turbo: y Aftercooled: y Retard: ? EPA Engine Family Number ECPXL15.2HZA

Schedule: 1.0 ophr/day 1 opday/wk 52 opwk/yr 52 opday/yr 50 ophr/yr

CERTIFIED EMISSION RATES: Ref. EPA Database

NOX	3.84	lb/ophr	2.24	gm/hp-ophr	198	ppmv, 15% O2
CO	1.15	lb/ophr	0.67	gm/hp-ophr	98	ppmv, 15% O2
NMHC	0.13	lb/ophr	0.07	gm/hp-ophr	19	ppmv, 15% O2
PM	0.09	lb/ophr	0.05	gm/hp-ophr	NA	ppmv, 15% O2
SOx	0.0076	lb/ophr	NA	gm/hp-ophr	0.3	ppmv, 15% O2

ALTERNATIVE EMISSION RATES: Ref. Use only if different emissions provided by engine manufacturer than the certified emission rates

NOX		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal
CO		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal
NMHC		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal
PM		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal
SOx		lb/ophr		lb/hp-ophr		gm/hp-ophr	lb/Mgal

WHICH SET OF EMISSION FACTORS ARE CONSIDERED TO BE MOST REPRESENTATIVE? Certified

REPRESENTATIVE EMISSIONS:

NOX	3.8435	lb/ophr x	1.0	ophr/day =	3.84	lb/day	x	50	opday/yr ÷ 2000 lb/ton =	0.10	ton/yr
CO	1.1530	lb/ophr			1.15	lb/day				0.03	ton/yr
NMHC	0.1281	lb/ophr			0.13	lb/day				0.00	ton/yr
PM	0.0897	lb/ophr			0.09	lb/day				0.002	ton/yr
SOX	0.0076	lb/ophr			0.01	lb/day				0.00	ton/yr

35.9 gallons diesel per hour 35.9 gallons diesel per day exhaust flow rate = 58465 dscf/hr, 12% CO2

PM concentration = 0.011 grains/dscf, 12% CO2 ==> **pass Rule 53**

COMMENTS: Calculation Constants: standard conditions are 68°F & 14.7 psia; #2 diesel fuel density is 7.05 lb/gal, and gross heat of combustion (HHV) is 19,433 btu/lb and 137,000 btu/gal; engine exhaust is 639 dscf/lb fuel @ 15% O2 (231 dscf/lb fuel @ 12% CO2); assume all fuel used is ultra low sulfur diesel (15 ppmw).

Appendix B: Health Risk Assessment Report

Rule 1200 Health Risk Assessment Report

Site ID:	333A
Application:	003482
Project Engineer:	Steven Moore
Toxics Risk Analyst:	Michael Kehetian
HRA Tools Used:	AERMOD / HARP On-Ramp / HARP (1.4f)
Report Date:	November 21, 2014

Draft Health Risk Assessment (HRA) evaluation for the Amended Carlsbad Energy Center Project (CECP)

An updated health risk assessment (HRA) was evaluated for the Amended Carlsbad Energy Center Project (CECP) and submitted by Sierra Research. The amended project is for an approximately 600 megawatt (MW) power plant consisting of six General Electric LMS100 natural gas simple-cycle turbines each with a maximum firing rate of 983.6 MMBtu/hr. In addition, the project will include a diesel emergency generator and fire pump engine.

The following review references supporting documentation contained in the Amended CECP California Energy Commission application (07-AFC-06C), along with additional supplemental information requested by the District. The HRA was reviewed for adherence to the Office of Environmental Health Hazard Assessment (OEHHA), Air Resources Board (ARB), and District Rule 1200 guidelines.

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

- Six GE LMS natural gas simple-cycle turbines with a combined power output of 632 MW. The turbines are proposed to be equipped with an oxidation catalyst to control carbon monoxide and volatile organic compounds (VOC) thereby reducing toxic air contaminant (TAC) emissions by at least 50% during normal operations.

- One diesel emergency generator rated at 779 brake horsepower (bhp) and a fire pump engine rated at 327 bhp.

The operating scenarios evaluated to determine the maximum potential health impacts include acute risk from commissioning startups, shoreline and inversion breakup fumigation, and cancer and chronic risk from normal full load operations and for the commissioning year.

- Annual Emissions - Each turbine operates for 1900 hours at full load plus 800 hours of startups and shutdowns with the diesel emergency and firepump engine emissions based on 100 hours of operation each per year.

- Hourly Emissions – Each turbine has one startup for 25 minutes with the remainder of the hour at full load. A shutdown for each turbine is 13 minutes with the remainder of the hour at full load with the diesel and firepump engines operating at full load.

- Commissioning – Each turbine operates for 213 hours for the first year.

Worst-Case Potential Health Impacts

Normal Operations

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index	8-Hour Health Hazard Index
Maximum Exposed Individual Resident	0.065	0.0005	0.016	N/A
Maximum Exposed Individual Worker	0.45	0.0015	0.027	2.5E-05
Point of Maximum Impact	2.30	0.0015	0.020	2.5E-05

Gas Turbine Startups

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.09

Gas Turbine Commissioning (Annual)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	0.0074	0.0001	N/A

Gas Turbine Commissioning (Hourly)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.078

Gas Turbine Inversion Breakup Fumigation (Normal Operations)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.014

Gas Turbine Inversion Breakup Fumigation (Commissioning)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.019

Gas Turbine Inversion Breakup Fumigation (Sync-Idle)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.043

Gas Turbine Inversion Breakup Fumigation (Startups)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.021

Gas Turbine Shoreline Fumigation (Normal Operations)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.044

Gas Turbine Shoreline Fumigation (Commissioning 10% Load)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.2

Gas Turbine Shoreline Fumigation (Commissioning)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.14

Gas Turbine Shoreline Fumigation (Startups)

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Point of Maximum Impact	N/A	N/A	0.16

The health impacts are less than the Rule 1200 significance level of a cancer risk of 1 in one million. For an incremental cancer risk of less than 1 in one million, toxic best available control technology (TBACT) is not required. Although the gas turbines are proposed to be equipped with an oxidation catalyst, which would likely be considered TBACT for this type of equipment, the diesel emergency generator and fire pump engines are not equipped with TBACT. Therefore, the project is limited with a cancer risk of up to 1 in one million. It should be noted that the District's conclusions are based on the maximum exposed individual resident or worker for cancer and chronic impacts which may or not be at the point of maximum impact.

Cancer risk at the Point of Maximum Impact (PMI) is due to diesel particulate matter. The location of the PMI is modeled grid receptor 7772, UTM NAD 83 Zone 11 coordinates 468813 E and 3666786 N.

Cancer risk at the Maximum Exposed Individual Resident (MEIR) is primarily due to diesel particulate matter (~52%), formaldehyde (~24%) and noninhalation exposure to benzo[a]pyrene (~10%) along with dibenz[a,h]anthracene (~6%). The location of the MEIR is modeled grid receptor 17658, UTM NAD 83 Zone 11 coordinates 469569 E and 3667371 N.

Cancer risk at the Maximum Exposed Individual Worker (MEIW) is due to diesel particulate matter. The location of the MEIW is modeled grid receptor 7772, UTM NAD 83 Zone 11 coordinates 468813 E and 3666786 N.

The chronic health hazard index (HHI) to the respiratory system is mainly due to diesel particulate matter (~97.2%). The chronic PMI HHI is located at grid receptor 7772, 468813 E and 3666786 N.

Acute risk to the eye endpoint is due to primarily formaldehyde (~70%) and ammonia (~18%). The acute PMI HHI is located at grid receptor 14092, 481950 E and 3669640 N.

Emission Factors

Emission factors reference the U.S. EPA AP-42 (Table 3.1-3) and California Air Toxic Emission Factor (CATEF) database for toxic compounds. The turbines are proposed to be equipped with an oxidation catalyst reducing the emission factors by 50% during normal operations. The emission factor for ammonia was calculated based on the proposed permit limit.

Toxic Air Contaminant (TAC)	Emission Factor Uncontrolled (lb/MMBtu)	Source	Emission Factor Controlled (lb/MMBtu)
ACETALDEHYDE	4.00E-05	AP-42	2.00E-05
ACROLEIN	6.42E-06	AP-42	3.21E-06
AMMONIA	6.87E-03	SDAPCD	6.87E-03
BENZENE	1.20E-05	AP-42	5.99E-06
BUTADIENE, 1,3-	4.30E-07	AP-42	2.15E-07
ETHYL BENZENE	3.20E-05	AP-42	1.60E-05
FORMALDEHYDE	9.00E-04	CATEF	4.50E-04
HEXANE-N	2.54E-04	CATEF	1.27E-04
NAPHTHALENE	1.31E-06	AP-42	6.53E-07
PAHs			
ACENAPHTHENE	1.86E-08	CATEF	9.32E-09
ACENAPTHYENE	1.44E-08	CATEF	7.21E-09
ANTHRACENE	3.32E-08	CATEF	1.66E-08
BENZO[a]ANTHRACENE	2.22E-08	CATEF	1.11E-08
BENZO[a]PYRENE	1.36E-08	CATEF	6.82E-09
BENZO[e]PYRENE	5.34E-10	CATEF	2.67E-10
BENZO[b]FLUORANTHENE	1.11E-08	CATEF	5.54E-09
BENZO[k]FLUORANTHENE	1.08E-08	CATEF	5.40E-09
BENZO[g,h,i]PERYLENE	1.34E-08	CATEF	6.72E-09
CHRYSENE	2.48E-08	CATEF	1.24E-08
DIBENZ[a,h]ANTHRACENE	2.30E-08	CATEF	1.15E-08
FLUORANTHENE	4.24E-08	CATEF	2.12E-08
FLUORENE	5.70E-08	CATEF	2.85E-08
INDENO(1,2,3-cd)PYRENE	2.30E-08	CATEF	1.15E-08
PHENANTHRENE	3.08E-07	CATEF	1.54E-07
PYRENE	2.72E-08	CATEF	1.36E-08
PROPYLENE	7.56E-04	CATEF	3.78E-04
PROPYLENE OXIDE	2.90E-05	AP-42	1.45E-05
TOLUENE	1.31E-04	AP-42	6.53E-05
XYLENES	6.40E-05	AP-42	3.20E-05

Emissions – Normal Operations (Each Turbine, 1900 hours per year)

Toxic Air Contaminant	Emission Factor Controlled (lb/MMBtu)	Emissions (lb/hr)	Emissions (lb/yr)
ACETALDEHYDE	2.00E-05	1.97E-02	7.64E+01
ACROLEIN	3.21E-06	3.16E-03	1.23E+01
AMMONIA	6.87E-03	6.76E+00	1.82E+04
BENZENE	5.99E-06	5.89E-03	2.29E+01
BUTADIENE, 1,3-	2.15E-07	2.11E-04	8.21E-01
ETHYL BENZENE	1.60E-05	2.11E-04	6.11E+01
FORMALDEHYDE	4.50E-04	4.43E-01	1.72E+03
HEXANE-N	1.27E-04	1.25E-01	4.85E+02

NAPHTHALENE	6.53E-07	1.59E-03	2.49E+00
PAHs			
ACENAPHTHENE	9.32E-09	9.17E-06	3.56E-02
ACENAPTHYENE	7.21E-09	7.09E-06	2.75E-02
ANTHRACENE	1.66E-08	1.63E-05	6.34E-02
BENZO[a]ANTHRACENE	1.11E-08	1.09E-05	4.24E-02
BENZO[a]PYRENE	6.82E-09	6.71E-05	2.60E-02
BENZO[e]PYRENE	2.67E-10	6.50E-07	1.02E-03
BENZO[b]FLUORANTHENE	5.54E-09	1.35E-05	2.12E-02
BENZO[k]FLUORANTHENE	5.40E-09	5.31E-06	2.06E-02
BENZO[g,h,i]PERYLENE	6.72E-09	6.61E-06	2.57E-02
CHRYSENE	1.24E-08	1.22E-05	4.73E-02
DIBENZ[a,h]ANTHRACENE	1.15E-08	2.09E-05	4.39E-02
FLUORANTHENE	2.12E-08	2.80E-05	8.09E-02
FLUORENE	2.85E-08	1.13E-05	1.09E-01
INDENO(1,2,3-cd)PYRENE	1.15E-08	1.51E-04	4.39E-02
PHENANTHRENE	1.54E-07	1.34E-05	5.88E-01
PYRENE	1.36E-08	1.43E-02	1.44E+03
PROPYLENE	3.78E-04	3.72E-01	1.44E+03
PROPYLENE OXIDE	1.45E-05	1.43E-02	5.54E+01
TOLUENE	6.53E-05	6.42E-02	2.49E+02
XYLENES	3.20E-05	3.15E-02	1.22E+02

Hourly turbine TAC emissions during startup and shutdown are scaled up by a factor equal to 2.48 as a ratio of volatile emissions from normal operations to account for overall combustion conditions and limited/non-operational control from the oxidation catalyst. For commissioning, a factor equal to 2.0 as a ratio of volatile emissions from normal operations.

Emissions – Startup/Shutdown (Each Turbine, 800 hours per year)

Toxic Air Contaminant	Emission Factor (lb/MMBtu)	Emissions (lb/hr)
ACETALDEHYDE	4.95E-05	4.87E-02
ACROLEIN	7.95E-06	7.82E-03
AMMONIA	6.87E-03	6.76E+00
BENZENE	1.48E-05	1.46E-02
BUTADIENE, 1,3-	5.32E-07	5.24E-04
ETHYL BENZENE	3.96E-05	3.90E-02
FORMALDEHYDE	1.11E-03	1.10E+00
HEXANE-N	3.15E-04	3.09E-01
NAPHTHALENE	1.62E-06	1.59E-03
PAHs		
ACENAPHTHENE	2.31E-08	2.27E-05
ACENAPTHYENE	1.79E-08	1.76E-05
ANTHRACENE	4.11E-08	4.04E-05

BENZO[a]ANTHRACENE	2.75E-08	2.70E-05
BENZO[a]PYRENE	1.69E-08	1.66E-05
BENZO[e]PYRENE	6.61E-10	6.50E-07
BENZO[b]FLUORANTHENE	1.37E-08	1.35E-05
BENZO[k]FLUORANTHENE	1.34E-08	1.32E-05
BENZO[g,h,i]PERYLENE	1.66E-08	1.64E-05
CHRYSENE	3.07E-08	3.02E-05
DIBENZ[a,h]ANTHRACENE	2.85E-08	2.80E-05
FLUORANTHENE	5.25E-08	5.16E-05
FLUORENE	7.06E-08	6.94E-05
INDENO(1,2,3-cd)PYRENE	2.85E-08	2.80E-05
PHENANTHRENE	3.81E-07	3.75E-04
PYRENE	3.37E-08	3.31E-05
PROPYLENE	9.36E-04	9.21E-01
PROPYLENE OXIDE	1.62E-04	1.59E-01
TOLUENE	1.62E-04	1.59E-01
XYLENES	7.92E-05	7.79E-02

Emissions – Commissioning (Uncontrolled, Each Turbine, 213 hours per year)

Toxic Air Contaminant	Emission Factor (lb/MMBtu)	Emissions (lb/hr)
ACETALDEHYDE	4.00E-05	3.93E-02
ACROLEIN	6.42E-06	6.31E-03
AMMONIA	6.87E-03	6.76E+00
BENZENE	1.20E-05	1.18E-02
BUTADIENE, 1,3-	4.30E-07	4.23E-04
ETHYL BENZENE	3.20E-05	3.15E-02
FORMALDEHYDE	9.00E-04	8.85E-01
HEXANE-N	2.54E-04	2.50E-01
NAPHTHALENE	1.31E-06	1.28E-03
PAHs		
ACENAPHTHENE	1.86E-08	1.83E-05
ACENAPTHYENE	1.44E-08	1.42E-05
ANTHRACENE	3.32E-08	3.27E-05
BENZO[a]ANTHRACENE	2.22E-08	2.18E-05
BENZO[a]PYRENE	1.36E-08	1.34E-05
BENZO[e]PYRENE	5.34E-10	5.25E-07
BENZO[b]FLUORANTHENE	1.11E-08	1.09E-05
BENZO[k]FLUORANTHENE	1.08E-08	1.06E-05
BENZO[g,h,i]PERYLENE	1.34E-08	1.32E-05
CHRYSENE	2.48E-08	2.44E-05
DIBENZ[a,h]ANTHRACENE	2.30E-08	2.26E-05
FLUORANTHENE	4.24E-08	4.17E-05
FLUORENE	5.70E-08	5.61E-05
INDENO(1,2,3-cd)PYRENE	2.30E-08	2.26E-05
PHENANTHRENE	3.08E-07	3.03E-04

PYRENE	2.72E-08	2.68E-05
PROPYLENE	7.56E-04	7.44E-01
PROPYLENE OXIDE	2.90E-05	2.85E-02
TOLUENE	1.31E-04	1.28E-01
XYLENES	6.40E-05	6.30E-02

Emissions – Sync Idle (Each Turbine)

Toxic Air Contaminant	Emission Factor (lb/MMBtu)	Emissions (lb/hr)
ACETALDEHYDE	4.00E-05	6.16E-02
ACROLEIN	6.40E-06	9.86E-03
AMMONIA	6.81E-03	6.70E+00
BENZENE	1.20E-05	1.85E-02
BUTADIENE, 1,3-	4.30E-07	6.62E-04
ETHYL BENZENE	3.20E-05	4.93E-02
FORMALDEHYDE	9.08E-04	1.40E+00
HEXANE-N		
NAPHTHALENE	1.64E-06	2.53E-03
PAHs		
ACENAPHTHENE	1.88E-08	2.90E-05
ACENAPTHYENE	1.46E-08	2.24E-05
ANTHRACENE	3.35E-08	5.15E-05
BENZO[a]ANTHRACENE	2.24E-08	3.45E-05
BENZO[a]PYRENE	1.38E-08	2.12E-05
BENZO[e]PYRENE	5.39E-10	8.30E-07
BENZO[b]FLUORANTHENE	1.12E-08	1.72E-05
BENZO[k]FLUORANTHENE	1.09E-08	1.68E-05
BENZO[g,h,i]PERYLENE	1.36E-08	2.09E-05
CHRYSENE	2.50E-08	3.84E-05
DIBENZ[a,h]ANTHRACENE	2.33E-08	3.58E-05
FLUORANTHENE	4.28E-08	6.59E-05
FLUORENE	5.74E-08	8.85E-05
INDENO(1,2,3-cd)PYRENE	2.33E-08	3.58-05
PHENANTHRENE	3.10E-07	4.77E-04
PYRENE	2.74E-08	4.22E-05
PROPYLENE	7.63E-04	1.18E+00
TOLUENE	1.30E-04	2.00E-01
XYLENES	6.40E-05	9.86E-02

Emissions – Water Injection (Each Turbine)

Toxic Air Contaminant	Concentration After RO Control (ug/L)	Emissions (lb/hr)	Emissions (lb/yr)
ARSENIC	0.8	1.90E-05	5.13E-02
CADMIUM	0.1	2.37E-06	6.41E-03

CHROMIUM	0.01	2.37E-07	6.41E-04
COPPER	0.06	1.42E-06	3.85E-03
MANGANESE	1.6	3.80E-05	1.03E-01
MERCURY	0.2	4.75E-06	1.28E-02
SELENIUM	0.01	2.37E-07	6.41E-04
NICKEL	0.06	1.42E-06	3.85E-03
LEAD	0.01	2.37E-07	6.41E-04
SULFATES	5000	1.19E-01	3.20E+02
FLUORIDES	20	4.75E-04	1.28E+00

Emergency Generator

Diesel particulate emission factor (g/hp-hr)	0.03
Diesel Particulate Emissions (lbs/yr)	5.15
Engine horsepower (bhp)	779
Fuel Consumption (gal/hr)	35.9
Stack Height (ft)	70
Stack Diameter (ft)	0.45
Temperature deg F	1263
Exhaust Velocity (ft/sec)	322

Emergency Firepump

Diesel particulate emission factor (g/hp-hr)	0.11
Diesel Particulate Emissions (lbs/yr)	7.93
Engine horsepower (bhp)	327
Fuel Consumption (gal/hr)	14.8
Stack Height (ft)	20
Stack Diameter (ft)	0.5
Temperature deg F	842
Exhaust Velocity (ft/sec)	158

Emissions –Emergency Generator (Hourly, Acute Health Impacts)

Toxic Air Contaminant	Emission Factor (lb/1000 gal)	Emissions (lb/hr)
ACETALDEHYDE	7.83E-01	2.81E-02
ACROLEIN	3.39E-02	1.22E-03
ARSENIC COMPOUNDS	1.60E-03	5.74E-05
BENZENE	1.86E-01	6.69E-03
BUTADIENE, 1,3-	2.17E-01	7.79E-03
CADMIUM AND COMPOUNDS	1.50E-03	5.39E-05
CHLOROBENZENE	2.00E-04	7.18E-06
CHROMIUM (HEXAVALENT)	1.00E-04	3.59E-06
COPPER AND COMPOUNDS	4.10E-03	1.47E-04
ETHYL BENZENE	1.09E-02	3.91E-04
FORMALDEHYDE	1.73E+00	6.20E-02

HEXANE-N	2.69E-02	9.66E-04
HYDROCHLORIC ACID	1.86E-01	6.69E-03
LEAD & COMPOUNDS	8.30E-03	2.98E-04
MANGANESE AND COMPOUNDS	3.10E-03	1.11E-04
MERCURY AND COMPOUNDS	2.00E-03	7.18E-05
NAPHTHALENE	1.97E-02	7.07E-04
NICKEL AND NICKEL COMPOUNDS	3.90E-03	1.40E-04
POLYCYCLIC AROM. HC (PAH) [Treated as B(a)P for HRA]	3.62E-02	1.30E-03
PROPYLENE	4.67E-01	1.68E-02
SELENIUM AND COMPOUNDS	2.20E-03	7.90E-05
TOLUENE	1.05E-01	3.78E-03
XYLENES	4.24E-02	1.52E-03

Source: Acute TACs – Ventura County, 5/17/01.

Emergency Firepump – (Hourly, Acute Health Impacts)

Toxic Air Contaminant	Emission Factor (lb/1000 gal)	Emissions (lb/hr)
ACETALDEHYDE	7.83E-01	1.16E-02
ACROLEIN	3.39E-02	5.02E-04
ARSENIC COMPOUNDS	1.60E-03	2.37E-05
BENZENE	1.86E-01	2.76E-03
BUTADIENE, 1,3-	2.17E-01	3.21E-03
CADMIUM AND COMPOUNDS	1.50E-03	2.22E-05
CHLOROBENZENE	2.00E-04	2.96E-06
CHROMIUM (HEXAVALENT)	1.00E-04	1.48E-06
COPPER AND COMPOUNDS	4.10E-03	6.07E-05
ETHYL BENZENE	1.09E-02	1.61E-04
FORMALDEHYDE	1.73E+00	2.55E-02
HEXANE-N	2.69E-02	3.98E-04
HYDROCHLORIC ACID	1.86E-01	2.76E-03
LEAD & COMPOUNDS	8.30E-03	1.23E-04
MANGANESE AND COMPOUNDS	3.10E-03	4.59E-05
MERCURY AND COMPOUNDS	2.00E-03	2.96E-05
NAPHTHALENE	1.97E-02	2.92E-04
NICKEL AND NICKEL COMPOUNDS	3.90E-03	5.77E-05
POLYCYCLIC AROM. HC (PAH) [Treated as B(a)P for HRA]	3.62E-02	5.36E-04
PROPYLENE	4.67E-01	6.91E-03
SELENIUM AND COMPOUNDS	2.20E-03	3.26E-05
TOLUENE	1.05E-01	1.56E-03
XYLENES	4.24E-02	6.28E-04

Air Dispersion Modeling

The US Environmental Protection Agency (EPA) AERMOD Dispersion Model (Version 13350) was used to predict concentration impacts using an emissions rate input of 1 g/s with TAC concentrations then calculated by their emission rates and the modelled dilution factors.

The District's Monitoring & Technical Services (M&TS) Division provided the AERMET surface and profile preprocessor files used which included five years (2008-2012) of Camp Pendleton meteorological data.

For all health impacts for the refined modelling, the 2009 meteorological data set predicted the worst-case results by a small margin. Note, the gas turbine inversion breakup and shoreline fumigation acute maximum impact points are based on the more conservative SCREEN3 model runs.

The dispersion results, X/Q (ug/m^3)/(g/s), were imported into ARB's Hotspots Analysis Reporting Program (HARP, Version 1.4f) via HARP On-Ramp to calculate actual TAC concentrations and resulting health impacts.

The dispersion modeling included a course 250-meter spacing grid extending out 10 km to assess the extent of maximum impacts. Refined 10-meter resolution receptor grids surrounding the areas of maximum impacts in addition to 25-meter spacing along the facility fenceline property boundary is sufficiently dense.

Release Parameters – Modeled Operating Modes

Operating Mode	Ambient Temperature (deg F)	Exhaust Temperature (deg F)	Exhaust Velocity (m/s)
Cold 100% Load	44.5	763.7	35.95
Cold 25% Load	44.5	856.7	18.62
Hot 100% Load with Evaporation	96.0	813.1	34.97
Hot 100% Load without Evaporation	96.0	821.1	33.66
Hot 25% Load	96.0	920.2	17.71
Average 100% Load with Evaporation	60.3	779.1	36.32
Average 100% Load without Evaporation	60.3	781.7	36.29
Average 25% Load	60.3	854.2	18.57

Release Parameters – Normal Operations (Cold 100% Load)

Release Parameter	Value
Stack Height (ft)	90
Stack Diameter (ft)	13.5
Temperature deg F	763.7
Exhaust Velocity (fps)	117.94

Release Parameters – Sync-Idle (Inversion Breakup Fumigation)

Release Parameter	Value
Stack Height (ft)	90
Stack Diameter (ft)	13.5

Temperature deg F	982.31
Exhaust Velocity (fps)	29.8

Release Parameters – Commissioning 10% Load (Shoreline Fumigation)

Release Parameter	**Value**
Stack Height (ft)	90
Stack Diameter (ft)	13.5
Temperature deg F	982.31
Exhaust Velocity (fps)	61.0

Risk Calculations

The HRA was reviewed using ARB's Hotspots Analysis and Reporting Program (HARP), Version 1.4f, referencing the OEHHA Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments, August 2003.

- Inhalation Breathing Rates and Exposure Duration: For calculating residential cancer risk over 70 years with inhalation as one of the two dominant pathways, the ARB Derived (Adjusted) Analysis Method was used which incorporates the minimum 80th percentile breathing rate equal to 302 Liters/Kilogram-day in accordance with the recommended interim risk management policy for inhalation-based residential cancer risk.

- Worker cancer risk was calculated applying the OEHHA recommended default exposure frequency of 245 days per year for the duration of 40 years using the single point estimate breathing rate equal to 149 Liters/Kilogram-day for an 8-hour workday.

  In accordance with the OEHHA Guidance Manual, *Calculating Cancer Risk Using Different Exposure Durations*, Section 8.2.2, *B. Worker*, a ground level concentration (GLC) adjustment factor was not applied to calculate occupational cancer risk since potential emissions are continuous (24 hours a day, 7 days per week).

- Noninhalation Exposure: Cancer and chronic health impacts include the required noninhalation pathways of dermal contact and soil ingestion 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.

  In addition to the exposure pathways of dermal contact and soil ingestion, residential cancer risk conservatively includes the rural home grown produce pathway with a human ingestion fraction equal to 15%.

  The fish consumption pathway using the default fraction of 1.0 (fraction of ingested fish from contaminated source) was included in the analysis for the nearby lagoon.

- Deposition Rate: In accordance with the OEHHA Guidance Manual, *Criteria for Exposure Pathway Evaluation*, Section 5.2, noninhalation exposure used the OEHHA deposition rate equal to 0.05 meters per second, which conservatively assumes particulate matter of less than or equal to 10 microns in diameter (PM_{10}).

- For the refined AERMOD modelling, the acute hazard index in HARP was calculated using the conservative default simple concurrent maximum approach. At each receptor, the maximum hourly dispersion factors for the entire period are summed from all sources assuming these impacts occur simultaneously at the same location. The more refined approach processes the meteorological data hourly variation dispersion impacts from different sources which for a given receptor will not necessarily be at their maximums at the same time.

- On June 18, 2008, the Scientific Review Panel (SRP) approved OEHHA's Air Toxics Hot Spots Program Technical Support Document (TSD) for the Derivation of Noncancer Reference Exposure Levels (REL) as mandated by the Children's Environmental Health Protection Act of 1999. A newly added 8-hour hazard index was created. For this project and referencing the Consolidated Table of OEHHA and ARB Approved Risk Assessment Health Values updated on July 03, 2014, 8-hour RELs exist for acetaldehyde, acrolein, arsenic, benzene, butadiene, formaldehyde, manganese, mercury, and nickel. The 8-hour RELs are not target organ specific and the worst-case 8-hour hazard index calculated is the sum for all the listed chemicals using the 24-hour annual average meteorological data set period for the turbine normal operation and water injection emissions.

Appendix C: Air Quality Impact Assessment Report

AIR QUALITY IMPACT ANALYSIS

FINAL REVIEW REPORT

CARLSBAD ENERGY CENTER PROJECT
APPLICATION APCD2014-APP-003482

December 11, 2014

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1.0 INTRODUCTION

An Air Quality Impact Analysis (AQIA) was performed and submitted to the San Diego Air Pollution Control District (SDAPCD) for the Amended 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 by the applicant and modeled by the SDAPCD.

2.0 PROJECT DESCRIPTION

NRG Energy, Inc. is proposing to remove the five existing boilers at the Encina Power Station (Units 1 through 5) and install six new natural gas fired GE LMS 100 simple-cycle turbines, an emergency generator engine and a fire pump engine. The six new turbines will provide a total nominal generating capacity of 632 MW net.

3.0 AIR QUALITY IMPACT ANALYSIS

Dispersion modeling was conducted for normal, startup/shutdown and commissioning (Sync Idle and Dynamic Load Step 10) period emissions of NO_2, CO, SO_2, 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 (96 F), summer average temperature (74 F), annual average temperature (60.3 F) and extreme low temperature (44.5 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%, and 25% 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, which included the emergency engine and fire pump engine, as appropriate, was performed using EPA’s AERMOD (Version 14134) 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 shoreline fumigation and the breakup of the overnight inversions that can form. The inversion breakup special case is modeled as an extra precaution to avoid an exceedance of ambient air quality standards

under these special atmospheric conditions. Shoreline fumigation, on the other hand, is a likely phenomenon given the projects coastal location.

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 2010 through 2012 time period. The data was processed by the District using EPA's Aermet meteorological data processor (Version 14134) 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.

Table 3-1
CECP Amendment, Screening Modeling Inputs
(Per Gas Turbine)

Case	Amb Temp deg F	Stack height feet	Stack Height meters	Stack Diam feet	Stack Diam meters	Stack Flow wacfm	Stack Flow m^3/sec	Stack Vel ft/sec	Stack Vel m/sec	Stack Temp deg F	Stack Temp deg K
Cold 100% Load	44.5	90.0	27.43	13.5	4.11	1,012,885	478.09	117.94	35.95	763.7	679.65
Cold 25% Load	44.5	90.0	27.43	13.5	4.11	524,635	247.63	61.09	18.62	856.7	731.32
Hot 100% Load w/Evap.	96.0	90.0	27.43	13.5	4.11	985,287	465.07	114.72	34.97	813.1	707.09
Hot 100% load w/o Evap.	96.0	90.0	27.43	13.5	4.11	948,559	447.73	110.45	33.66	821.1	711.54
Hot 25% Load	96.0	90.0	27.43	13.5	4.11	499,004	235.53	58.10	17.71	920.2	766.59
Avg. 100% Load w/Evap.	60.3	90.0	27.43	13.5	4.11	1,023,515	483.11	119.18	36.32	779.1	688.21
Avg. 100% Load w/o Evap.	60.3	90.0	27.43	13.5	4.11	1,022,475	482.62	119.05	36.29	781.7	689.65
Avg. 25% Load	60.3	90.0	27.43	13.5	4.11	523,114	246.91	60.91	18.57	854.2	729.93
Commissioning		90.0	27.43	13.5	4.11	523,114	246.91	60.91	18.57	854.2	729.93
Startup/Shutdown/Startup		90.0	27.43	13.5	4.11	523,114	246.91	60.91	18.57	854.2	729.93
Cold 50% Load	44.5	90.0	27.43	13.5	4.11	692,949	327.08	80.69	24.59	800.5	700.09
Hot 50% Load	96.0	90.0	27.43	13.5	4.11	647,396	305.58	75.38	22.98	870.1	738.76
Avg. 50% Load	60.3	90.0	27.43	13.5	4.11	689,606	325.50	80.30	24.47	800.0	699.82
Sync-Idle Load		90.0	27.43	13.5	4.11	256,837	121.23	29.91	9.12	982.3	801.09

Table 3-1 continued
CECP Amendment, Screening Modeling Inputs
(Per Gas Turbine)

	NOx	CO	PM_{10}	SOx	NOx	CO	PM_{10}	SOx
Case	**lb/hr**	**lb/hr**	**lb/hr**	**lb/hr**	**g/sec**	**g/sec**	**g/sec**	**g/sec**
Cold 50% Load	5.30	5.2	3.5	1.22	0.668	0.655	0.441	0.154
Hot 50% Load	4.90	4.8	3.5	1.13	0.617	0.605	0.441	0.142
Avg. 50% Load	5.30	5.2	3.5	0.41	0.668	0.655	0.441	0.052
Sync-Idle Load	47.08	114.6	3.5	0.27	5.933	14.438	0.441	0.034
Hot 25% Load	3.20	3.10	3.50	0.74	0.403	0.391	0.441	0.093
Avg. 100% Load w/Evap.	9.00	8.70	3.50	2.07	1.134	1.096	0.441	0.260
Avg. 100% Load w/o Evap.	9.00	8.80	3.50	2.07	1.134	1.109	0.441	0.261
Avg. 25% Load	3.50	3.40	3.50	0.79	0.441	0.428	0.441	0.100
Commissioning	90.00	247.7	3.5	2.07	11.340	31.206	0.441	0.261
Startup/Shutdown/Startup	28.24	17.3	3.5	2.07	3.558	2.181	0.441	0.261
Cold 100% Load	8.90	8.60	3.50	2.04	1.121	1.084	0.441	0.257
Cold 25% Load	3.40	3.40	3.50	0.79	0.428	0.428	0.441	0.100
Hot 100% Load w/Evap.	8.30	8.10	3.50	1.91	1.046	1.021	0.441	0.241
Hot 100% load w/o Evap.	8.10	7.80	3.50	1.85	1.021	0.983	0.441	0.234

Table 3-2
CECP Amendment, Screening Level Modeling Impacts
(Combined Impacts for Six Gas Turbines)

Operating Mode	Conc. (ug/m^3) NO_2 1-hr	Conc. (ug/m^3) SO_2 1-hr	Conc. (ug/m^3) CO 1-hr	Conc. (ug/m^3) SO_2 3-hr	Conc. (ug/m^3) CO 8-hr	Conc. (ug/m^3) SO_2 24-hr	Conc. (ug/m^3) PM_{10} 24-hr	Conc. (ug/m^3) NO_2 Annual	Conc. (ug/m^3) SO_2 Annual	Conc. (ug/m^3) PM_{10} Annual
Cold 100% Load	20.512	4.701	19.821	2.990	7.116	0.595	1.021	0.215	0.049	0.084
Cold 25% Load	11.794	2.754	11.794	1.526	3.927	0.324	1.430	0.110	0.026	0.113
Hot 100% Load w/Evap.	19.106	4.398	18.645	2.798	6.694	0.557	1.020	0.200	0.046	0.084
Hot 100% load w/o Evap.	19.037	4.358	18.332	2.759	6.574	0.551	1.039	0.199	0.046	0.086
Hot 25% Load	11.281	2.609	10.928	1.443	3.629	0.306	1.449	0.104	0.024	0.114
Avg. 100% Load w/Evap.	20.462	4.699	19.780	2.999	7.109	0.596	1.009	0.215	0.049	0.084
Avg. 100% Load w/o Evap.	20.453	4.706	19.999	3.003	7.188	0.597	1.009	0.215	0.049	0.084
Avg. 25% Load	12.184	2.764	11.836	1.531	3.939	0.325	1.434	0.113	0.026	0.113
Commissioning	313.296	7.208	862.144	3.993	286.896	0.848	1.434	N/A	N/A	N/A
Startup/Shutdown/Startup	98.291	7.208	60.264	3.993	20.054	0.848	1.434	N/A	N/A	N/A
Cold 50% Load	15.223	3.515	14.935	2.077	4.902	0.409	1.168	N/A	N/A	N/A
Hot 50% Load	14.381	3.319	14.088	1.937	4.622	0.388	1.202	N/A	N/A	N/A
Avg. 50% Load	15.279	1.180	14.991	0.696	4.920	0.137	1.174	N/A	N/A	N/A
Sync-Idle Load	250.687	1.436	610.079	0.885	217.020	0.178	2.309	N/A	N/A	N/A

Table 3-3
CECP Amendment, APCD Refined Model Inputs for Normal Operations [a]

Averaging Period	Unit	Stack D	Stack H	Temp (K)	Ex. Flow (m3/s)	Ex. Vel. (m/s)	Emission rate (g/s)	Emission rate (lb/hr)
One Hour NOx	Unit 6	4.12	27.44	679.7	478.4	35.96	1.13	8.93
	Unit 7	4.12	27.44	679.7	478.4	35.96	1.13	8.93
	Unit 8	4.12	27.44	679.7	478.4	35.96	1.13	8.93
	Unit 9	4.12	27.44	679.7	478.4	35.96	1.13	8.93
	Unit 10	4.12	27.44	679.7	478.4	35.96	1.13	8.93
	Unit 11	4.12	27.44	679.7	478.4	35.96	1.13	8.93
	Firepump	0.152	6.098	723.15	0.882	48.31	0.236	1.87
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	0.484	3.84
One Hour CO	Unit 6	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 7	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 8	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 9	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 10	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 11	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Firepump	0.152	6.098	723.15	0.882	48.31	0.0636	0.505
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	0.145	1.15
One Hour SO2	Unit 6	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 7	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 8	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 9	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 10	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 11	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Firepump	0.152	6.098	723.15	0.882	48.31	3.94E-04	3.13E-03
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	9.57E-04	7.59E-03
Three Hour SO2	Unit 6	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 7	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 8	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 9	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 10	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 11	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Firepump	0.152	6.098	723.15	0.882	48.31	1.31E-04	1.04E-03
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	3.19E-04	2.53E-03

a. The fire pump and emergency engines are assumed to be operating a Full load for one hour for one-hour averaging times. For 3-, 8- and 24-hour averaging times engine emissions for one hour of operation are averaged over the averaging period. For annual emissions, engine emissions for 50 hours for each engine are averaged over one year.

Table 3-3, continued
CECP Amendment, APCD Refined Model Inputs for Normal Operations [a]

Averaging Period	Unit	Stack D	Stack H	Temp (K)	Ex. Flow (m3/s)	Ex. Vel. (m/s)	Emission rate (g/s)	Emission rate (lb/hr)
Eight Hours CO	Unit 6	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 7	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 8	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 9	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 10	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Unit 11	4.12	27.44	689.65	482.9	36.30	1.11	8.83
	Firepump	0.152	6.098	723.15	0.882	48.31	7.95E-03	6.31E-02
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	1.82E-02	1.44E-01
24-hr SO2	Unit 6	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 7	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 8	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 9	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 10	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 11	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Firepump	0.152	6.098	723.15	0.882	48.31	3.94E-04	3.13E-03
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	9.57E-04	7.59E-03
24-hr PM-10	Unit 6	4.12	27.44	766.59	235.7	17.71	0.63	5.00
	Unit 7	4.12	27.44	766.59	235.7	17.71	0.63	5.00
	Unit 8	4.12	27.44	766.59	235.7	17.71	0.63	5.00
	Unit 9	4.12	27.44	766.59	235.7	17.71	0.63	5.00
	Unit 10	4.12	27.44	766.59	235.7	17.71	0.63	5.00
	Unit 11	4.12	27.44	766.59	235.7	17.71	0.63	5.00
	Firepump	0.152	6.098	723.15	0.882	48.31	4.16E-04	3.30E-03
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	4.71E-04	3.74E-03
Annual NOx	Unit 6	4.12	27.44	689.65	482.9	36.30	0.407	3.23
	Unit 7	4.12	27.44	689.65	482.9	36.30	0.407	3.23
	Unit 8	4.12	27.44	689.65	482.9	36.30	0.407	3.23
	Unit 9	4.12	27.44	689.65	482.9	36.30	0.407	3.23
	Unit 10	4.12	27.44	689.65	482.9	36.30	0.407	3.23
	Unit 11	4.12	27.44	689.65	482.9	36.30	0.407	3.23
	Firepump	0.152	6.098	723.15	0.882	48.31	1.35E-03	1.07E-02
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	2.76E-03	2.19E-02

a. The fire pump and emergency engines are assumed to be operating a Full load for one hour for one-hour averaging times. For 3-, 8- and 24-hour averaging times engine emissions for one hour of operation are averaged over the averaging period. For annual emissions, engine emissions for 50 hours for each engine are averaged over one year.

Table 3-3, continued CECP Amendment, APCD Refined Model Inputs for Normal Operations [a]								
Averaging Period	**Unit**	**Stack D**	**Stack H**	**Temp (K)**	**Ex. Flow (m3/s)**	**Ex. Vel. (m/s)**	**Emission rate (g/s)**	**Emission rate (lb/hr)**
Annual SO2	Unit 6	4.12	27.44	689.65	482.9	36.30	0.0268	0.21
	Unit 7	4.12	27.44	689.65	482.9	36.30	0.0268	0.21
	Unit 8	4.12	27.44	689.65	482.9	36.30	0.0268	0.21
	Unit 9	4.12	27.44	689.65	482.9	36.30	0.0268	0.21
	Unit 10	4.12	27.44	689.65	482.9	36.30	0.0268	0.21
	Unit 11	4.12	27.44	689.65	482.9	36.30	0.0268	0.21
	Firepump	0.152	6.098	723.15	0.882	48.31	2.25E-06	1.79E-05
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	5.46E-06	4.33E-05
Annual PM-10	Unit 6	4.12	27.44	766.59	235.7	17.71	0.136	1.08
	Unit 7	4.12	27.44	766.59	235.7	17.71	0.136	1.08
	Unit 8	4.12	27.44	766.59	235.7	17.71	0.136	1.08
	Unit 9	4.12	27.44	766.59	235.7	17.71	0.136	1.08
	Unit 10	4.12	27.44	766.59	235.7	17.71	0.136	1.08
	Unit 11	4.12	27.44	766.59	235.7	17.71	0.136	1.08
	Firepump	0.152	6.098	723.15	0.882	48.31	5.70E-05	4.53E-04
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	6.45E-05	5.12E-04

a. The fire pump and emergency engines are assumed to be operating a Full load for one hour for one-hour averaging times. For 3-, 8- and 24-hour averaging times engine emissions for one hour of operation are averaged over the averaging period. For annual emissions, engine emissions for 50 hours for each engine are averaged over one year.

Table 3-4 CECP Amendment, APCD Model Inputs For Commissioning Dynamic Commissioning Load Step 10 [a]								
	Unit	**Stack D (m)**	**Stack H (m)**	**Temp (K)**	**Ex. Flow (m3/s)**	**Ex. Vel. (m/s)**	**Emission rate (g/s)**	**Emission rate (lb/hr)**
	Unit 6	4.12	27.44	689.65	482.9	36.30	11.34	90
	Unit 7	4.12	27.44	689.65	482.9	36.30	11.34	90
	Unit 8	4.12	27.44	689.65	482.9	36.30	11.34	90
	Unit 9	4.12	27.44	689.65	482.9	36.30	11.34	90
	Unit 10	4.12	27.44	689.65	482.9	36.30	11.34	90
	Unit 11	4.12	27.44	689.65	482.9	36.30	11.34	90
	Peaker	3.9	13.3	800.4	1472.0	23.8	0.95	7.5
NOx	Boilers	7.9	116.7	427.6	287.47	29.8	12.54	99.5
	Unit 6	4.12	27.44	689.65	482.9	36.30	31.21	247.7
	Unit 7	4.12	27.44	689.65	482.9	36.30	31.21	247.7
	Unit 8	4.12	27.44	689.65	482.9	36.30	31.21	247.7
	Unit 9	4.12	27.44	689.65	482.9	36.30	31.21	247.7
	Unit 10	4.12	27.44	689.65	482.9	36.30	31.21	247.7
	Unit 11	4.12	27.44	689.65	482.9	36.30	31.21	247.7
	Peaker	3.9	13.3	800.4	1472.0	23.8	1.20	9.5
CO	Boilers	7.9	116.7	427.6	287.47	29.8	36.24	287.6
	Unit 6	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 7	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 8	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 9	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 10	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Unit 11	4.12	27.44	689.65	482.9	36.30	0.261	2.07
	Peaker	3.9	13.3	800.4	1472.0	23.8	0.0839	0.7
SOx	Boilers	7.9	116.7	427.6	287.47	29.8	2.614	20.7
	Unit 6	4.12	27.44	689.65	482.9	36.30	0.630	5.00
	Unit 7	4.12	27.44	689.65	482.9	36.30	0.630	5.00
	Unit 8	4.12	27.44	689.65	482.9	36.30	0.630	5.00
	Unit 9	4.12	27.44	689.65	482.9	36.30	0.630	5.00
	Unit 10	4.12	27.44	689.65	482.9	36.30	0.630	5.00
	Unit 11	4.12	27.44	689.65	482.9	36.30	0.630	5.00
	Peaker	3.9	13.3	800.4	1472.0	23.8	0.298	2.4
PM-10	Boilers	7.9	116.7	427.6	287.47	29.8	9.271	73.6

a. The peaking turbine and boilers are assumed to be operating at full load

Table 3-5 CECP Amendment, APCD Model Inputs For Commissioning, Sync Idle [a]								
	Unit	**Stack D**	**Stack H**	**Temp (K)**	**Ex. Flow (m3/s)**	**Ex. Vel. (m/s)**	**Emission rate (g/s)**	**Emission rate (lb/hr)**
	Unit 6	4.12	27.44	801.1	121.23	9.1	5.935	47.1
	Unit 7	4.12	27.44	801.1	121.23	9.1	5.935	47.1
	Unit 8	4.12	27.44	801.1	121.23	9.1	5.935	47.1
	Unit 9	4.12	27.44	801.1	121.23	9.1	5.935	47.1
	Unit 10	4.12	27.44	801.1	121.23	9.1	5.935	47.1
	Unit 11	4.12	27.44	801.1	121.23	9.1	5.935	47.1
	Peaker	3.9	13.3	800.4	287.47	23.8	0.95	7.5
NOx	Boilers	7.9	116.7	427.6	1472.0	29.8	12.54	99.5
	Unit 6	4.12	27.44	801.1	121.23	9.1	14.44	114.6
	Unit 7	4.12	27.44	801.1	121.23	9.1	14.44	114.6
	Unit 8	4.12	27.44	801.1	121.23	9.1	14.44	114.6
	Unit 9	4.12	27.44	801.1	121.23	9.1	14.44	114.6
	Unit 10	4.12	27.44	801.1	121.23	9.1	14.44	114.6
	Unit 11	4.12	27.44	801.1	121.23	9.1	14.44	114.6
	Peaker	3.9	13.3	800.4	287.47	23.8	1.198	9.5
CO	Boilers	7.9	116.7	427.6	1472.0	29.8	36.24	287.6
	Unit 6	4.12	27.44	801.1	121.23	9.1	0.0342	0.27
	Unit 7	4.12	27.44	801.1	121.23	9.1	0.0342	0.27
	Unit 8	4.12	27.44	801.1	121.23	9.1	0.0342	0.27
	Unit 9	4.12	27.44	801.1	121.23	9.1	0.0342	0.27
	Unit 10	4.12	27.44	801.1	121.23	9.1	0.0342	0.27
	Unit 11	4.12	27.44	801.1	121.23	9.1	0.0342	0.27
	Peaker	3.9	13.3	800.4	287.47	23.8	0.0839	0.7
SOx	Boilers	7.9	116.7	427.6	1472.0	29.8	2.614	20.7
	Unit 6	4.12	27.44	801.1	121.23	9.1	0.630	5.00
	Unit 7	4.12	27.44	801.1	121.23	9.1	0.630	5.00
	Unit 8	4.12	27.44	801.1	121.23	9.1	0.630	5.00
	Unit 9	4.12	27.44	801.1	121.23	9.1	0.630	5.00
	Unit 10	4.12	27.44	801.1	121.23	9.1	0.630	5.00
	Unit 11	4.12	27.44	801.1	121.23	9.1	0.630	5.00
	Peaker	3.9	13.3	800.4	287.47	23.8	0.298	2.4
PM-10	Boilers	7.9	116.7	427.6	1472.0	29.8	9.271	73.6

a. The peaking turbine and boilers are assumed to be operating at full load

Table 3-6 CECP Amendment, APCD Model Inputs For Startup/Shutdown [a]								
	Unit	Stack D (m)	Stack H (m)	Temp (K)	Ex. Flow (m3/s)	Ex. Vel. (m/s)	Emission rate (g/s)	Emission rate (lb/hr)
One Hour NOx	Unit 6	4.12	27.44	729.93	246.9	18.6	3.5532	28.2
	Unit 7	4.12	27.44	729.93	246.9	18.6	3.5532	28.2
	Unit 8	4.12	27.44	729.93	246.9	18.6	3.5532	28.2
	Unit 9	4.12	27.44	729.93	246.9	18.6	3.5532	28.2
	Unit 10	4.12	27.44	729.93	246.9	18.6	3.5532	28.2
	Unit 11	4.12	27.44	729.93	246.9	18.6	3.5532	28.2
	Firepump	0.152	6.098	723.15	0.882	48.31	0.236	1.87
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	0.484	3.84
One Hour CO	Unit 6	4.12	27.44	729.93	246.9	18.6	2.18	17.3
	Unit 7	4.12	27.44	729.93	246.9	18.6	2.18	17.3
	Unit 8	4.12	27.44	729.93	246.9	18.6	2.18	17.3
	Unit 9	4.12	27.44	729.93	246.9	18.6	2.18	17.3
	Unit 10	4.12	27.44	729.93	246.9	18.6	2.18	17.3
	Unit 11	4.12	27.44	729.93	246.9	18.6	2.18	17.3
	Firepump	0.152	6.098	723.15	0.882	48.31	0.0636	0.505
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	0.145	1.15
One Hour SO2	Unit 6	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 7	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 8	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 9	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 10	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 11	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Firepump	0.152	6.098	723.15	0.882	48.31	3.94E-04	3.13E-03
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	9.57E-04	7.59E-03
Three Hour SO2	Unit 6	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 7	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 8	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 9	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 10	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Unit 11	4.12	27.44	729.93	246.9	18.6	0.159	1.26
	Firepump	0.152	6.098	723.15	0.882	48.31	1.31E-04	1.04E-03
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	3.19E-04	2.53E-03

a. The fire pump and emergency engines are assumed to be operating a Full load for one hour for one-hour averaging times. For 3-, 8- and 24-hour averaging times engine emissions for one hour of operation are averaged over the averaging period. For annual emissions, engine emissions for 50 hours for each engine are averaged over one year.

Table 3-6,continued CECP Amendment, APCD Model Inputs For Startup/Shutdown [a]								
	Unit	Stack D (m)	Stack H (m)	Temp (K)	Ex. Flow (m3/s)	Ex. Vel. (m/s)	Emission rate (g/s)	Emission rate (lb/hr)
Eight Hours CO	Unit 6	4.12	27.44	729.93	246.9	18.6	2.180	17.3
	Unit 7	4.12	27.44	729.93	246.9	18.6	2.180	17.3
	Unit 8	4.12	27.44	729.93	246.9	18.6	2.180	17.3
	Unit 9	4.12	27.44	729.93	246.9	18.6	2.180	17.3
	Unit 10	4.12	27.44	729.93	246.9	18.6	2.180	17.3
	Unit 11	4.12	27.44	729.93	246.9	18.6	2.180	17.3
	Firepump	0.152	6.098	723.15	0.882	48.31	7.95E-03	6.31E-02
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	1.82E-02	1.44E-01
24-hr SO2	Unit 6	4.12	27.44	729.93	246.9	18.6	0.261	1.26
	Unit 7	4.12	27.44	729.93	246.9	18.6	0.261	1.26
	Unit 8	4.12	27.44	729.93	246.9	18.6	0.261	1.26
	Unit 9	4.12	27.44	729.93	246.9	18.6	0.261	1.26
	Unit 10	4.12	27.44	729.93	246.9	18.6	0.261	1.26
	Unit 11	4.12	27.44	729.93	246.9	18.6	0.261	1.26
	Firepump	0.152	6.098	723.15	0.882	48.31	3.94E-04	3.13E-03
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	9.57E-04	7.59E-03
24-hr PM-10	Unit 6	4.12	27.44	729.93	246.9	18.6	0.63	5.00
	Unit 7	4.12	27.44	729.93	246.9	18.6	0.63	5.00
	Unit 8	4.12	27.44	729.93	246.9	18.6	0.63	5.00
	Unit 9	4.12	27.44	729.93	246.9	18.6	0.63	5.00
	Unit 10	4.12	27.44	729.93	246.9	18.6	0.63	5.00
	Unit 11	4.12	27.44	729.93	246.9	18.6	0.63	5.00
	Firepump	0.152	6.098	723.15	0.882	48.31	4.16E-04	3.30E-03
	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	4.71E-04	3.74E-03

a. The fire pump and emergency engines are assumed to be operating a Full load for one hour for one-hour averaging times. For 3-, 8- and 24-hour averaging times engine emissions for one hour of operation are averaged over the averaging period. For annual emissions, engine emissions for 50 hours for each engine are averaged over one year.

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 (Dynamic and Sync Idle) 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 (2010-2012) 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.

For NO_2 modeling, the Ozone Limiting (OLM) Group method was selected to determine predicted NO_2 concentrations. Ozone and NO_2 data from the Camp Pendleton monitoring station were used. The OLM AERMOD model option uses concurrent hourly ozone data to first determine the total predicted NO_2 impact (initial NO_2 plus converted from NO by reaction with ozone). The concurrent hourly NO_2 background values are then added to determine the maximum predicted NO_2 impact plus background for each hour at each receptor, and maximum for each year. The maximum 98th percentile (8th high in this case) impact plus background at each receptor for each year, and maximum for each year is then determined.

The following initial NO_2/NO_x ratios were assumed:

Turbines: 13% during normal operating hours
Turbines: 24% during hours that a startup/shutdown occurred
Turbines, 24% during commissioning tests when the SCR system is not operational
Emergency engine: 18%
Fire Pump engine: 14%

Table 4-1 summarizes the worst case background concentrations.

The maximum ground-level impacts at any location from normal operations and startup/shutdowns, considering standard meteorology, shoreline fumigation 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 Dynamic Commissioning Load Step 10 operating conditions.

Table 4-4 provides the summary of project modeled maximum impacts for Dynamic Commissioning Sync Idle operating conditions.

Table 4-5 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 4-6 provides a comparison of maximum modeled impacts during normal operation and PSD significant impact levels.

TABLE 4-1

MAXIMUM BACKGROUND CONCENTRATIONS [a], PROJECT AREA, 2010-2012 ($\mu g/m^3$)

	Averaging Time	2010	2011	2012
NO_2 (Camp Pendleton)	1-hour	**152**	124	115
	Annual	**17**	--	15
	1-hour 98th Percentile	**96**	87	87
SO_2 (San Diego)	1-hour	21	**34**	**--**
	24-hour	**8**	8	--
	Annual	**0**	-	-
CO (Escondido)	1-hour	4466	4008	**5039**
	8-hour	2863	2634	**4352**
PM_{10} (Escondido)	24-hour	**42**	40	33
	Annual	**21**	19	18
$PM_{2.5}$ (Escondido)	24-hour [b]	22	22	20
	Annual	10.5	10.4	**10.6**

Source: California Air Quality Data, California Air Resources Board website; EPA AIR Data website. Reported values have been rounded to the nearest $\mu g/m^3$.

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 2010 to 2012 98th percentile readings (21.3) was used to represent the background concentration.

TABLE 4-2

NORMAL OPERATION AIR QUALITY MODELING RESULTS FOR NEW EQUIPMENT

2010-2012 MODELED MAXIMUM CONCENTRATIONS (μg/m^3)

Pollutant	Averaging Time	Normal Operations AERMOD	Startup/Shutdown AERMOD	Fumigation SCREEN3	Shoreline Fumigation SCREEN3
Combined Impacts Turbines, Fire Pump, Emergency Engine					
NO_2	1-hour	209, f	209, f	4.8	33.9
	1-hour 98th P	165, f	165, f	-	-
	Annual	0.08	A	c	c
SO_2	1-hour	4.7	b	1.1	7.8
	3-hour	3.03	b	0.9	3.5
	24-hour	0.6	b	0.3	0.5
	Annual	0.005	b	c	c
CO	1-hour	38.8	61.0	4.6	32.7
	8-hour	7.2	20.9	2.6	6.2
$PM_{2.5}/PM_{10}$	24-hour	2.15, h	b	0.9	1.4
	Annual	0.036	b	c	c
Turbines Only					
NO_2	1-hour	153.0, f	169.4, f	4.8	33.9
	1-hour 98th P	97, f	102, f	-	-
	Annual	0.08	A	c	c
SO_2	1-hour	4.7	b	1.1	7.8
	3-hour	3.03	b	0.9	3.5
	24-hour	0.6	b	0.3	0.5
	Annual	0.005	a	c	c
CO	1-hour	20.1	61.0	4.6	32.7
	8-hour	7.2	20.9	2.6	6.2
$PM_{2.5}/PM_{10}$	24-hour	2.15	a	0.9	1.4
	Annual	0.036	a	c	c
Fire Pump and Emergency Engine					
NO_2	1-hour	209, f	209, f	e	e
	1-hour 98th P	165, f	165, f	e	e
	Annual	0.07	A	c	c
SO_2	1-hour	0.24	b	e	e
	3-hour	0.07	b	e	e
	24-hour	0.1	b	e	e
	Annual	0.0	a	c	c
CO	1-hour	38.8	38.8	e	e
	8-hour	3.6	3.6	e	e
$PM_{2.5}/PM_{10}$	24-hour	0.11, g,h	b	e	e
	Annual	0.003	a	c	c

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 and the release parameters used to evaluate normal operations are consistent with the release parameters used to evaluate startup and shutdown..

c. Not applicable, because shoreline fumigation and 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. NO_2 Impacts include background concentrations.

g. This impact is based on averaging one hour of emissions over 24-hours as an approximate method of addressing a typical operating scenario of engine testing of one hour per day. The District also performed supplemental modeling using 2012 meteorology data and assuming that the engine was operating at full load for every hour during each day. The maximum 24-hour average emission impact from this unlikely scenario, which would not be representative of typical engine testing, was 1.19 ug/m^3. Even this higher impact would not change this report's conclusion.

h. In 2012, the year of the maximum startup/shutdown 24-hour PM_{10} impact, the estimated impact of the fire pump and emergency engine at the turbines point of maximum impact is less than 0.01 ug/m^3.

TABLE 4-3

COMMISSIONING, DYNAMIC LOAD STEP 10

2010-2012 MODELED MAXIMUM CONCENTRATIONS (μg/m^3)

Pollutant	Averaging Time	Modeled Maximum Concentrations (μg/m^3)
Combined Impacts Turbines, Peaker, Boiler [b, d]		
NO_2[c]	1-hour	210.7
	1-hour 98th Percentile	127.8
	Annual	a
SO_2	1-hour	4.99
	3-hour	3.22
	24-hour	0.69
	Annual	a
CO	1-hour	567.4
	8-hour	204.7
$PM_{2.5}/PM_{10}$	24-hour	1.77
	Annual	a
Turbines Only		
NO_2[c]	1-hour	209.0
	1-hour 98th Percentile	126.6
	Annual	a
SO_2	1-hour	4.70
	3-hour	3.03
	24-hour	0.60
	Annual	a
CO	1-hour	563.5
	8-hour	202.7
$PM_{2.5}/PM_{10}$	24-hour	1.44
	Annual	a
Existing Peaker and Boiler		
NO_2[c]	1-hour	152.5
	1-hour 98th Percentile	98.9
	Annual	a
SO_2	1-hour	2.39
	3-hour	1.27
	24-hour	0.28
	Annual	a
CO	1-hour	33.2
	8-hour	8.1
$PM_{2.5}/PM_{10}$	24-hour	0.98
	Annual	a

a. Not applicable, because commissioning emissions are included in the modeling for annual average.

b. The emergency generator and fire pump engines are not included because these engines will not operate during CTG startups/shutdowns.

c. NO_2 Impacts include background concentrations.

d. The District does not typically model emissions from existing equipment (boilers and one peaking turbine). However they are included here as an extra precaution since they are anticipated to be operating to some extent during commissioning.

TABLE 4-4

COMMISSIONING, SYNC IDLE

2010-2012 MODELED MAXIMUM CONCENTRATIONS (μg/m^3)

Pollutant	Averaging Time	Modeled Maximum Concentrations (μg/m^3)
Combined Impacts Turbines, Peaker, Boiler		
NO_2[c]	1-hour	214.1
	1-hour 98th Percentile	140.5
	Annual	a
SO_2	1-hour	2.6
	3-hour	1.42
	24-hour	0.31
	Annual	a
CO	1-hour	664.0
	8-hour	219.1
$PM_{2.5}/PM_{10}$	24-hour	3.75
	Annual	a
Turbines Only		
NO_2[c]	1-hour	213.1
	1-hour 98th Percentile	138.2
	Annual	a
SO_2	1-hour	1.6
	3-hour	0.9
	24-hour	0.2
	Annual	a
CO	1-hour	658.6
	8-hour	217.3
$PM_{2.5}/PM_{10}$	24-hour	3.3
	Annual	a
Existing Peaker and Boiler		
NO_2[c]	1-hour	152.5
	1-hour 98th Percentile	98.9
	Annual	a
SO_2	1-hour	2.4
	3-hour	1.27
	24-hour	0.28
	Annual	a
CO	1-hour	33.2
	8-hour	8.1
$PM_{2.5}/PM_{10}$	24-hour	0.98
	Annual	a

a. Not applicable, because commissioning emissions are included in the modeling for annual average.

b. Not applicable, because these engines will not operate during CTG startups/shutdowns.

c. NO_2 Impacts include background concentrations.

TABLE 4-5

MODELED MAXIMUM PROPOSED PROJECT IMPACTS

2010-2012 MODELED MAXIMUM CONCENTRATIONS (μg/m^3)

Pollutant	Averaging Time	Maximum Project Impact (μg/m^3)	Maximum Background (μg/m^3)	Total Impact (μg/m^3)	State Standard (μg/m^3)	Federal Standard (μg/m^3)
NO_2	1-hour	214.1[a]	186	214.1[d]	339	-
	1-hour 98th P	165[b]	96	165[d]	-	188
	Annual	0.08	17	17.08	57	100
SO_2	1-hour	7.8[c]	34	41.8	655	-
	3-hour	3.5[c]	34[e]	37.5	-	1300
	24-hour	0.69	8	8.69	105	-
	Annual	0.005	0.0	0.005	-	-
CO	1-hour	664.0[a]	5039	5703	23,000	40,000
	8-hour	219.1[a]	4352	4571.1	10,000	10,000
PM_{10}	24-hour	3.75[a]	42	45.75	50	150
	Annual	0.036	21	21.036	20	--
$PM_{2.5}$	24-hour	3.75[a]	21.3[b]	25.05	--	35
	Annual	0.036	10.6	10.636	12	15

a. during gas turbine commissioning

b. Three year average of 98th percentile.

c. Shoreline Fumigation Impact

d. Concurrent hourly background included in model runs.

e. Used 1-hour background value for SO_2

TABLE 4-6

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

Pollutant	Averaging Time	Significant Impact Level, μg/m^3	Maximum Modeled Impact for CECP, μg/m^3	Exceed Significant Impact Level?
NO_2	Annual	1	0.08	No
SO_2	3-hour	25	3.5	No
	24-Hour	5	0.69	No
	Annual	1	0.005	No
CO	1-Hour	2000	664.0	No
	8-Hour	500	219.1	No
PM_{10}	24-Hour	5	3.75	No
	Annual	1	0.036	No

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 any Federal or California Ambient Air Quality Standards for NO_2, SO_2, CO and $PM_{2.5}$.

For PM_{10}, 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 24-hour California Ambient Air Quality Standard.

Background concentrations already exceed the annual PM_{10} California standard. Since the background is already in exceedance of the annual standard no additional violations can be due to facility operations. Additionally, the 0.036 $\mu g/m^3$ predicted annual impact is well below PSD Class II significant impact levels shown in Table 4-6. 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 PM_{10} Ambient Air Quality Standards as well.

Appendix D: Proposed Permit Conditions

GENERAL CONDITIONS

1. The equipment authorized to be constructed under this permit is described in Application Nos. APCD2014-APP-003480, APCD2014-APP-003481, APCD2014-APP-003482, APCD2014-APP-003483, APCD2014-APP-003484, APCD2014-APP-003485, APCD2014-APP-003486, APCD2014-APP-003487.

2. The permittee shall cancel all applications for permits and/or retire all permits to operate for all of the equipment authorized to be constructed under this permit on or before the date construction commences for any equipment authorized for construction under Application Numbers APCD2007-APP- 985745, APCD2007-APP-985747, or APCD2007-APP-985748.

3. The permittee shall cancel permit Application Nos. APCD2007-APP-985745, APCD2007-APP-985747, and APCD2007-APP-985748 on or before the date construction commences for any equipment authorized for construction under this permit.

4. 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]

5. 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. 2014-APP-003480, 2014-APP-003481, 2014-APP-003482, 2014-APP-003483, 2014-APP-003484, 2014-APP-003485, 2014-APP-003486, 2014-APP-003487. [Rule 14]

6. 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]

7. 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]

8. 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].

9. 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]

10. 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]

11. 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]

12. The fire pump and emergency diesel engines shall not be operated for maintenance and testing purposes at the same time that any combustion turbine is operating during a commissioning period. [Rule 20.3(d)(2)]

COMBUSTION TURBINE CONDITIONS

DEFINITIONS

13. For purposes of determining compliance with the emission limits of this permit, a shutdown period is the 13 minute period preceding the moment at which fuel flow ceases. [Rule 20.3(d)(1)]

14. 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 25 consecutive minutes. [Rule 20.3(d)(1)]

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

16. 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]

17. For each combustion turbine, the commissioning period is the period of time commencing with the initial startup of that turbine and ending after 213 hours of turbine operation, or the date the permittee 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)]

18. 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

19. The exhaust stack for each combustion turbine shall be at least 90 feet in height above site base elevation, and with an interior exhaust stack diameter of no more than 13.5 feet at the point of release unless it is demonstrated to the District that all requirements of District rules 20.3 and 1200 are satisfied with a different stack configuration. [Rules 20.3(d)(2) and 1200]

20. The combustion turbines shall be fired on Public Utility Commission (PUC) quality natural gas. The permittee 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. Natural gas sulfur content records must be kept with a minimum reporting limit of 0.25 grains sulfur compounds per 100 dscf of natural gas. [Rule 20.3(d)(1)]

21. 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

22. 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]

23. 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]

24. 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 except as specified in the District approved CEMS Protocol. [Rules 69.3, 69.3.1, and 20.3(d)(1)]

25. 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 2.5 parts per million by

volume on a dry basis (ppmvd) corrected to 15% oxygen averaged over a 1-clock-hour period, except during commissioning, startup, and shutdown periods for that turbine. [Rule 20.3(d)(1)]

26. When a combustion turbine is operating, the emission concentration of carbon monoxide (CO) shall not exceed 4.0 ppmvd corrected to 15 % oxygen, averaged over a 1-clock-hour period, except during commissioning, startup, and shutdown periods for that turbine. [Rule 20.3(d)(1)]

27. When a combustion turbine is operating, the volatile organic compound (VOC) concentration, calculated as methane, measured in the exhaust stack, shall not exceed 2.0 ppmvd corrected to 15% oxygen and averaged over a 1-clock-hour period, except during commissioning, startup, and shutdown periods for that turbine. For purposes of determining compliance based on the CEMS, the District approved CO/VOC surrogate relationship and the CO CEMS, data averaged over a 1-clock-hour period shall be used. The CO/VOC surrogate relationship shall be verified and/or modified, if necessary, based on source testing. [Rule 20.3(d)(1)]

28. When a combustion turbine is operating, the ammonia concentration (ammonia slip), shall not exceed 5.0 ppmvd corrected to 15 % oxygen and averaged over a 1-clock-hour period, except during commissioning, startup, and shutdown for that turbine. [Rule 1200]

29. When a combustion turbine is operating, the emission concentration of NOx, calculated as nitrogen dioxide (NO_2), shall not exceed 42 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. [Rule 69.3]

30. When a combustion turbine is operating with post-combustion air pollution control equipment that controls oxides of nitrogen (NO_x) emissions, the emission concentration of NOx, calculated as nitrogen dioxide (NO_2), shall not exceed 13.6 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]

31. 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 22.6 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]

32. For each rolling 4 unit operating hour 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 4 unit operating hour period including the operating-hour and three unit operating-hours immediately preceding. For any unit operating hour where multiple emission standards would apply based on load of the turbine, the applicable standard shall be the higher of the two limits. The hourly emission concentration limit and emission rate limit shall be as follows based on the load of the turbine over the 4unitoperatinghour period:

	Case	**Emission Limit, ppm**	**Emission Limit, lb/MWh**
i.	All 4 hrs at or above 75% Load	15	0.43
ii.	All 4 hrs below 75% Load	96	4.7
iii.	Combination of hrs	(a x 15+b x 96)/4	(a x 0.43+b x 4.7)/4

Where: a = no. unit operating hrs in 4-hr-period with all operation above 75% load and b = 4-a. 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 startup and shutdown 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. For the purposes of this condition, unit operating hour shall have the meaning as defined in 40 CFR 60.4420. [40 CFR Part 60 Subpart KKKK]

33. The emissions of particulate matter less than or equal to 10 microns in diameter (PM_{10}) shall not exceed 5.0 pounds per clock-hour for each combustion turbine. [Rule 20.3(d)(1),(2)]

34. The emissions of particulate matter less than or equal to 10 microns in diameter (PM_{10}) shall not exceed 3.5 pounds per hour per turbine, averaged over all six combustion turbines, calculated as the arithmetic average of the most recent source test for each turbine. [Rule 20.3(d)(1),(2)]

35. 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]

36. 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. [Rule 50]

37. 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, startup and shutdown operations. A 1-clock-hour averaging period for these limits shall apply to CEMS data.

Pollutant	**Emission Limit, lb**

a.	NOx	9.1
b.	CO	8.8
c.	VOC	2.5

[Rule 20.3(d)(2)]

38. 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	14.7
b.	CO	7.4
c.	VOC	2.0

[Rule 20.3(d)(1)]

39. 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	0.6
b.	CO	3.4
c.	VOC	2.4

[Rule 20.3(d)(1)]

40. The oxides of nitrogen (NOx) emissions from each combustion turbine shall not exceed 90 pounds per hour calculated as nitrogen dioxide and measured over each 1-clock-hour period. In addition, the emission concentration of NOx calculated as nitrogen dioxide (NO_2) from each turbine shall not exceed 100 parts per million by volume on a dry basis (ppmvd) calculated over each clock-hour period and corrected to 15% oxygen. These emission limits shall apply during all times a turbine is operating, including, but not limited to, emissions during commissioning, startup and shutdown periods. [Rule 20.3(d)(2)]

41. The carbon monoxide (CO) emissions from each combustion turbine shall not exceed 248 pounds per hour measured over each 1-clock-hour period. In addition, the emission concentration of CO from each turbine shall not exceed 400 parts per million by volume on a dry basis (ppmvd) calculated over each clock-hour period and corrected to 15% oxygen. This emission limit shall apply during all times that a turbine is operating, including, but not limited to emissions during commissioning, startup and shutdown. [Rule 20.3(d)(2)(i)]

42. Total emissions from the equipment authorized to be constructed under this permit 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, beginning with the 12-calendar-month period beginning with the month in which the earliest initial startup among the equipment authorized to be constructed under this permit occurs:

	Pollutant	Emission Limit, tons per year
a.	NOx	84.8
b.	CO	77.8
c.	VOC	24.1
d.	PM_{10}	28.4
e.	SOx	5.6

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating. All calculations performed to show compliance with this limit shall be performed according to a protocol approved in advance by the District. [Rules 20.3(d)(2), 20.3(d)(5), 20.3(d)(8) and 21]

43. Total emissions from each combustion turbine shall not exceed 14.3 tons per year of NOx calculated as nitrogen dioxide and shall not exceed 4.73 tons per year of PM_{10}
For the purposes of this condition emissions shall be calculated on a rolling 12-calendar month basis beginning with the calendar month in which the initial start of the turbines occurs. All calculations performed to show compliance with this limit shall be performed according to a protocol approved in advance by the District.

44. Total emissions from the equipment permitted under APCD2003-PTO-001267, APCD2003-PTO-000791, APCD2003-PTO-000792, APCD2003-PTO-000793, APCD2003-PTO-001770 and APCD2003-PTO-005238 shall not exceed any of the following limits in quantities and according to the schedule based on the number of turbines that have undergone their initial startup as described in the following table:

Number of Turbines Started	NOx (ton/yr)	PM_{10} (ton/yr)
1 gas turbine	No Limit	No Limit
Total of 2 gas turbines	56.4	No Limit
Total of 3 gas turbines	42.2	No Limit
Total of 4 gas turbines	28.1	38.5
Total of 5 gas turbines	13.9	33.8
Total of 6 gas turbines	0.0	29.1

For the purposes of this condition, emissions shall be calculated on a rolling 12-calendar-month basis beginning with the calendar month in which 180 days has passed since the latest initial start from among the indicated number of turbines. All calculations performed to show compliance with this limit shall be performed according to a protocol approved in advance by the District.

45. For each calendar month and each rolling 12-calendar-month period, the Applicant shall maintain records, as applicable, on a calendar monthly basis, of mass emissions during each calendar month and rolling 12-calendar-month period of NOx (calculated as NO_2), CO, VOCs (calculated as methane), PM_{10}, and SOx (calculated as SO_2), in tons, from each emission unit located at this stationary source, 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)(5), 20.3(d)(8) and 21]

46. For each combustion turbine, the number of annual operating hours in each calendar year shall not exceed 2700. For the purposes of this condition, the number of operating hours shall be calculated as the total number of unit operating minutes divided by 60. [Rules 1200, 20.3(d)(2) and 21]

47. For each combustion turbine, the number of startup periods occurring in each calendar year shall not exceed 400. [Rules 1200, 20.3(d)(2) 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, catalyst material, catalyst manufacturer, space velocity and area velocity at full load; 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% and 25% 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 540 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, PM_{10}, 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 PM_{10} 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, PM_{10}, 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, PM_{10}, 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 and quantify toxic emissions:
    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, California H&S Code §41510]

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 earliest initial startup date for any of the 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. Hourly mass emissions of oxides of nitrogen (NOx) calculated as NO_2, in pounds;
    e. Cumulative mass emissions of oxides of nitrogen (NOx) calculated as NO_2 in each startup and shutdown period, in pounds;
    f. Daily mass emissions of oxides of nitrogen (NOx) calculated as NO_2, in pounds;
    g. Calendar monthly mass emissions of oxides of nitrogen (NOx) calculated as NO_2, in pounds;
    h. Rolling 4-unit-operating-hour average concentration of oxides of nitrogen (NOx) corrected to 15% oxygen, in parts per million (ppmvd);
    i. Rolling 4-unit-operating-hour average oxides of nitrogen (NOx) calculated as NO_2 emission rate, in pounds per megawatt-hour (MWh);
    j. Calendar quarter, calendar year, and rolling 12-calendar-month period mass emissions of oxides of nitrogen (NOx), in tons;
    k. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds;
    l. Hourly mass emissions of carbon monoxide (CO), in pounds;
    m. Daily mass emission of carbon monoxide (CO), in pounds;
    n. Calendar monthly mass emission of carbon monoxide (CO), in pounds;
    o. Rolling 12-calendar-month period mass emission of carbon monoxide (CO), in tons;
    p. 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;
    q. Average emission rate in pounds per hour of oxides of nitrogen (NOx) calculated as NO_2 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 Region 9 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. Water injection rate in gallons per minute (gpm) or pounds per hour (lb/hr).

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 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 report to the District. This report shall include, a minimum, the date the commissioning period ended, the startup and shutdown periods, the emissions of NOx and CO during startup and shutdown periods, 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) calculated as NO_2, in pounds;
e. Cumulative mass emissions of oxides of nitrogen (NOx) calculated as NO_2 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;
k. SCR outlet temperature, in degrees Fahrenheit; and
l. Water injection rate in gallons per minute (gpm) or pounds per hour (lb/hr).

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. For each combustion turbine, the Applicant shall submit the following notifications to the District and U. S. EPA, Region 9:
    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]

REPORTING

82. The permittee shall file semiannual reports in accordance with 40 CFR §60.4375. [40 CFR Part 60 Subpart KKKK]

83. Each semiannual report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Each such semiannual compliance report shall be postmarked or delivered no later than January 30 or July 30, whichever date is the first date following the end of the semiannual reporting period. [40 CFR Part 60 Subpart KKKK and Rule 21]

84. All semiannual compliance reports shall be submitted to the District Compliance Division [40 CFR §60.7]

85. Within 120 days of startup of each gas turbine, the owner or operator shall submit an initial notification to the US EPA Region 9 in accordance with 40 CFR 63.6145(c) with the information specified in 40 CFR 63.6145(d). [40 CFR 63 Subpart YYYY]

CONDITIONS FOR EMERGENCY FIRE PUMP ENGINE

86. The exhaust stack for the emergency fire pump engine shall be a minimum of 20 feet in height above grade and a maximum of 0.5 feet in diameter at the point of release and shall not be equipped with a rain cap unless it is of flapper valve design. [Rules 1200, 20.3(d)(2)]

87. The engine shall be EPA certified to the applicable emissions requirements for emergency fire pump engines of 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, based on the power rating of the engine and the engine model year. [40 CFR Part 60 Subpart IIII, and 40 CFR Part 63 Subpart ZZZZ, 17 CCR §93115]

88. This EPA certified engine shall be installed, configured, operated and maintained according to the manufacturer's emission related instructions. The owner or operator may not change any emission related settings unless those changes are permitted by the manufacturer and do not affect the engine's compliance with the emission standards to which it is certified. [40 CFR 60 subpart IIII]

89. The engine shall be operated exclusively during emergencies as defined in Rule 69.4.1, 40 CFR Part 60 Subpart IIII or 17 CCR §93115 as applicable, or for maintenance and testing.

90. Engine operation for maintenance and testing purposes shall not exceed 35 hours per calendar year unless otherwise required by the National Fire Protection Association (NFPA) Section 25. [Rules 69.4.1, 40 CFR Part 60 Subpart IIII, 17 CCR §93115]

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

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

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

94. This engine shall not operate for nonemergency 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. [17 CCR §93115]

95. 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]

96. 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 and 40 CFR Part 60 Subpart IIII]

97. The owner or operator shall keep manuals of recommended maintenance as provided by the engine and control equipment manufacturers for at least the same period of time as the engine to which the records apply is located on site. [Rule 69.4.1 and 40 CFR Part 60 Subpart IIII]

98. The owner or operator of this engine shall maintain records of all maintenance conducted on the engine, including a description of the maintenance and date the maintenance was performed. [Rule 69.4.1 and 40 CFR Part 60 Subpart IIII]

99. The owner or operator shall maintain documentation for all fuel deliveries identifying the fuel as CARB diesel. [Rule 69.4.1, 17 CCR §93115, and 40 CFR Part 60 Subpart IIII]

100. The owner or operator of this engine shall maintain a monthly operating log containing, at a minimum, the following:
    (a) dates and times of engine operation, whether the operation was for compliance with the testing requirements of National Fire Protection Association (NFPA) 25 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, 40 CFR 60 subpart IIII and 17 CCR §93115]

<u>CONDITIONS FOR EMERGENCY ENGINE (GENERATOR)</u>

101. The exhaust stack for the emergency generator engine shall be a minimum of 70 feet in height above grade and a maximum of 0.46 feet in diameter at the point of release and shall not be equipped with a rain cap unless it is of flapper valve design. [Rules 1200, 20.3(d)(2)]

102. The engine shall be EPA certified to the applicable emissions requirements for emergency engines of 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, based on the power rating of the engine and the engine model year. [40 CFR Part 60 Subpart IIII, and 40 CFR Part 63 Subpart ZZZZ, 17 CCR §93115]

103. This EPA certified engine shall be installed, configured, operated and maintained according to the manufacturer's emission related instructions. The owner or operator may not change any emission related settings unless those changes are permitted by the manufacturer and do not affect the engine's compliance with the emission standards to which it is certified. [40 CFR 60 subpart IIII]

104. The engine shall be operated exclusively during emergencies as defined in Rule 69.4.1, 40 CFR Part 60 Subpart IIII or 17 CCR §93115 as applicable, or for maintenance and testing.

105. Engine operation for maintenance and testing purposes shall not exceed 50 hours per calendar year. [Rule 69.4.1, 40 CFR Part 60 Subpart IIII, 17 CCR §93115]

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

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

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

109. This engine shall not operate for nonemergency 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. [17 CCR §93115]

110. 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]

111. 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 and 40 CFR Part 60 Subpart IIII]

112. The owner or operator shall keep manuals of recommended maintenance as provided by the engine and control equipment manufacturers for at least the same period of time as the engine to which the records apply is located on site. [Rule 69.4.1 and 40 CFR Part 60 Subpart IIII]

113. The owner or operator of this engine shall maintain records of all maintenance conducted on the engine, including a description of the maintenance and date the maintenance was performed. [Rule 69.4.1 and 40 CFR Part 60 Subpart IIII]

114. The owner or operator shall maintain documentation for all fuel deliveries identifying the fuel as CARB diesel. [Rule 69.4.1, 17 CCR §93115, and 40 CFR Part 60 Subpart IIII]

115. The owner or operator of this engine shall maintain a monthly operating log containing, at a minimum, the following:
(a) dates and times of engine operation; 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, 40 CFR 60 subpart IIII and 17 CCR §93115]

116. Within 120 days of startup of this engine, the owner or operator shall submit a notification to the District indicating that this source is a major source of HAP. [40 CFR 63 Subpart ZZZZ]