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REVISED FINAL
DETERMINATION OF COMPLIANCE

CARLSBAD ENERGY CENTER

SAN DIEGO AIR POLLUTION CONTROL DISTRICT
April 17, 2015

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

DISTRICT REVIEW INFORMATION

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App. 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
Site ID Number:	1982-SITE-00195
Fee Schedule:	6 x 20F, 2 x 34H
BEC:	TBD

APPLICATION INFORMATION

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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
CAISO – California Independent System Operator
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
OEHHA – Office of Environmental Health Hazard Assessment (California)
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
NO_2 – Nitrogen dioxide
O_2 – Oxygen gas
PM – Particulate matter
PM_{10}, $PM_{2.5}$ – PM with aerodynamic diameter $\leq$ 10 microns or 2.5 microns, respectively
S – Sulfur
SF_6 – Sulfur hexafluoride
SOx – Sulfur oxides
SO_2 – Sulfur dioxide
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-985747, and APCD2007-APP-985748, 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 LMS100-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 the 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 PDOC/FDOC review is functionally equivalent to an Authority to Construct review, and FDOC conditions serve as the conditions of the Authority to Construct upon approval of the license application by the CEC.

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 105.3 MW (net) natural-gas-fired simple-cycle General Electric LMS100-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; and with the 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 105.3 MW (net) natural–gas-fired simple-cycle General Electric LMS100-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; and with the 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 105.3 MW (net) natural-gas-fired simple-cycle General Electric LMS100-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; and with the 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 105.3 MW (net) natural-gas-fired simple-cycle General Electric LMS100-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; and with the 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 105.3 MW (net) natural-gas-fired simple-cycle General Electric LMS100-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; and with the 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 105.3 MW (net) natural-gas-fired simple-cycle General Electric LMS100-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; and with the 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; and an oxidation catalyst; and a SCR system. Each combustion turbine will be a General Electric, model LMS100-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 a multistage compressor section of the turbine where the pressure is further increased. Unlike typical simple-cycle turbines, air is removed from an intermediate stage of the compression process and passed through an external cooling system using ambient air, which improves the turbine efficiency and lowers the exhaust temperature. The air then passes to the combustion section where natural gas fuel is introduced and combusted, resulting in rapid temperature and pressure increases 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, CO, 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.

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 VOCs 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 and air quality impacts. 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 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 new equipment on an hourly and annual basis based on standard emission factors. 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

$$EF = \frac{C}{10^6} * \frac{MW}{(385)} * F * \frac{(20.9)}{(20.9-\%O_2)}$$

Where:
EF = Emission Factor (lb/MMBtu);
C = Pollutant 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 at 68° F and one atmosphere);
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 a specified O_2 content; and
$\%O_2$ = Stack oxygen content (%) at which the pollutant concentration is specified;

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

Equation 2: Emission Calculations

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

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 , based on a standard temperature of 60° F and one atmosphere, 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 percent, 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 Weight 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)

Year	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, EPS 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. Also shown is the five year average emissions for 2009-2013.

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

Table 2: 2-Year and 5-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
5 Year	**44.23**	**140.46**	**22.87**	**31.65**	**2.98**	**6.41**

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 new gas turbines 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, Emissions 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 permit conditions that limit NOx to 2.5 ppmvd at 15% O_2, CO to 4.0 ppmvd at 15% O_2, VOC

[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.

limited to 2.0 ppmvd at 15% O_2, and ammonia (NH_3) slip to 5.0 ppmvd at 15% O_2. Equations 1 and 2 above were used to calculate emissions in pounds per hour from these values. PM_{10} and $PM_{2.5}$ emissions are assumed to be the equal, and reflect permit conditions that limit maximum emissions to 5.0 lb/hr for any one turbine. SO_2 short term emissions (24 hours or less) are 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 calculated 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 maximum 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 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.

In comments on the PDOC, the Applicant requested that the startup and shutdown limit be increased for the commissioning year since many activities that occur during commissioning may also be considered startups. The District agrees there is the potential for a large number of startups during commissioning and finds that allowing a limited number of additional startups during commissioning will not haveany significant air quality impacts. Consequently, an additional 350 startups per turbine are allowed by the permit during the commissioning period for each turbine as well as the 400 startups per year allowed for normal operations. This does not affect annual PTE of any criteria pollutants because annual emissions of each are limited by annual emission limits that are not affected. In the case of CO, there is a higher limit for emissions during commissioning, but this is not based on the increased number of startups. The only potential effects, if any, relate to the AQIA and HRA. Those potential effects are discussed in the relevant sections.

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 all 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 one hour 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).

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

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

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
Turbine Commissioning*		24.27					
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	102.1	24.06	5.59	28.35	28.35	54.29

*This represents an additional allowance for CO during commissioning years as is discussed below.

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 of the EPS. Based on review of emissions data and other supporting information, the District determined that no two-year period or any two one-year periods were representative of operation over the five year period. Because a representative period could not be found between these two options, the District determined that an average of all five years of emission data (2009 through 2013) is most representative of facility operation and, therefore, was used for calculating the net emission increase (or decrease) as discussed in detail in Section 6. 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	102.1	24.06	5.59	28.35	28.35	54.29
Post-project PTE with NOx limit	84.18	102.1	24.06	5.59	28.35	28.35	54.29
Baseline emissions/Actual emission reductions	44.23	140.46	22.87	2.98	31.65	31.65	6.41
Net increase	**39.95**	**--38.36**	**1.19**	**2.61**	**-3.30**	**-3.30**	**47.88**

*In years including commissioning only. Permit conditions will limit annual CO PTE to no more than 77.83 ton/yr in years without commissioning.

Based on this calculation the project will result in an emission decrease for CO, and PM_{10}/$PM_{2.5}$. It will result in an increase of NOx, VOC, SOx 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 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 (about 0.025 pounds per year). 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).

In comments on the PDOC, the Applicant pointed out that annual emission limit of 77.83 tons per year did not account for the elevated levels of CO emissions during commissioning operations (as shown in table 5.1B-14 of the application submittal) which may reach 102.1 tons, exceeding the normal year PTE by up to 24.27 ton/yr. Rather than having an annual limit of 102.1 tons per year during years in which commissioning operations occur, permit conditions limit CO emissions in each year proportionally based on the number of turbines commissioned during the year This way the total additional CO emissions from commissioning are limited to a maximum of 102.1 tons CO in any year, not to exceed a total 24.7 additional tons CO for commissioning overall. The turbines are expected to be able to comply with this limit. The project is treated as having a post-project PTE for CO emissions of 102.1 ton/yr when evaluating compliance with District Rules and Regulations.

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 procedures previously described assuming an ammonia slip of 5.0 ppmvd at 15% O_2, which is the

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

maximum allowed in the 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 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. During any commissioning year, the estimated CO emissions might be as high as 102 ton/yr and, therefore, are reflected in the PTE for CO when determining rule applicability.

In comments on the PDOC, the Applicant requested that any startups and shutdowns occurring during commissioning not count towards the annual limit of 400 startups. The District evaluated this request and concluded that an additional 350 startups per turbine could be allowed during commissioning for each turbine and still comply with the applicable District rules. For criteria pollutants, annual emissions during commissioning (except CO, see above) are limited to same extent as a normal operating year, so no change is expected to potential emissions, and the maximum hourly emissions and worst-case release parameters (exit velocity and temperature) are not affected. The potential impact on toxic emissions, if any, is discussed under the Rule 1200 section.

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.

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

Table 12: Comparison of Emissions for Licensed and Amended CECP (not including commissioning CO)

	NOx	CO	VOC	SOx	(PM_{10})	($PM_{2.5}$)
Licensed	72.11	217.3	20.05	5.6	39	39
Amended	84.18	102.1	24.1	5.6	28.4	28.4
Increase	12.07	-115.2	4.0	0	-10.6	-10.6

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. Table 13 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	933,318	846,692
Engines	28	26
Compressors	60	55
Breakers	136	123
Total	933,542	846,896
Existing baseline	492,666	447,878
Net increase	440,876	399,019

6.0 Rules Analysis

6.1 District PSD and NSR Rules

Rule 20.1(c)(16): Contemporaneous Emission Increase and 20.1(d)(2) Pre-project Actual (Baseline) Emissions

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

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

project commences operation and the calendar year the project is expected to commence operation, for a total of five 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 EPS peaking turbine with District Permit No. APCD2003-PTO-001267 and the five existing utility boilers, EPS Units 1, 2, 3, 4, and 5 with 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 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 increases listed in Table 11 in Section 5. Furthermore, 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.

Pre-project actual emissions for the project were calculated in accordance with Rule 20.1(d)(2) which provides for three tiers for determining the appropriate period for calculating actual pre-project emissions. The top tier is "the most representative two consecutive years within the five years preceding the receipt date of an application, as determined by the Air Pollution Control Officer" [Rule 20.1(d)(2) (A)]. If a representative two-consecutive year period cannot be established, the second tier is "For emission units which have not been operated for a consecutive two year period which is representative of actual operations… the calculation of actual emissions shall be based on the average of any two one-year operating periods determined by the Air Pollution Control Officer to be representative within that five-year period…" [Rule 20.1(d)(2) (B)]. Finally, if no two non-consecutive years can be found to be representative, the third tier is "…the calculation of actual emissions shall be based on the average of the total operational time period within that five-year period" [Rule 20.1(d)(2) (B)].

The applications were submitted on May 5, 2014, so the years of interest are calendar years 2009 through2013. The Applicant initially proposed to use the two-year average of 2011 and 2012 because this represented the highest level of emissions for most pollutants according to their calculations. The District disagreed with this approach because the selection of which years to use should be based on which period is most representative of operation, not necessarily based on the highest level of emissions and the fact that the EPS appeared to be operating more like a peaking power plant in the five-year period. Operating as a peaking power plant results in more variability in operating levels and emissions since peaking power plants need to respond to the peak loads on the electrical grid resulting from the differential between the power demand and the power supplied by available base load plants. Because the electrical needs addressed by peaking power plants are the differential in two large numbers (demand and base load supply) the number and magnitude of the electrical needs that must be satisfied by peaking power plants is highly variable year-to-year as a result of variability in such factors as weather, electrical generating resources, dispatch criteria, and the state of the transmission system. Peaking power plants may need to operate both to satisfy both electrical energy demand and address grid reliability needs. Unlike simple-cycle turbine power plants, the EPS requires significant amounts of time to come on line (overnight from a cold start). Hence, if its operations are considered to be needed to provide power the next day the EPS often operates at a low load overnight so as to be available to respond rapidly to peak power demands. This can accentuate the amount of emissions in long periods when its power is needed to respond to peak demands.

In the PDOC, the District initially considered 2012 and 2013 to be the most representative two-consecutive-year period in the five-year period because those years represented operation after the unexpected loss and ultimately permanent closure of San Onofre Nuclear Generating Station,(SONGS) and best reflected current normal of operations. The loss of 2300 MW of base load electrical supply, a significant portion of which supplied electrical demand in San Diego county and also provided other important factors needed for grid reliability, would be expected to permanently increase the likely extent and magnitude of peak electrical demands or electrical grid reliability within the San Diego Gas & Electric (SDG&E) local reliability area and sub-areas that could not be satisfied by base load generation. Although 2012 was significantly higher than 2013, this could be the result in the natural variability in peak loads exacerbated by the loss of SONGS.

The District received a number of comments on the PDOC relating to the selection of the baseline both in opposition and in support of the chosen baseline period. Generally, comments received in opposition to the selection of the baseline period indicated that the selected two years were inappropriate because the emissions from the facility in 2012 were much higher than other years and in particular much higher than 2013. This was considered inappropriate by the commenters because it favored the Applicant by causing the project to not be subject to requirements, including NOx offsets and District PSD review, the applicability of which are based on the net emission increase from the project above the pre-project actual emissions for each pollutant. The commenters instead requested that the District use the average emissions for the entire five-year period to determine pre-project actual emissions. Commenters also noted that a five-year period was used for evaluation of the licensed CECP, so a five-year average is also appropriate to maintain consistency. Comments in support of the chosen baseline were received from the Applicant, which agreed that the chosen years were most representative for the same reasons selected by the District, and noting that while the emissions were high in 2012, they represent how the facility operated and could operate in the future.

In considering these comments, the District sought additional information to determine whether operation in 2012 relative to 2013 was the result of natural variability in peak electrical demand or, at least partially, the result of other factors. The District noted that while emissions were higher in 2012 than in other years between 2009 and 2013, NOx emissions during 2012 are only 1.88 standard deviations higher than the average (assuming a normal distribution), which, while relatively high, would not necessarily be considered a statistical outlier – so the level of emissions by itself does not support that 2012 was not representative of normal operation in the post-SONGS period. However, after consultation with the California Independent System Operator (CAISO), the District determined that permanent changes in the transmission system and grid operations between 2012 and 2013 likely accounted for much of the decrease in operations in 2013 relative to 2012.

CAISO noted that much of the operation of the EPS is due to CAISO dispatching it to maintain grid reliability within the SDG&E local reliability area and sub-areas. One component of grid reliability used by CAISO is known as the "minimum online commitment" or MOC. MOC refers to the minimum amount of resources (generating plants) that must be operating at any time to ensure that in a grid emergency, resources are available to pick up the electrical demand load and maintain grid reliability. CAISO determined that much of the operation of the existing EPS units in 2012 and 2013 was likely to meet MOC requirements (the MOC requirement was implemented as part of CAISO's dispatch protocol for the SDG&E local reliability area and sub-areas in 2010). However, the completion of the Sunrise Powerlink and the conversion of a portion of the Huntington Beach power plant in the Los Angeles area to a synchronous condenser in 2013 tended to lower the MOC requirements in San Diego, which CAISO considers to have contributed to the reduction in the plant operating level in 2013 relative to 2012. Nevertheless, and EPS operations in 2012 did represent a normal response to the conditions that existed in 2012. In addition, the loss of SONGS in early 2012 did fundamentally change the EPS operational environment from that which existed in the 2009–2011 period.

The District also notes that even in 2009–2011 there is a high variability in generation and emissions. For example NOx emissions are about twice as high in 2009 as 2010, the lowest year in the five-year period, and about 50% higher in 2011 than in 2010 (see Table 1). Similarly, fuel use as an indicator of operating levels followed a similar pattern (see Table A-7).

Considering the fundamental changes in the transmission system, dispatch protocols, and generation resources combined with the high level of annual variability in operating levels, the District finds that neither a two-consecutive-year period nor a two-nonconsecutive-year period are representative of operation over the 5-year period. For this reason, the District finds that the third available tier in Rule 20.1(d)(2) (B), the average of the facility's emissions over the 5-year period to be most representative. In this case, this is a five-year average of the facility's operation for 2009-2013 as presented in the calculations section. This five-year average was considered the pre-project actual emissions for each pollutant and used for determining actual emission reductions.

Rule 20.1(c)(35), 20.1(c)(33): Major Stationary Source and Major Modification

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 (and potentially CO during commissioning years). 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. 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 84.18 tons of NOx per year This ensures that the contemporaneous emission increase of NOx does not exceed 39.95 tons per year which means the project is considered a major modification. 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 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. The potential to emit lead is estimated to be only 1.25×10^{-5} tons/year which is much below the standard and, therefore, no limits are necessary (see HRA in Appendix B).

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 will not be in effect absent EPA approval. This analysis is, therefore, directed toward determining applicability and requirements for District PSD and not directed toward determining applicability and requirements of federal PSD.

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 and will be under the 250 ton/yr limit for each pollutant. However, since it is expected that the project will begin construction (and likely operation) before the EPS boilers are permanently retired, the facility is considered a PSD stationary source. Additionally, the District notes that PSD requirements only apply to projects that result in a PSD modification at an existing PSD stationary source, which does not apply to this project as described below.

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 and, therefore, not subject to District PSD review.

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, assuming one hour per day of operation for maintenance and testing according to standard District policy, 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 does result in a major modification for NOx, so LAER is required for NOx. The primary differences between District BACT requirements and LAER requirements are that LAER does not consider the cost of the emission controls. The BACT analysis in this evaluation does not consider cost, so compliance with BACT emission limitations as discussed below also ensures compliance with LAER requirements as well. Although not required, the analysis does consider alternative technologies.

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.

Normal/Steady State 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 combined-cycle units.

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 are GE LM6000 turbines and were permitted at 2.5 ppmvd at 15% O_2 averaged over one-hour. The District has also issued an FDOC for the Pio Pico Energy center, which would include three GE LMS100 PA turbines similar to those proposed for this project, that are 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.

Review of ARB/EPA RACT/BACT/LAER 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. South Coast Air Quality Management District (SCAQMD) has also issued FDOCs for the CPV Sentinel plant[9], Walnut Creek Energy Park[10] and Panoche Energy Center[11], all of which are now operating utilizing similar GE LMS100-PA combustion turbines and have emission limits of 2.5 ppmvd NOx at 15% O_2 averaged over one hour. For combined-cycle turbines, the EPA database listed 2.0 ppmvd at 15% O_2 as the lowest emission rate (Marshalltown Generating Station, two approximately 300 MW Siemens SGT6-5000F gas turbines).

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 at 15% O_2 has been

[9] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=07-AFC-03.
[10] http://www.energy.ca.gov/sitingcases/walnutcreek/
[11] http://www.energy.ca.gov/sitingcases/panoche/

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) and has only been demonstrated on smaller cogeneration systems such as installed on turbines permitted by the District at UC San Diego.

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 and LAER for this air contaminant for the combustion turbines during normal steady state operation. This limit is the lowest achieved in practice for the use of SCR with a simple-cycle unit. 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.

VOC:

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 emission limit achieved in practice.

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 at 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 at 15% O_2 is BACT for VOC. Initial and subsequent source testing will be used to determine compliance with these limits.

The District reviewed additional information that a commenter believed indicated that a VOC emission level of 1.0 ppmvd at 15% O_2 is achieved in practice for simple-cycle turbines. The information consisted of 2012–2014 source test summaries for four GE LM6000 PC-Sprint turbines. The turbines use water injection and an SCR for NOx control, an oxidation catalyst for VOC control and are rated at about 50 MW of electrical output. The VOC limit is 0.612 pounds of VOC, which is equivalent to about 1.0 ppmvd at full load. The test method used to determine compliance was EPA Method 18 using gas chromatography with a flame ionization detector (FID) and with the sample concentrated per EPA Method TO-12.

Because there are size and functional differences between the LMS100 and LM6000 turbines—for example, continuous external cooling of the compression air for the LMS100 (the Sprint turbine's compression air can be cooled by injecting water although there was no evidence in the summaries that this was done or not done during the VOC source tests)—that could potentially affect the VOC emissions, the District analyzed available data for emissions from LMS100 turbines, the model of turbine proposed in the application. Additionally, as shown in Appendix F, the District found some LM6000 Sprint turbines in San Diego County with emissions above 1 ppm VOC.

The District notes that variation in source test methods and reporting procedures complicates comparison of VOC results from different sources. Additionally, many of the tests were not witnessed by staff of the districts where the tests were conducted, which is contrary to standard SDAPCD procedures. The tests analyzed by the District included data measured using variations of EPA methods 18, TO-12, and 25 such as SCAQMD using a modified method 25.3. Emission data measured using method 18 with an FID is known be insensitive to formaldehyde in the results, and formaldehyde may make up a sizeable portion of VOC emissions from gas turbines. Emission data measured using method 25 is known to potentially exclude ethylene and acetylene which are also expected to exist in VOC emissions from gas turbines. Depending on the specific variation of method 25 used, it may be inaccurate for measuring low concentrations of VOC (although SCAQMD modified method 25.3 is specifically designed to measure low VOC concentrations but likely excludes ethylene and acetylene). Additionally, different districts and testing companies have different procedures for presenting VOC data that is below the detection limit. A significant portion of the VOC data examined included data that was measured below the detection limits. This meant that sources using less conservative reporting procedures may report VOC values below 1.0 ppm or even 0 ppm while other sources using more conservative reporting procedures might report the same data as above 1.0 ppm. The District typically follows more conservative reporting procedures to ensure that emission estimates do not omit any VOC emissions because they are below detection limits.

The District also examined the initial source test results for LMS100 turbines installed for the CPV Sentinel and Walnut Creek Energy Park in 2013 (there have not been any further tests to date for these units) which are located in the South Coast AQMD and permitted with emission limits of 2.0 ppm VOC corrected to 15% oxygen. Both plants were tested using the same methodology (SCAQMD Method 25.3). These tests found that Turbines Nos. 1, 3 and 8 at CPV Sentinel had individual subtests that exceeded 1 ppm VOC, reaching up to 1.67 ppm VOC corrected to 15% oxygen for Turbine No. 1. Furthermore, the three-subtest average for Turbine No. 1 was 1.25 ppm VOC corrected to 15% oxygen. Table 14 below shows results of a statistical analysis of the VOC data (see Appendix Table A-16) showing that the random variation in the measured VOC concentrations (same turbine model, test methods, test procedure, testing company and approximate testing timeframe) would be expected to exceed 1.0 ppm VOC up to 8% of the time. When operating at 50% load, an exceedance of the limit is predicted over 10% of the time assuming a normal distribution. Violations are also predicted if a log-normal distribution is assumed with an 8% probability of exceeding at 50% load and 4% probability at 100% load. In addition, since no turbine has been tested more than once (the initial source test) it is not clear how VOC exhaust concentrations will behave over time. A full table of VOC results is included in appendix F. Also included in appendix F are VOC test results from GE LM6000 Sprint turbines in San Diego County which also showed some readings above 1 ppm.

Table 14: Summary of VOC emission data for CPV Sentinel and Walnut Creek LMS100 Turbines (normal)

Load	Walnut Creek Average (ppm VOC at 15% O_2)	Sentinel Average (ppm VOC at 15% O_2)	Combined Average (ppm VOC at 15% O_2)	Combined Standard Deviation (ppm VOC at 15% O_2)	Predicted 1 ppm % Exceedance
100%	0.610	0.678	0.652	0.326	7%
75%	0.564	0.683	0.637	0.294	5%
50%	0.642	0.820	0.752	0.346	12%
Overall	0.605	0.727	0.680	0.318	8%

The District also notes that SCAQMD Method 25.3 likely does not measure ethylene and acetylene concentrations, which are among the more likely hydrocarbon VOC emissions from gas turbines and may underestimate VOC emissions in that regard.

NRG has no control over the quality of gas carried through utility gas lines and the oxidation catalyst is a passive system that is expected to operate as intended any time the temperature is sufficient for the oxidation reaction to proceed so there are no feasible process control improvements that would reduce emissions. The only other technique the District considers feasible to reduce VOC emissions further is the installation of additional oxidation catalyst volume. However, inspection of the engineering evaluations/FDOCs issued by SCAQMD for each of these projects (available under the CEC docket for each applicable project) shows that the CPV Sentinel turbines were installed with more than double the catalyst volume of the Walnut Creek turbines (150 cubic feet vs. 72 cubic feet) yet had higher emissions, so it is not expected that addition of catalyst would achieve any emission reductions. There are, therefore, no additional techniques available to reduce emissions, and the limit proposed in the PDOC of 2.0 ppm VOC as methane corrected to 15% oxygen averaged over one hour is considered BACT.

Based on this analysis the District finds that 1.0 ppm VOC corrected to 15% oxygen is not achieved in practice for this class of simple-cycle turbines. In addition, the District has revised the PDOC conditions to require that formaldehyde be included in determination of compliance with VOC limits in this permit. EPA Method 18 using a FID can detect ethylene and acetylene. However, the FID is insensitive to formaldehyde. For this reason, the District is including separate testing methodology for formaldehyde in the permit when determining VOC concentrations.

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 LMS100 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[12]. Based on comments received, the District conducted a separate analysis of this and some additional PM test data and reached the same conclusion – an hourly emission limit for a single turbine of 3.5 lb/hr is not achieved in practice, and is predicted to be exceeded over 15% of the time for some facilities as shown in

[12] 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.

Table 15 (assuming a log-normal distribution, 11% of the time). Based on this information, the District concludes 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.

Table 15: Summary of PM emission data for Panoche Energy Center LMS100 Turbines (normal)

Mean (lb/hr)	SD (lb/hr)	Predicted 3.5 lb/hr % Exceedance	Max (lb/hr)
2.70	1.64	16%	11.16

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 (S) limits of 0.75 grains per 100 scf (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 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[13] 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 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

[13] http://www.sdge.com/rates-regulations/current-and-effective-tariffs/gas-tariff-book-rules

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 LMS100-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[14].

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.

For NOx, in addition to the above limit, the 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 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, and LAER for NOx, 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. When using CEMS data, VOC emission rates are determined using CO as a surrogate. All startup and shutdown emissions must also be

[14] 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

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 permit conditions, except that an additional 350 startups are allowed during each turbine's commissioning period which do not count towards the annual limit. The District notes that CO emissions are not subject to BACT requirements, but the CO emission limitation is needed to ensure emissions do not exceed the levels assumed for AQIA purposes.

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, and LAER for NOx, 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 (excluding commissioning emissions). Permit conditions require compliance with a 4 ppmvd CO at 15% O_2 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. Because the actual number of startups required is speculative, the plant must be designed to achieve the fastest starts and ramping with the maximum amount of operating flexibility in order for the plant to be able to respond to grid needs in extreme cases – which favors simple cycle turbines over combined cycle. Additionally, the turbine heat rate of a combined cycle plant over a simple cycle plant (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. This also doesn't take into account that, because combined cycle plants are more difficult to start and load into the grid and more difficult to shutdown and disconnect than alternative technologies (e.g. photovoltaic), over-installing combined cycle generating plants may have the added disadvantage of increasing renewable curtailment.

Alternative fuels were eliminated because there are no available lower emitting fuels for turbines. To address energy efficiency, the Applicant stated that these LMS100 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 LMS100 turbines as the most efficient[15]. 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 LMS100 turbines for CPV Sentinel(7,686-7,998 at full load depending on ambient conditions)[14]. Turbines utilizing dry low NOx technology also have slightly better heat rates, but the reduced turndown ability makes them less favorable for this project which requires flexibility. 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 LMS100 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 needs for load following and 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. However, this technology is not currently achieved in practice, so is not required to be considered in the BACT analysis.

Finally, based on comments received on the PDOC, the District performed some additional analysis looking at battery storage technologies and found that they are not required for BACT. Battery storage on a large enough scale to replace one of the LMS100s power for a reasonable time period has not been proven achieved in practice; is not an "emission control device, emission limitation or control technique", and is also not required by any SIP approved by the federal EPA. It is a process modification. However, for a process modification to be considered BACT, it must be "determined by the Air Pollution Control Officer on a case-by-case basis to be technologically feasible and cost-effective," and the District has not made this determination regarding battery storage. The District has not made this determination for battery storage for a combination of reasons, including that the technology is unproven and that actual emissions from the both the site and the grid could increase from the installation of battery storage at this location.

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

Sodium-sulfur (Na-S) and flow batteries, which are often used for large scale electrical storage, that are currently available (for example the Eos battery system[16]) have a maximum efficiency of approximately 50-80% under ideal conditions which means that they require between 1.25 and 2 times the energy to charge as they provide on discharge. Unless a high percentage of the electricity used to charge the batteries was produced by zero emission sources, there would be a minimal benefit to overall grid emissions and in fact battery use could cause an increase in emissions if the percentage of renewable energy is less than the energy losses from charging and discharging the battery – with the worst case being if the proposed amended CECP turbines were operated to charge the batteries. Conventional batteries, such as lead acid and lithium-ion batteries, may have higher efficiencies, about 90%, which would still require about 1.1 times the energy to charges than was provided on discharge.

Although the District does not consider combined-cycle turbines a viable alternative for other reasons, another configuration would be to use the batteries with a combined-cycle plant to provide peaking power as the combined-cycle units are started and come to full load. The District estimates that no operational battery systems would meet the necessary power and energy requirements for this configuration. And, in this case, emissions from the turbines would likely increase rather than decrease because the batteries would only run as the plant is starting and the ability to start faster would cause the facility to run more than it would have without battery storage capability.

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 and reviewed by the District, the District 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 or otherwise do not meet BACT requirements.

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 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

[16] http://reneweconomy.com.au/2015/eos-energy-to-offer-mw-scale-battery-storage-system-at-160kwh-2016

ensured through 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 operational modes resulted in the highest impacts[17]. These modes 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 from simultaneous periods as the meteorological data used for themodeling 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 presented in Table 6 of Section 5.
- For commissioning, the District modeled two separate modes 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 assumed 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 Section 20.3(d)(2). Permit conditions contain limits on mass emissions of each applicable pollutant for various operating modes 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.

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

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

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.

The increase CO emissions during the commissioning year(s) does not affect the conclusions of the AQIA performed for the PDOC. The AQIA conducted found that commissioning (idle operation) resulted in the highest 1-hour and 8-hour impacts for CO compared to other operating scenarios. There is no annual ambient air quality standard for CO. Allowing additional CO emissions during commissioning affects only the annual rate of emissions and not the 8-hour and 1-hour impacts, so there is no effect of the added emissions on compliance with the CO ambient air quality standards.

Also, allowing 350 additional startups during the commissioning period for each turbine in addition to the 400 allowed for normal operation in the rest of the years also does not affect the AQIA conclusions because annual emissions do not change (except for CO as discussed above) and the sync idle commissioning operational mode results in higher short-term impacts than startups and shutdowns for all modeled pollutants.

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 permit 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 was published in the San Diego Daily Transcript and San Diego Union Tribune and mailed to the EPA, ARB, neighboring air districts, and affected states on December 17, 2014. The comment period commenced on December 17, 2014 andclosed on January 16, 2015. On January 16, 2015, the comment period was extended to February 2, 2015.

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. As previously discussed, this project is a major modification for NOx with an emission increase of 39.95 tons NOx. Emission increases must be offset at a ratio of 1.2:1.0, resulting in a requirement for 47.94 tons of Class A NOx credits to be provided for the project. Emission reduction credits of VOC may also be used to offset NOx at a ratio of two tons of VOC reduction for each ton of NOx reduction. Permit conditions specify the requirement that sufficient credits be surrendered to the District prior to beginning construction on the project. Appendix E lists emission reduction credits proposed to be used, which are in sufficient quantity to meet the offset requirements.

Rule 20.3(e)(1): Compliance Certification

This project is subject to LAER and offset requirements, and, therefore, a compliance certification is required, prior to issuance of the CEC final decision certifying that all major sources operated by the applicant in the state are in compliance with all applicable emissions limitations and standards under the federal Clean Air Act. The Applicant is an indirect wholly owned subsidiary of NRG Energy, Inc., which also operates the Encina Power Station. The Applicant submitted a compliance certification on March 19, 2015 indicating compliance at all applicable major sources and so satisfies this requirement.

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

This project is subject to LAER and offset requirements, and, therefore, an alternative siting and alternatives analysis is required. The Applicant has provided an analysis of various alternatives to the project through the CEC process. This analysis included a No Project alternative, alternative sites, and alternative technologies. Since all of San Diego County is currently classified as non-attainment for ozone, an alternative location within San Diego would not avoid the project being located in a non-attainment area. Regarding alternative sizes of equipment, the BACT/LAER review conducted by the District included review of simple-cycle turbines of different sizes and did not find that any combination of turbines of different sizes than those proposed would result in lower emission levels for approximately the same total project power.

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 issues 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. The District has issued a PDOC and FDOC in accordance with these requirements.

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 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. 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 SO_2 emission estimates are basedon fuel gas flow rate and sulfur content, the SO_2 concentration can be estimated assuming the sulfur contents, heat contents and F-factors described in Section 5:

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

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:

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

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. 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. Therefore 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 permit conditions. The 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:

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

Where:
LHV/HHV = 1/1.11;
MRTE[18] = 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 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, implements federal RACT, and is approved into the SIP. This source is a major stationary source of NOx, 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 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. Both engines proposed for this project are certified with NOx emissions below this level[19]. 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

[18] 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 an efficiency of 41.85%.
[19] See attachment 7 included with the 6/27/2014 incomplete letter response

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 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 expected 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.

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 individual resident (MEIR) 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 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 commissioning impacts were accounted for in a separate acute analysis. 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 permit conditions. No additional analysis is, therefore, required. The Applicant subsequently requested to clarify that startups occurring during commissioning should not be counted against the 400 startup annual limit. Permit conditions will allow an additional 350 startups and shutdowns per turbine during commissioning. The duration of commissioning is not increasing, and since the HRA performed by the District assumes that each commissioning hour results in the highest level of emissions (i.e. 213 hours of idle operation/turbine) and VOC/Toxic emissions are higher during an hour of idle operation than during a startup and shutdown hour, allowing an additional 350 startups and shutdowns per turbine only during commissioning does not result in an increase in toxic emissions or increased health risk.

The District also examined the effects of newly proposed HRA procedures issued by OEHHA that were adopted on 03/06/2015. The new procedures result in an increase in cancer risk. Using a beta version of the updated software, the District calculated that the increase in cancer risk due to the project increases to 0.24 in one million at the MEIR, which is a 3.7 times increase over the original prediction and is still below the standard of one in one million. The new procedures have no effect on the cancer risk assessment for the MEIW.

A final consideration is that Rule 1200 is based on increases of emissions due to a project. Since, as proposed by the Applicant, the 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 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[19]. Permit conditions require that an EPA certified engine be installed which ensures the engine meets these certification requirements and 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[19] 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. Permit conditions require that an EPA certified engine be installed which ensures the engine meets these certification requirements. 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 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 permit conditions require 5 years onsite for all records). All of these requirements are specified in the 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[20]. Because these turbines are expected to startup at a time that this facility is a major source of HAP, 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, 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

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

[20] 69 FR 51184. http://www.epa.gov/ttn/atw/turbine/fr18au04.pdf.

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 15: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 permit conditions. Compliance with all 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 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[21] indicating sulfur content below this level, no monitoring is required under this section provided fuel is supplied by SDG&E. However, other 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 permit conditions.

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

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

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 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. 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 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, 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 permit conditions. No notifications or reports are required.

The 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 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 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 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 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 Final Determination of Compliance, this equipment is expected to operate in compliance with all Rules and Regulations of the San Diego County Air Pollution Control District. (See appendix D for the proposed conditions)

Signed By ______________________ 4/17/15
Project Engineer Date

Signed By ______________________ 4/17/15
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

<u>Notes:</u>
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

<u>Notes</u>:

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.

FOR INFORMATIONAL PURPOSES ONLY

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

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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

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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).*

Table A-16: VOC Emission Data from CPV Sentinel and Walnut Creek Energy LMS100 Turbines

Site	Unit	Catalyst Vol. (ft^3)	Stack Temp (F)	VOC (ppm 15% O_2)	Load	ND?*
			747	0.69	100%	
			761	0.62	75%	
	1		784	0.73	50%	
			739	0.8	100%	
			762	0.56	75%	
	2		786	0.7	50%	
			737	0.53	100%	ND
			761	0.54	75%	ND
	3		787	0.6	50%	ND
			754	0.52	100%	ND
			781	0.56	75%	ND
	4		818	0.57	50%	ND
			763	0.51	100%	ND
			790	0.54	75%	ND
Walnut Creek Energy	5	72	807	0.61	50%	ND
			766	1.67	100%	
			768	0.61	75%	
	1		771	1.48	50%	
			781	0.75	100%	
			785	0.55	75%	
	2		796	0.68	50%	
			780	0.52	100%	
			768	0.52	75%	
	3		782	1.55	50%	
			786	0.58	100%	
			752	0.56	75%	
	4		769	0.55	50%	
			736	0.51	100%	ND
			733	0.51	75%	ND
	5		776	0.59	50%	ND
			756	0.5	100%	ND
			759	0.51	75%	ND
	6		796	0.55	50%	ND
			767	0.47	100%	ND
			766	0.59	75%	ND
	7		791	0.67	50%	ND
			805	0.42	100%	ND
			796	1.61	75%	ND
CPV Sentinel	8	150	819	0.49	50%	ND

***Denotes a value based on a non-detection**

All data from source test reports prepared by Delta Air Quality Services, Inc. and submitted to SCAQMD on behalf of the subject facilities for the purposes of initial compliance testing in 2013.

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:	March 24, 2015

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 organic 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

Note: For comparison of the existing cancer risk to the updated Air Toxics Hot Spots Program Guidance Manual dated February 2015, cancer risk at the maximum exposed individual resident (MEIR) was calculated and estimated to be 0.24 in one million.
The estimated risk is using the OEHHA Derived Method and a 30 year residential exposure period.

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

Sub-Chronic Lead Exposure Risk <1.0E-08 ug/m^3

The 30-day lead concentration at the Maximum Offsite Concentration (MOC) is estimated to be less than 1.0E-08 ug/m^3 which is below the High Exposure Scenario approval level of 0.12 ug/m^3 in the ARB Risk Management Guidelines for Lead, 2001. Lead emissions were estimated based on annual emissions being emitted in 30-days.

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. 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 have not been determined to be 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

Diesel particulate exhaust is a surrogate for all toxic air contaminant annual emissions from diesel-fueled engines when determining the potential cancer risk and noncancer chronic hazard index. Speciated toxic air contaminant hourly emissions are used when determining the potential noncancer acute hazard index.

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 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

March, 2015

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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 (ACECP) 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[a]		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

[a] **Load Step 10**

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[a]	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

[a] **Load Step 10**

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[a]	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

[a] **Load Step 10**

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

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)
Full Load	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
One Hour NOx	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.

b. Very unlikely that all 6 turbines would be operating at 25% load simultaneously.

Table 3-3, continued CECP Amendment, APCD Refined Model Inputs for Normal Operations [a,b]								
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)**
Full Load	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
Eight Hours CO	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	1.82E-02	1.44E-01
Full Load	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
24-hr SO2	Emerg. Eng.	0.140	21.34	956.95	1.503	97.32	9.57E-04	7.59E-03
25% Load	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
24-hr PM-10	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
Full Load	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
Annual NOx	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.
b. Very unlikely that all 6 turbines would be operating at 25% load simultaneously.

Table 3-3, continued CECP Amendment, APCD Refined Model Inputs for Normal Operations [a,b]								
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)**
Full Load	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
Annual SO2	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
25% Load	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
Annual PM-10	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.

b. Very unlikely that all 6 turbines would be operating at 25% load simultaneously.

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 based on NO_2/NO_x ratios measured in District source test for similar equipment:

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 (μg/m³)

	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 μg/m³.

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/m³)

Pollutant	Averaging Time	Modeled Maximum Concentrations (μg/m³)
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	12

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: 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 (the 2012 Licensed CECP).

3. The permittee shall cancel permit Application Nos. APCD2007-APP-985745, APCD2007-APP-985747, and APCD2007-APP-985748 (the 2012 Licensed CECP) on or before the date construction commences for any equipment authorized for construction under this permit.

4. Prior to the earliest initial startup date for any of the combustion turbines, the applicant shall surrender to the District Class A Emission Reduction Credits (ERCs) in an amount equivalent to 47.94 tons per year of oxides of nitrogen (NOx) to offset the net maximum allowable increase of 39.9 tons per year of NOx emissions for the equipment described in District 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. [Rule 20.3(d)(8)]

5. 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]

6. 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]

7. 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]

8. 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]

9. 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].

10. 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 date the first turbine commences operation as defined in 40 CFR §72.2. [40 CFR Part 72]

11. 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]

12. 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]

13. 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 its commissioning period. [Rule 20.3(d)(2)]

<u>COMBUSTION TURBINE CONDITIONS</u>

DEFINITIONS

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

15. Unless otherwise noted in a specific condition, 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)]

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

17. 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, 40 CFR Part 60 Appendix B and F, and 40 CFR Part 75]

18. 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, whichever comes first. 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 rounded to the nearest hundredth of an hour. [Rule 20.3(d)(1)]

19. For the purposes of this permit, initial startup shall be defined for each combustion turbine as the first time that the combustion turbine combusts fuel on-site. [Rule 20.3]

20. 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.

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

GENERAL CONDITIONS

21. 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]

22. 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 expressed in units of grains of sulfur per 100 dscf of natural gas and hourly records of the higher and lower heating values of the natural gas expressed in units of Btu/scf. These records shall be provided 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)]

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

EMISSION LIMITS

24. 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, 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, 40 CFR Part 60 Appendix B and F, and 40 CFR Part 75]

25. 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, 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, 40 CFR Part 60 Appendix B and F, and 40 CFR Part 75]

26. 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)]

27. 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)]

28. 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)(2)]

29. 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, 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 VOC/CO surrogate relationship and the CO CEMS data averaged over a 1-clock-hour period shall be used. The VOC/CO surrogate relationship shall be verified and/or modified, if necessary, based on source testing. [Rule 20.3(d)(1)]

30. 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 periods for that turbine. [Rule 1200]

31. When a combustion turbine is operating, the emission concentration of NOx, calculated as nitrogen dioxide (NO_2), shall not exceed 42 ppmvd averaged over each 1-clock-hour period and corrected to 15% oxygen, except for startup and shutdown periods for that turbine, as defined in Rule 69.3. [Rule 69.3]

32. 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 averaged over each 1-clock-hour period and corrected to 15% oxygen, except for startup and shutdown periods for that turbine, as defined in Rule 69.3.1. This limit does not apply during any period in which the facility is subject to a variance from the emission limits contained in Rule 69.3.1. [Rule 69.3.1]

33. When a combustion turbine is operating without any post-combustion air pollution control equipment that controls oxides of nitrogen (NOx) emissions, the emission concentration of NOx calculated as nitrogen dioxide (NO_2) from each turbine shall not exceed 22.6 parts per million by

volume on a dry basis (ppmvd) averaged over each 1-clock-hour period and corrected to 15% oxygen, except for periods of startup and shutdown, as defined in Rule 69.3.1. This limit does not apply during any period in which the facility is subject to a variance from the emission limits contained in Rule 69.3.1. [Rule 69.3.1]

34. For each rolling four 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 four 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 four unit operating hour period:

	Case	**Emission Limit, ppmvd at 15% O_2**	**Emission Limit, lb/MWh**
i.	All four hours at or above 75% Load	15	0.43
ii.	All four hours 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 = the number of unit operating hours in the four hour 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]

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

36. The emissions of particulate matter less than or equal to 10 microns in diameter (PM_{10}) from the exhaust stacks of the combustion turbines 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)]

37. The discharge of particulate matter from the exhaust stack of each combustion turbine shall not exceed 0.10 grains per dry standard cubic foot (0.23 grams/dscm) corrected to 12% carbon dioxide. The District may require periodic testing to verify compliance with this standard. [Rule 53]

38. Visible emissions from the lube oil vents and the exhaust stack of each combustion turbine shall not exceed 20% opacity for more than three (3) minutes in any period of 60 consecutive minutes. [Rule 50]

39. Mass emissions from each combustion turbine of oxides of nitrogen (NOx), calculated as NO_2; carbon monoxide (CO); and volatile organic compounds (VOC), calculated as methane, shall not exceed the following limits, except during commissioning, startup and shutdown periods for that turbine. A 1-clock-hour averaging period for these limits shall be used when compliance is determined using CEMS data.

Pollutant		**Emission Limit, lb/hr**
a.	NOx	9.1
b.	CO	8.8
c.	VOC	2.5

[Rule 20.3(d)(2)]

40. Excluding any minutes that are coincident with a shutdown period, cumulative 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 during each of that turbine's startup periods, except during that turbine’s commissioning period.

	Pollutant	**Emission Limit, lb**
a.	NOx	14.7
b.	CO	7.4
c.	VOC	2.0

[NOx and VOC: Rule 20.3(d)(1); CO: Rule 20.3(d)(2)]

41. Cumulative 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 during each of that turbine's shutdown periods, 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)]

42. Emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2), from each combustion turbine shall not exceed 90 pounds per hour measured over each 1-clock-hour period. In addition, the emission concentration of NOx, calculated as NO_2, from each turbine shall not exceed 100 parts per million by volume on a dry basis (ppmvd) averaged over each 1-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 for that turbine. [Rule 20.3(d)(2)]

43. 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) averaged over each 1-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 periods. [Rule 20.3(d)(2)(i)]

44. 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) as it exists on the date the permit to operate for this equipment is approved, and except for CO emissions during any rolling 12-calendar-month period in which a turbine commissioning period occurs, shall not exceed the following limits for each rolling 12-calendar-month period, beginning with the 12-calendar-month period that begins 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	84.18
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, except for CO emissions during any rolling 12-calendar month period in which a turbine commissioning period occurs. 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]

45. Total emissions of CO during any rolling 12-calendar-month period in which a turbine commissioning period occurs 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) as it exists on the date the permit to operate for this equipment is approved, shall not exceed the following limit for each rolling 12-calendar-month period, beginning with the 12-calendar-month period that begins with the month in which the earliest initial startup among the equipment authorized to be constructed under this permit occurs:

    77.8 tons per year + N x 4.05 tons/yr

    Where N=number of turbines with commissioning periods occurring within the 12-calendar-month period. 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]

46. 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 startup of the turbine occurs. 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]

47. 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 mass emission limits 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	No Limit	No Limit
2	No Limit	No Limit
3	41.57	No Limit
4	27.42	27.6
5	13.27	22.9
6	0.00	18.2

    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 startup from among the indicated number of turbines. Once a turbine has undergone its initial startup, it is included in determining the number of turbines started from the initial startup date going forward. 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]

48. 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) as it exists on the date the permit to operate for this equipment is approved. 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]

49. 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 rounded to the nearest hundredth of an hour. [Rules 1200, 20.3(d)(2) and 21]

50. For each combustion turbine, the number of startup periods occurring in each calendar year shall not exceed 400. When determining compliance with this limit, any startup that occurs during the commissioning period shall not be included. [Rules 1200, 20.3(d)(2) and 21]

51. For each combustion turbine, the number of startup periods occurring during its commissioning period shall not exceed 350. [Rules 1200, 20.3(d)(2) and 21]

AMMONIA – SCR

52. Not later than 90 calendar days prior to the start of construction, unless a later date is approved in writing by the District, 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 temperature for the SCR catalyst at which ammonia injection is feasible; the catalyst volume, catalyst material, catalyst manufacturer, space velocity and area velocity at full load; and control efficiencies of the SCR for controlling NOx emissions and the oxidation catalyst for controlling CO and VOC emissions at temperatures between the minimum and maximum operating temperatures 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]

53. When a combustion turbine is operating, ammonia shall be injected at all times that the associated selective catalytic reduction (SCR) system catalyst outlet temperature is 540 degrees Fahrenheit or greater. [Rules 20.3(d)(1)]

54. 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, unless a later date is approved in writing by the District. The monitors shall be in full operation at all times when the turbine is in operation. [Rules 20.3(d)(1)]

55. 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 each 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), 21]

56. 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. [Rules 14, 21]

TESTING

57. 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]

58. Unless otherwise specified in this permit or authorized in writing by the District, within 45 days after completion of a source test or Relative Accuracy Test Audit (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]

59. All testing conducted to measure concentrations or emissions of Volatile Organic Compounds (VOCs) shall include measurement of formaldehyde and the result shall be added to the result

determined for other VOC concentrations or emissions, as applicable. Measurement of VOC emissions shall be conducted in accordance with EPA Method 18, or alternative methods approved by the District and EPA. Measurement of emissions of formaldehyde shall be conducted in accordance with EPA Method 316 or 323, or an alternative method approved by the District and EPA.

60. 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]

61. 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 concentrations and emissions, except for formaldehyde, shall be conducted in accordance with EPA Method 18, or an alternative method approved by the District and EPA;
    c. Measurement of formaldehyde concentrations and emissions shall be conducted in accordance with EPA Method 316 or 323, as specified by the District, or an alternative method approved by the District and EPA;
    d. Total VOC concentrations and emissions shall be the sum of those concentrations and emissions determined using Method 18 and the formaldehyde concentrations and emissions;
    e. Measurements of ammonia concentrations 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;
    f. Measurements of PM_{10} emissions shall be conducted in accordance with EPA Methods 201A and 202 or an alternative method approved by the District and EPA;
    g. 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 and concentration limits of this permit and District Rules and Regulations.

h. Measurements of particulate matter emissions shall be conducted in accordance with SDAPCD Method 5 or an alternative method approved by the District and EPA;
i. Measurements of opacity shall be conducted in accordance with EPA Method 9 or an alternative method approved by the District and EPA; and
j. 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]

62. 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]

63. 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]

64. 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 turbine. 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 and other conditions of this permit 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 and other conditions of this permit. 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]

65. 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 other conditions of this permit and to 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]

66. 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]

67. 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

68. The Applicant shall comply with the applicable continuous emission monitoring requirements of 40 CFR Part 75 and 40 CFR Part 60. [40 CFR Part 75 and 40 CFR Part 60]

69. 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. Clock-hourly average concentration of oxides of nitrogen (NOx) in parts per million (ppmvd) both uncorrected and corrected to 15% oxygen;

b. Clock-hourly average concentration of carbon monoxide (CO) in parts per million (ppmvd) both uncorrected and corrected to 15% oxygen;
c. Percent oxygen (O_2) in the exhaust gas for each unit operating minute;
d. Clock-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. Calendar 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 four unit operating hour average concentration of oxides of nitrogen (NOx) in parts per million (ppmvd) corrected to 15% oxygen;
i. Rolling four unit operating hour average emission rate of oxides of nitrogen (NOx), calculated as NO_2, in pounds per megawatt-hour (lb/MWh);
j. Calendar quarter, calendar year, and rolling 12-calendar-month period mass emissions of oxides of nitrogen (NOx) calculated as NO_2, in tons;
k. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds;
l. Clock-hourly mass emissions of carbon monoxide (CO), in pounds;
m. Calendar-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) in parts per million (ppmvd) both uncorrected and corrected to 15% oxygen during each unit operating minute; and
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]

70. 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]

71. 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 and completed on 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]

72. 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]

73. 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]

74. 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]

75. 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]

76. 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]

77. 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]

78. 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 and 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]

79. 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 VOC/CO surrogate relationship that shall be used to demonstrate compliance with all VOC limits when using CEMS data. This protocol can be provided as part of the Initial Source Emissions Test Protocol. [Rule 20.3(d)(1)]

80. 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, 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]

81. Each combustion turbine shall be equipped with continuous monitors to measure, calculate, and record unit operating days, hours, minutes 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 British thermal units per standard cubic foot (Btu/scf);
    e. Stack exhaust gas temperature during each unit operating minute, in degrees Fahrenheit;
    f. Gross electrical power output during each unit operating minute in megawatts (MW); 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]

82. 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]

83. Operating logs or Data Acquisition and Handling System (DAHS) records shall be maintained to record the beginning and end times and durations of all startup and shutdown periods to the nearest minute, quantity of fuel used in each clock minute, 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 rounded to the nearest hundredth of an hour. [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

84. 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)]

85. Within 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, at a minimum, the date the commissioning period started and ended, the date and times of all startup and shutdown periods, the emissions of NOx and CO during startup and shutdown periods, and the emissions of NOx and CO during other periods. 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 during startup and shutdown periods, averaged over each hour of operation:
    a. Concentration of oxides of nitrogen (NOx) in parts per million (ppmvd) both uncorrected and corrected to 15% oxygen;
    b. Concentration of carbon monoxide (CO) in parts per million (ppmvd) both uncorrected and corrected to 15% oxygen,;
    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 British thermal units per standard cubic foot (Btu/scf);
    j. Gross electrical power output of the turbine, in megawatts (MW);
    k. SCR outlet temperature, in degrees Fahrenheit;
    l. Water injection rate in gallons per minute (gpm) or pounds per hour (lb/hr); and

m. Ammonia injection rate in 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)]

86. 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

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

88. 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]

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

90. 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

91. 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)]

92. 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]

93. 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]

94. 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.

95. 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]

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

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

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

99. 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]

100. 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]

101. 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]

102. 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]

103. 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]

104. 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]

105. 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]

CONDITIONS FOR EMERGENCY ENGINE (GENERATOR)

106. 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)]

107. 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]

108. 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]

109. 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.

110. 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]

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

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

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

114. 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]

115. 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]

116. 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]

117. 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]

118. 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]

119. 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]

120. 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]

121. 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]

Appendix E: Proposed ERCs

Summary of Emission Reduction Credits (ERCs) Proposed as Offsets

ER Certificate No.	Original Issue Date	Type	Pollutant	ERC Amount, tons per	NOx Equivalent Amount, tons	Location of Emission Reductions	Description Emission Reduction	Current Owner
978938-05	6/30/2004	Class A	NOx	35.3	35.3	Naval Air Station—North Island; Foot of Neville Road, Naval Training Center, San Diego; Vesta Street & Ward Road Naval Station San Diego	Permanent shutdown of peaking combustion turbines	Cabrillo Power II, LLC
981518-01	8/01/2006	Class A	NOx	2.3	2.3	3200 Harbor Drive, San Diego	Permanent shutdown of peaking combustion	Cabrillo Power II, LLC
983809-02	9/22/2005	Class A	VOCs	25.1	12.55	2145 East Belt Street, San Diego	Additional VOC controls at a kelp processing facility.	Grey K Environmental Fund, LP
Total					**50.15**			

Appendix F: VOC and PM Source Test Data

Table F1: VOC Data (Mariposa + LMS100s)

Source	Description	Method	Date	Run	Value	Unit	Value	Unit	Comments
Mariposa (Unit 600)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	Not Provided	2/11/2014	1	0.39	ppm 15%	0.0014	lb/MM Btu	POC -
				2	0.38		0.0014		
				3	0.39		0.0014		
				A	0.39		0.0014		
Mariposa (Unit 700)	General Electric (GE) LM6000 PC-Sprint. 50 MW.		2/12/2014	1	0.39	ppm 15%	0.0014	lb/MM Btu	POC -
				2	0.38		0.0014		
				3	0.38		0.0014		
				A	0.38		0.0014		
Mariposa (Unit 800)	General Electric (GE) LM6000 PC-Sprint. 50 MW.		2/13/2014	1	0.4	ppm 15%	0.0015	lb/MM Btu	POC -
				2	0.39		0.0014		
				3	0.4		0.0015		
				A	0.4		0.0015		
Mariposa (Unit 900)	General Electric (GE) LM6000 PC-Sprint. 50 MW.		2/14/2014	1	0.39	ppm 15%	0.0014	lb/MM Btu	POC -
				2	0.38		0.0014		
				3	0.38		0.0014		
				A	0.38		0.0014		
Mariposa (Unit 600)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 18, EPA TO-12	7/30/2012 - 7/31/2012	1	0.73	ppm 15%	0.00094	lb/MM Btu	POC. 42-46 MW
				2	0.59		0.00076		
				3	0.52		0.00067		
				A	0.61		0.00079		
Mariposa (Unit 700)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 18, EPA TO-12	8/1/2012 - 8/2/2012	1	0.42	ppm 15%	0.00054	lb/MM Btu	POC. 42-45 MW
				2	0.47		0.0006		
				3	0.35		0.00045		
				A	0.41		0.00053		
Mariposa (Unit 800)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 18, EPA TO-12	8/6/2012 - 8/7/2012	1	0.46	ppm 15%	0.00059	lb/MM Btu	POC. 46-48 MW
				2	0.32		0.00041		
				3	0.37		0.00048		
				A	0.39		0.0005		
Mariposa (Unit 900)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 18, EPA TO-12	8/4/2012	1	0.71	ppm 15%	0.00091	lb/MM Btu	POC. 46-48 MW
				2	1.03		0.00132		
				3	0.64		0.00083		
				A	0.79		0.00102		
Mariposa (Unit 600)	General Electric (GE) LM6000 PC-	Not Provided	2/11/2013	1	0.3551	ppm 15%	0.0013	lb/MM Btu	POC. 51 MW
				2	0.3381		0.0013		
				3	0.188		0.0007		

	Sprint. 50 MW.			A	0.2938		0.0011		
				1	0.2		0.0007		
				2	0.23		0.0009		
				3	0.19		0.0007		
Mariposa (Unit 700)	General Electric (GE) LM6000 PC-Sprint. 50 MW.		2/12/2013	A	0.2063	ppm 15%	0.0008	lb/MM Btu	POC. 51 MW
				1	0.318		0.0053		
				2	0.337		0.0052		
				3	0.304		0.0051		
Mariposa (Unit 800)	General Electric (GE) LM6000 PC-Sprint. 50 MW.		2/14/2013	A	0.3196	ppm 15%	0.0052	lb/MM Btu	POC. 51 MW
				1	0.19		0.0007		
				2	0.29		0.0011		
				3	0.3		0.0011		
Mariposa (Unit 900)	General Electric (GE) LM6000 PC-Sprint. 50 MW.		2/15/2013	A	0.259	ppm 15%	0.001	lb/MM Btu	POC. 51 MW
				1	0.2		0		
				2	0.4		0.001		
				3	0.2		0		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/30/2009	A	0.3	ppm 15%	0	lb/MM Btu	Full load. Appears to also use M18
				1	0.1		0		
				2	0.2		0		
				3	0.1		0		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/27/2009	A	0.2	ppm 15%	0	lb/MM Btu	Full load. Appears to also use M18
				1	0.2		0		
				2	0.8		0.001		
				3	0.1		0		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/23/2009	A	0.4	ppm 15%	0	lb/MM Btu	Full load. Appears to also use M18
				1	0.3		0		
				2	0.1		0		
				3	0.2		0		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/24/2009	A	0.2	ppm 15%	0	lb/MM Btu	Full load. Appears to also use M18
				1	0		0		
				2	0		0		
				3	0		0		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 18, EPA TO-12	5/11/2010	A	0.11	ppm 15%	0.0001	lb/MM Btu	Load/Method not stated. Values reported as <0.11 and <0.0001. Only includes C3-C6. Reported based on detection limit of propane
				1	0		0		
				2	0		0		
				3	0		0		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 18, EPA TO-12	5/12/2010	A	0.11	ppm 15%	0.0001	lb/MM Btu	Load/Method not stated. Values reported as <0.11 and <0.0001. Only includes C3-C6. Reported based on detection limit of propane
				1	0		0		
				2	0		0		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 18, EPA TO-12	5/18/2010	3	0	ppm 15%	0	lb/MM Btu	Load/Method not stated. Values reported as <0.11 and <0.0001. Only includes C3-C6. Reported based on detection limit

				A	0.11		0.0001		of propane
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 18, EPA TO-12	5/19/2010	1	0	ppm 15%	0	lb/MM Btu	Load/Method not stated. Values reported as <0.11 and <0.0001. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.11		0.0001		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 18, EPA TO-12	5/13/2011	1	0	ppm 15%	0	lb/MM Btu	Load/Method not stated. Values reported as <0.22 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.22		0.0003		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 18, EPA TO-12	5/12/2011	1	0	ppm 15%	0	lb/MM Btu	Load/Method not stated. Values reported as <0.22 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.22		0.0003		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 18, EPA TO-12	5/11/2011	1	0	ppm 15%	0	lb/MM Btu	Load/Method not stated. Values reported as <0.11 and <0.0001. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.22		0.0003		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 18, EPA TO-12	5/10/2011	1	0	ppm 15%	0	lb/MM Btu	Load/Method not stated. Values reported as <0.11 and <0.0001. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.22		0.0003		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/27/2012	1	0	ppm 15%	0	lb/MM Btu	Load/Method not stated. Values reported as <0.42 and <0.0005. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.42		0.0005		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/26/2012	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.41 and <0.0005. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.41		0.0005		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/25/2012	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.41 and <0.0005. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.41		0.0005		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/24/2012	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.42 and <0.0005. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.42		0.0005		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/23/2013	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.22 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.22		0.0003		

Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/24/2013	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.22 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.22		0.0003		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/24/2013	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.22 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.22		0.0003		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/24/2013	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.22 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.22		0.0003		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/22/2014	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.20 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.2		0.0003		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/23/2014	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.20 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.2		0.0003		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/24/2014	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.20 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.2		0.0003		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 18, EPA TO-12	4/25/2014	1	0	ppm 15%	0	lb/MM Btu	Values reported as <0.20 and <0.0003. Only includes C3-C6. Reported based on detection limit of propane
				2	0		0		
				3	0		0		
				A	0.2		0.0003		
Walnut Creek (Turbine 1)	General Electric (GE) LMS100	EPA 18, EPA TO-12	1/19/2013 to 1/22/2013	1 - 100%	0.69	ppm 15%	NA		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load
				2 - 75%	0.62				
				3 - 50%	0.73				
				A	0.68				
Walnut Creek (Turbine 2)	General Electric (GE) LMS100	Modified SCAQMD 25.3	1/29/2013 to 1/30/2013 & 2/5/2013	1 - 100%	0.8	ppm 15%			SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load
				2 - 75%	0.56				
				3 - 50%	0.7				
				A	0.69				
Walnut Creek (Turbine 3)	General Electric (GE) LMS100	Modified SCAQMD 25.3	2/20/2013 to 2/25/2013	1 - 100%	0.53	ppm 15%			SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load. Includes data below
				2 - 75%	0.54				
				3 - 50%	0.6				

				A	0.56			detection limit
Walnut Creek (Turbine 4)	General Electric (GE) LMS100	Modified SCAQMD 25.3	2/27/2013 to 3/1/2013	1 - 100% 2 - 75% 3 - 50% A	0.52 0.56 0.57 0.55	ppm 15%		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load. Includes data below detection limit
Walnut Creek (Turbine 5)	General Electric (GE) LMS100	Modified SCAQMD 25.3	3/25/2013 to 3/28/2013	1 - 100% 2 - 75% 3 - 50% A	0.51 0.54 0.61 0.55	ppm 15%		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load. Includes data below detection limit
CPV Sentinel (Turbine 1)	General Electric (GE) LMS100	Modified SCAQMD 25.3	1/15/2013 to 1/17/2013	1 - 100% 2 - 75% 3 - 50% A	1.67 0.61 1.48 1.25	ppm 15%		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load
CPV Sentinel (Turbine 2)	General Electric (GE) LMS100	Modified SCAQMD 25.3	1/30/2013 to 2/1/2013	1 - 100% 2 - 75% 3 - 50% A	0.75 0.55 0.68 0.66	ppm 15%		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load
CPV Sentinel (Turbine 3)	General Electric (GE) LMS100	Modified SCAQMD 25.3	2/2/2013 to 2/4/2013 & 2/13/13	1 - 100% 2 - 75% 3 - 50% A	0.52 0.52 1.55 0.86	ppm 15%		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load
CPV Sentinel (Turbine 4)	General Electric (GE) LMS100	Modified SCAQMD 25.3	2/11/2013 to 2/12/2013 & 2/22/13	1 - 100% 2 - 75% 3 - 50% A	0.58 0.56 0.55 0.56	ppm 15%	NA	SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load
CPV Sentinel (Turbine 5)	General Electric (GE) LMS100	Modified SCAQMD 25.3	2/27/2013 to 3/19/2014	1 - 100% 2 - 75% 3 - 50% A	0.51 0.51 0.59 0.54	ppm 15%		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load. Includes data below detection limit
CPV Sentinel (Turbine 6)	General Electric (GE) LMS100	Modified SCAQMD 25.3	2/25/2013 to 2/28/2013	1 - 100% 2 - 75% 3 - 50% A	0.5 0.51 0.55 0.52	ppm 15%		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load. Includes data below detection limit
CPV Sentinel (Turbine 7)	General Electric (GE) LMS100	Modified SCAQMD	3/19/2013 to 3/24/2013 & 4/07/13	1 - 100% 2 - 75%	0.47 0.59	ppm 15%		SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not

		25.3		3 - 50%	0.67				weighted for load. Includes data below detection limit
				A	0.58				
CPV Sentinel (Turbine 8)	General Electric (GE) LMS100	Modified SCAQMD 25.3	4/5/2013 to 4/7/2013 & 4/22/13	1 - 100%	0.42	ppm 15%			SCAQMD Modified Method 25.3. Average is calculated as an average of three tests, not weighted for load. Includes data below detection limit
				2 - 75%	1.61				
				3 - 50%	0.49				
				A	0.84				
Waterbury Generation Facility	General Electric (GE) LMS100	EPA 25A	6/22/2009	1	1.2	ppm 15%	1.4	lb/hr	25A
				2	1.1		0.6		
				3	0.4		0.4		
				A	0.9		0.8		

Table F-2: VOC Data for LM6000 Sprint turbines in County of San Diego

Facility	Unit	Test Date	Method	Species	1	2	3	DUP 1	Average	SD
Orange Grove	1	5/13/2010	18	CH4	5.11	7.02	8.92		7.02	1.91
Orange Grove	1	5/13/2010	18	VOC at 15% O2					<.09	N/A
Orange Grove	1	12/15/2010	25	THC	5.199	5.721	5.785		5.57	0.32
Orange Grove	1	12/15/2010	18	CH4	4.539	4.34	4.405		4.43	0.10
Orange Grove	1	12/15/2010	18	C2H6	0.239	0.239	0.239		0.24	0.00
Orange Grove	1	12/15/2010		TCH4&CH6	4.778	4.579	4.644		4.67	0.10
Orange Grove	1	12/15/2010		O2 %	15.48	15.46	15.42			
Orange Grove	1	12/15/2010	25 - 18 (CH4 &C2H6)	VOC at 15% O2	0.458	1.239	1.228		0.98	0.45
Orange Grove	1	5/20/2011	25	THC	6.455	6.423	6.577		6.49	0.08
Orange Grove	1	5/20/2011	18	CH4	5.594	5.327	5.878		5.60	0.28
Orange Grove	1	5/20/2011	18	C2H6	0.249	0.249	0.249		0.25	0.00
Orange Grove	1	5/20/2011		TCH4&CH6	5.843	5.576	6.127		5.85	0.28
Orange Grove	1	5/20/2011		O2 %	15.2	15.35	15.24			
Orange Grove	1	5/20/2011	25 - 18 (CH4 &C2H6)	VOC at 15% O2	0.633	0.900	0.469		0.67	0.22
Orange Grove	2	4/28/2010	18	CH4	1.28	1.21	1.35		1.28	0.07
Orange Grove	2	4/28/2010	18	C2H4	0.34	0.68	0.59		0.54	0.18
Orange Grove	2	4/28/2010	18	C2H6	1.22	2.59	1.92		1.91	0.69
Orange Grove	2	4/28/2010	Dilution Corrected	CH4	2.56	2.42	2.7		2.56	0.14
Orange Grove	2	4/28/2010		C2H4	0.68	1.36	1.18		1.07	0.35
Orange Grove	2	4/28/2010		C2H6	2.44	5.18	3.84		3.82	1.37
Orange Grove	2	4/28/2010		O2 %	14.86	14.88	14.94			
Orange Grove	2	4/28/2010		VOC at 15% O2 w/ nd	0.85	1.26	1.37		1.16	0.27
Orange Grove	2	4/28/2010		Nondetects (at 1/2)	0.1858	-0.0729	0.2019		0.10	0.15
Orange Grove	2	4/28/2010		VOC detected	0.664	1.33	1.168		1.06	0.35
Orange Grove	2	12/17/2010	25	THC	2.194	4.039	1.648		2.63	1.25
Orange Grove	2	12/17/2010	18	CH4	1.943	4.188	2.096		2.74	1.25
Orange Grove	2	12/17/2010	18	C2H6	0.241	0.241	0.241		0.24	0.00
Orange Grove	2	12/17/2010		TCH4&CH6	2.184	4.429	2.337		2.98	1.25
Orange Grove	2	12/17/2010		O2 %	15.48	15.46	15.42			
Orange Grove	2	12/17/2010	25 - 18 (CH4 &C2H6)	VOC at 15% O2	0.01089	-0.423	-0.7418		-0.38	0.38
Orange Grove	2	5/25/2011	25	THC	9.304	8.812	9.661		9.26	0.43
Orange Grove	2	5/25/2011	18	CH4	7.366	6.779	7.524		7.22	0.39

Orange Grove	2	5/25/2011	18	C2H6	0.249	0.249	0.249		0.25	0.00
Orange Grove	2	5/25/2011		TCH4&CH6	7.615	7.028	7.773		7.47	0.39
Orange Grove	2	5/25/2011		O2 %	15.49	15.49	15.5			
Orange Grove	2	5/25/2011	25 - 18 (CH4 &C2H6)	VOC at 15% O2	1.842	1.946	2.06		1.95	0.11
Orange Grove	1	6/4/2013	25A	THC	2.11	1.88	1.97		1.99	0.12
Orange Grove	1	6/4/2013	18	CH4	4.19	3.59	3.98		3.92	0.30
Orange Grove	1	6/4/2013	18	C2H6	0	0	0		0.00	0.00
Orange Grove	1	6/4/2013		TCH4&CH6	4.19	3.59	3.98		3.92	0.30
Orange Grove	1	6/4/2013		O2 %	15.07	14.99	15.01		15.02	0.04
Orange Grove	1	6/4/2013	25 - 18 (CH4 &C2H6)	VOC at 15% O2	-2.104	-1.70	-2.01		-1.94	0.21
Orange Grove	1	10/21/2014	25	THC	4.11	4.01	3.99		4.04	0.06
Orange Grove	1	10/21/2014	18	CH4	3.85	3.75	3.64		3.75	0.11
Orange Grove	1	10/21/2014	18	C2H6	0	0	0		0.00	0.00
Orange Grove	1	10/21/2014		TCH4&CH6	3.85	3.75	3.64		3.75	0.11
Orange Grove	1	10/21/2014		O2 %	15.06	15.09	15.13		15.09	0.04
Orange Grove	1	10/21/2014	25 - 18 (CH4 &C2H6)	VOC at 15% O2	0.263	0.264	0.358		0.29	0.05
El Cajon Energy		7/30/2010	18	Methane	10.2	3.8	3.1		5.70	3.91
El Cajon Energy		7/30/2010	18	Non-methane C1	ND	ND	ND			
El Cajon Energy		7/30/2010	18	Ethane	ND	ND	ND			
El Cajon Energy		7/30/2010	18	Non-ethane C2	ND	ND	ND			
El Cajon Energy		7/30/2010	18	C3	ND	ND	ND			
El Cajon Energy		7/30/2010	18	C5	ND	ND	ND			
El Cajon Energy		7/30/2010	18	C6	ND	ND	ND			
El Cajon Energy		7/30/2010		O2 %*	15	15	15			
El Cajon Energy		7/30/2010	18	VOC at 15% O2*	1	1	1	*stack O2 not provided. VOC based on 1/2 methane detection limit for C2-C6.		
El Cajon Energy		7/14/2011	18	Methane	1.05	1.11	1.07		1.077	0.0306
El Cajon Energy		7/14/2011	18	Ethene	ND	ND	ND			
El Cajon Energy		7/14/2011	18	Ethane	ND	ND	ND			

El Cajon Energy		7/14/2011	18	C3	ND	ND	ND			
El Cajon Energy		7/14/2011	18	C4	ND	ND	ND			
El Cajon Energy		7/14/2011	18	C5	ND	ND	ND			
El Cajon Energy		7/14/2011	18	C6	ND	ND	ND			
El Cajon Energy		7/14/2011	18	>C6	ND	ND	ND			
El Cajon Energy		7/14/2011		O2 %	14.58	14.58	14.65			
El Cajon Energy		7/14/2011	18	VOC at 15% O2*	0.187	0.187	0.189	*(based on 1/2 methane detection limit for C2-C6). Reported as 0 in the report.		
El Cajon Energy		7/12/2012	18	Methane	1.24	1.28	1.21		1.243	0.035
El Cajon Energy		7/12/2012	18	Ethene	ND	ND	ND			
El Cajon Energy		7/12/2012	18	Ethane	ND	ND	ND			
El Cajon Energy		7/12/2012	18	C3	ND	ND	ND			
El Cajon Energy		7/12/2012	18	C4	ND	ND	ND			
El Cajon Energy		7/12/2012	18	C5	ND	ND	ND			
El Cajon Energy		7/12/2012	18	C6	ND	ND	ND			
El Cajon Energy		7/12/2012	18	>C6	ND	ND	ND			
El Cajon Energy		7/12/2012		O2 %	14.92	14.88	14.86			
El Cajon Energy		7/12/2012	18	VOC at 15% O2*	0.1973	0.196	0.1954	*(based on 1/2 methane detection limit for C2-C6). Reported as 0 in the report.		
El Cajon Energy		7/12/2013	18	Methane	1.64	1.56	1.52		1.5733	0.0611
El Cajon Energy		7/12/2013	18	Ethene	ND	ND	ND			
El Cajon Energy		7/12/2013	18	Ethane	ND	ND	ND			
El Cajon Energy		7/12/2013	18	C3	ND	ND	ND			
El Cajon Energy		7/12/2013	18	C4	ND	ND	ND			
El Cajon		7/12/2013	18	C5	ND	ND	ND			

Energy										
El Cajon Energy		7/12/2013	18	C6	ND	ND	ND			
El Cajon Energy		7/12/2013	18	>C6	ND	ND	ND			
El Cajon Energy		7/12/2013		O2 %	14.81	14.65	14.67			
El Cajon Energy		7/12/2013	18	VOC at 15% O2*	0.19376026	0.1888	0.189406	*(based on 1/2 methane detection limit for C2-C6). Reported as 0 in the report.		
El Cajon Energy		7/17/2014	18	Methane	0.84	0.9	0.83		0.8567	0.0379
El Cajon Energy		7/17/2014	18	Ethene	ND	ND	ND			
El Cajon Energy		7/17/2014	18	Ethane	ND	ND	ND			
El Cajon Energy		7/17/2014	18	C3	ND	ND	ND			
El Cajon Energy		7/17/2014	18	C4	ND	ND	ND			
El Cajon Energy		7/17/2014	18	C5	ND	ND	ND			
El Cajon Energy		7/17/2014	18	C6	ND	ND	ND			
El Cajon Energy		7/17/2014	18	>C6	ND	ND	ND			
El Cajon Energy		7/17/2014		O2 %	14.72	14.75	14.77			
El Cajon Energy		7/17/2014	18	VOC at 15% O2*	0.19093851	0.19187	0.192496	*(based on 1/2 methane detection limit for C2-C6). Reported as 0 in the report.		

Table F-2: PM-10 Data for LMS100 Turbines

Source	Description	Method	Date	Run	Value	Unit	Value	Unit	Comments
Mariposa (Unit 600)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	2/11/2014	1	0.835	lb/hr	0.0008	lb/MMBtu	Front+Back. Test run 2 lb/hr is assumed to be invalid. 50 MW
				2	0		0.001		
				3	1.021		0.0008		
				A	0.928		0.0009		
Mariposa (Unit 700)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	2/12/2014	1	0.898	lb/hr	0.0002	lb/MMBtu	Front+Back. 50 MW
				2	1.09		0.0002		
				3	1.805		0.0004		
				A	1.264		0.0003		
Mariposa (Unit 800)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	2/13/2014	1	0	lb/hr	0	lb/MMBtu	Front+Back. Test runs with 0 PM? 50 MW
				2	2.519		0.0005		
				3	0		0		
				A	0.84		0.0002		
Mariposa (Unit 900)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	2/14/2014	1	0.895	lb/hr	0.0002	lb/MMBtu	Front+Back. Test runs with 0 PM? 50 MW
				2	0		0		
				3	0		0		
				A	0.298		0.0001		
Mariposa (Unit 600)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	7/30/2012 - 7/31/2012	1	0.515	lb/hr	0.0014	lb/MMBtu	Front+Back. 43-45 MW. Data is reported at below limit of detection
				2	0.851		0.00214		
				3	0.567		0.00143		
				A	0.64		0.00165		
Mariposa (Unit 700)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	8/1/2012-8/2/2012	1	0.214	lb/hr	0.00052	lb/MMBtu	Front+Back. 42-47 MW. Data is reported at below limit of detection
				2	0.189		0.00044		
				3	0.154		0.00041		
				A	0.185		0.00046		
Mariposa (Unit 800)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	8/6/2012 - 8/7/2012	1	0.164	lb/hr	0.00036	lb/MMBtu	Front+Back. 45-47 MW. Data is reported at below limit of detection
				2	0.8		0.00018		
				3	0.148		0.00036		
				A	0.363		0.00083		
Mariposa (Unit 900)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	8/4/2012 - 8/5/2012	1	0.282	lb/hr	0.0006	lb/MMBtu	Front+Back. 50.7 MW. Data is reported at below limit of detection
				2	0.326		0.00071		
				3	0.162		0.00036		
				A	0.257		0.00056		
Mariposa (Unit 600)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	2/11/2013	1	4.094	lb/hr	0.0008	lb/MMBtu	Front+Back. 50 MW.
				2	5.064		0.001		
				3	4.4		0.0008		
				A	4.519		0.0009		
Mariposa (Unit 700)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	2/12/2013 - 2/16/2013	1	3.892	lb/hr	0.0007	lb/MMBtu	Front+Back. 50 MW.
				2	4.167		0.0007		
				3	2.753		0.0004		

				A	3.604		0.0006		
Mariposa (Unit 800)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	2/14/2013	1	2.626	lb/hr	0.0006	lb/MMBtu	Front+Back. 50 MW.
				2	2.156		0.0005		
				3	2.039		0.0005		
				A	2.274		0.0005		
Mariposa (Unit 900)	General Electric (GE) LM6000 PC-Sprint. 50 MW.	EPA 5 + EPA 202	2/15/2013	1	2.465	lb/hr	0.0004	lb/MMBtu	Front+Back. 50 MW.
				2	2.777		0.0005		
				3	2.268		0.0004		
				A	2.503		0.0004		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/30/2009	1	1.7	lb/hr	0.002	lb/MMBtu	Full load. Front half method 5, back half 202
				2	2.29		0.002		
				3	3.59		0.004		
				A	2.53		0.003		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/27/2009	1	4.23	lb/hr	0.005	lb/MMBtu	Full load. Front half method 5, back half 202
				2	2.85		0.003		
				3	0.98		0.001		
				A	2.69		0.003		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/23/2009	1	11.16	lb/hr	0.012	lb/MMBtu	Full load. Front half method 5, back half 202
				2	2.23		0.002		
				3	1.53		0.002		
				A	4.98		0.005		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/24/2009	1	1.6	lb/hr	0.002	lb/MMBtu	Full load. Front half method 5, back half 202
				2	6.69		0.007		
				3	5.59		0.006		
				A	4.63		0.005		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 5 + EPA 202	5/11/2010	1	2.769	lb/hr	0.00279	lb/MMBtu	Load/Method not stated
				2	2.184		0.00213		
				3	1.767		0.00169		
				A	2.24		0.0022		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 5 + EPA 202	5/12/2010	1	1.43	lb/hr	0.00141	lb/MMBtu	Load/Method not stated
				2	1.104		0.00107		
				3	1.591		0.00155		
				A	1.375		0.00134		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 5 + EPA 202	5/18/2010	1	1.747	lb/hr	0.00168	lb/MMBtu	Load/Method not stated
				2	1.845		0.00176		
				3	1.58		0.00149		
				A	1.724		0.00164		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 5 + EPA 202	5/19/2010	1	2.529	lb/hr	0.00249	lb/MMBtu	Load/Method not stated
				2	2.021		0.00198		
				3	3.128		0.0031		
				A	2.559		0.00252		

				1	2.922		0.00298		
				2	2.581		0.00261		
				3	1.69		0.00167		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 5 + EPA 202	5/13/2011	A	2.388	lb/hr	0.00242	lb/MMBtu	Load/Method not stated
				1	4.098		0.00402		
				2	2.004		0.00192		
				3	1.844		0.00169		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 5 + EPA 202	5/12/2011	A	2.549	lb/hr	0.00254	lb/MMBtu	Load/Method not stated
				1	3.185		0.00314		
				2	4.34		0.0042		
				3	6.146		0.00605		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 5 + EPA 202	5/11/2011	A	4.557	lb/hr	0.00446	lb/MMBtu	Load/Method not stated
				1	1.834		0.00184		
				2	1.837		0.00182		
				3	1.832		0.00185		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 5 + EPA 202	5/10/2011	A	1.834	lb/hr	0.00184	lb/MMBtu	Load/Method not stated
				1	1.48		0.00142		
				2	1.23		0.00117		
				3	1.39		0.00133		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/27/2012	A	1.37	lb/hr	0.00131	lb/MMBtu	Load/Method not stated
				1	1.22		0.00119		
				2	1.23		0.00119		
				3	1.8		0.00174		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/26/2012	A	1.42	lb/hr	0.00137	lb/MMBtu	Load/Method not stated
				1	1.89		0.00182		
				2	1.32		0.00127		
				3	0.98		0.00096		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/25/2012	A	1.4	lb/hr	0.00135	lb/MMBtu	Load/Method not stated
				1	3.14		0.0031		
				2	1.9		0.00185		
				3	1.56		0.00151		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/24/2012	A	2.2	lb/hr	0.00215	lb/MMBtu	Load/Method not stated
				1	6.42		0.00615		
				2	4.6		0.00447		
				3	3.55		0.00342		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/23/2013	A	4.86	lb/hr	0.00468	lb/MMBtu	Load/Method not stated
				1	4.69		0.00463		
				2	4.07		0.00403		
				3	3.36		0.00326		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/24/2013	A	4.04	lb/hr	0.00397	lb/MMBtu	Load/Method not stated

Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/24/2013	1	4.18	lb/hr	0.00406	lb/MMBtu	Load/Method not stated
				2	3.25		0.00316		
				3	2.79		0.0027		
				A	3.41		0.0033		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/26/2013	1	2.64	lb/hr	0.00261	lb/MMBtu	Load/Method not stated
				2	2.34		0.00229		
				3	2.9		0.00282		
				A	2.63		0.00258		
Panoche (Turbine 1)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/22/2014	1	2.11	lb/hr	0.00206	lb/MMBtu	Load/Method not stated
				2	1.87		0.00179		
				3	1.97		0.00189		
				A	1.98		0.00191		
Panoche (Turbine 2)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/23/2014	1	1.59	lb/hr	0.00149	lb/MMBtu	Load/Method not stated
				2	2.12		0.00196		
				3	3.11		0.00291		
				A	2.27		0.00212		
Panoche (Turbine 3)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/24/2014	1	2.95	lb/hr	0.00275	lb/MMBtu	Load/Method not stated
				2	2.91		0.00275		
				3	2.94		0.00275		
				A	2.93		0.00275		
Panoche (Turbine 4)	General Electric (GE) LMS100	EPA 5 + EPA 202	4/25/2014	1	1.5	lb/hr	0.00144	lb/MMBtu	Load/Method not stated
				2	2.26		0.00217		
				3	NA		NA		
				A	1.88		0.00181		
Walnut Creek (Turbine 1)	General Electric (GE) LMS100	SCAQ MD 5.1 + EPA 201A/202	1/19/2013 to 1/22/2013	1 - 100 %	1.47	lb/hr	1.83	lb/MMscf	Higher of methods shown
				2 - 75%	NA		NA		
				3 - 50%	NA		NA		
				A	1.47		1.83		
Walnut Creek (Turbine 2)	General Electric (GE) LMS100	SCAQ MD 5.1 + EPA 201A/202	1/29/2013 to 1/30/2013 & 2/5/2013	1 - 100 %	1.94	lb/hr	0.889	lb/MMscf	Higher of methods shown
				2 - 75%	NA		NA		
				3 - 50%	NA		NA		
				A	1.94		0.889		
Walnut Creek (Turbine 3)	General Electric (GE) LMS100	SCAQ MD 5.1 + EPA 201A/202	2/20/2013 to 2/25/2013	1 - 100 %	1.15	lb/hr	1.43	lb/MMscf	Higher of methods shown
				2 - 75%	NA		NA		
				3 - 50%	NA		NA		
				A	1.15		1.43		
Walnut Creek	General Electric (GE) LMS100	SCAQ MD 5.1	2/27/2013 to	1 - 100	0.76	lb/hr	0.98	lb/MMscf	Higher of methods shown

(Turbine 4)		+ EPA 201A/202	3/1/2013	%					
				2 - 75%	NA		NA		
				3 - 50%	NA		NA		
				A	0.76		0.98		
Walnut Creek (Turbine 5)	General Electric (GE) LMS100	SCAQMD 5.1 + EPA 201A/202	3/25/2013 to 3/28/2013	1 - 100 %	1.87		2.57		
				2 - 75%	NA		NA		
				3 - 50%	NA		NA		
				A	1.87	lb/hr	2.57	lb/MMscf	Higher of methods shown
CPV Sentinel (Turbine 1)	General Electric (GE) LMS100	SCAQ MD 5.1	1/15/2013 to 1/17/2013	1 - 100 %	0.86		0.98		
				2 - 75%	0.7		1		
				3 - 50%	0.76		1.42		
				A	0.77	lb/hr	1.13	lb/MMscf	"A" is an unweighted average
CPV Sentinel (Turbine 2)	General Electric (GE) LMS100	SCAQ MD 5.1	1/30/2013 to 2/1/2013	1 - 100 %	0.75		0.89		
				2 - 75%	0.49		0.71		
				3 - 50%	0.42		0.78		
				A	0.55	lb/hr	0.79	lb/MMscf	"A" is an unweighted average
CPV Sentinel (Turbine 3)	General Electric (GE) LMS100	SCAQ MD 5.1	2/2/2013 to 2/4/2013 & 2/13/13	1 - 100 %	2.85		3.19		
				2 - 75%	0.64		0.91		
				3 - 50%	0.59		1.12		
				A	1.36	lb/hr	1.74	lb/MMscf	"A" is an unweighted average
CPV Sentinel (Turbine 4)	General Electric (GE) LMS100	SCAQ MD 5.1	2/11/2013 to 2/12/2013 & 2/22/13	1 - 100 %	4.38		4.95		
				2 - 75%	1.12		1.6		
				3 - 50%	1.42		2.65		
				A	2.31	lb/hr	3.07	lb/MMscf	"A" is an unweighted average
CPV Sentinel (Turbine 5)	General Electric (GE) LMS100	SCAQ MD 5.1	2/27/2013 to 3/19/2014	1 - 100 %	0.85		0.97		
				2 - 75%	0.84		1.19		
				3 - 50%	1.02		1.9		
				A	0.90	lb/hr	1.35	lb/MMscf	"A" is an unweighted average
CPV Sentinel (Turbine 6)	General Electric (GE) LMS100	SCAQ MD 5.1	2/25/2013 to 2/28/2013	1 - 100 %	1.87		2.14		
				2 - 75%	1.02		1.47		
				3 - 50%	1.03		1.89		
				A	1.31	lb/hr	1.83	lb/MMscf	"A" is an unweighted average

CPV Sentinel (Turbine 7)	General Electric (GE) LMS100	SCAQ MD 5.1	3/19/2013 to 3/24/2013 & 4/07/13	1 - 100 %	0.76	lb/hr	0.9	lb/MMscf	"A" is an unweighted average
				2 - 75%	0.75		1.07		
				3 - 50%	0.71		1.32		
				A	0.74		1.1		
CPV Sentinel (Turbine 8)	General Electric (GE) LMS100	SCAQ MD 5.1	4/5/2013 to 4/7/2013 & 4/22/13	1 - 100 %	2.37	lb/hr	2.6	lb/MMscf	"A" is an unweighted average
				2 - 75%	0.9		1.3		
				3 - 50%	1.02		1.91		
				A	1.43		1.94		
Waterbury Generation Facility	General Electric (GE) LMS100	EPA 5	6/22/2009	1	3.37	lb/hr	NA		Only filterable
				2	2.74				
				3	0.91				
				A	2.34				