1947 Galileo Ct., Suite 103 • Davis, California 95618

YOLO-SOLANO AIR QUALITY MANAGEMENT DISTRICT

(530) 757-3650 • (800) 287-3650 • Fax (530) 757-3670

DOCKET
08-AFC-11
DATE MAR 24 2010
RECD. MAR 25 2010

March 24, 2010

Rod Jones
Project Manager
Systems Assessment and Facility Siting Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Re: Notice of Preliminary Determination of Compliance (PDOC)
Facility Number: 05586 - CPV Vaca Station (08-AFC-11)

Dear Mr. Jones:

Enclosed is a copy of the Preliminary Determination of Compliance (PDOC) (which includes Authorities to Construct C-08-267, C-08-268, C-08-269, C-08-270, and C-08-271) for Competitive Power Ventures (CPV) Vaca Station, for the proposed installation of a 660 MW combined cycle power plant to be located at Section 30, Township 6 North, Range 1 East - Mount Diablo Base Meridian (at the corner of Fry Road and Lewis Road in Solano County).

The notice of preliminary decision for this project will be published in the Vacaville Reporter newspaper approximately three days from the date of this letter. Please submit your written comments concerning this project within the 30-day comment period scheduled to begin on the date that the notice is published.

If you have any questions, please contact me at (530) 757-3667.

Sincerely,

Susan K McLaughlin

Susan K. McLaughlin
Supervising Air Quality Engineer

Enclosure: PDOC

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PRELIMINARY DETERMINATION OF COMPLIANCE EVALUATION

CPV Vaca Station Project
California Energy Commission
Application for Certification Docket #: 08-AFC-11

Facility Name:	CPV Vacaville, LLC
Mailing Address:	8403 Colesville Road; Suite 915 Silver Spring, MD 20910
Contact Name:	Andrew C. Welch
Telephone:	(240) 723-2304
Fax:	(240) 723-2339
E-Mail:	awelch@cpv.com
Alternate Contact:	Steve Hill
Telephone:	(510) 464-8028
Fax:	(916) 444-8373
Cell:	(510) 684-3671
E-Mail:	shill@sierraresearch.com
Engineer:	Courtney Graham, Associate Air Quality Engineer
Lead Engineer:	Susan K. McLaughlin, Supervising Air Quality Engineer
Date:	March 24, 2010
Facility #:	05586
Application #'s:	C-08-267, C-08-268, C-08-269, C-08-270, C-08-271

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I. PROPOSAL:

Competitive Power Ventures, LLC (CPV) is seeking approval from the Yolo-Solano Air Quality Management District (District) for the installation of an electrical power generation facility (Vaca Station) in Vacaville, Solano County, California. The proposed CPV Vaca Station project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 512 MMBtu/hr duct burner. Also proposed are a 220 MW steam turbine, a 37 MMBtu/hr auxiliary boiler, a 315 hp diesel-fired emergency IC engine powering a water pump, a 1,500 hp diesel-fired emergency IC engine powering a 1,000 kW generator and associated facilities. The plant will have a nominal rating of 660 MW.

The CPV Vaca Station Project is subject to approval by the California Energy Commission (CEC). Pursuant to YSAQMD Rule 3.4, Section 418.3, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The DOC will be issued and submitted to the CEC contingent upon YSAQMD approval of the project.

The CEC is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

Additionally, the CPV Vaca Station Project is subject to Prevention of Significant Deterioration (PSD) requirements by Environmental Protection Agency (EPA) Region IX.

II. APPLICABLE RULES:

Rule 2.3	Ringelmann Chart (1/13/10)
Rule 2.5	Nuisance (1/13/10)
Rule 2.11	Particulate Matter (1/13/10)
Rule 2.12	Specific Contaminants (6/14/78)
Rule 2.16	Fuel Burning Heat or Power Generators (1/29/79)
Rule 2.19	Particulate Matter Process Emission Rate (6/14/78)
Rule 2.27	Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (6/17/97)
Rule 2.32	Stationary Internal Combustion Engines (1/28/02)
Rule 2.34	Stationary Gas Turbines (9/3/98)
Rule 3.1	General Permit Requirements (7/07/97)
Rule 3.4	New Source Review (7/07/97)
Rule 3.8	Federal Operating Permits (4/11/01)
Rule 3.20	Ozone Transport Mitigation (12/08/04)
Rule 3.23	Acid Deposition Control (8/12/09)

Rule 5.2 Upset Breakdown Conditions (6/14/78)
Rule 9.3 Hexavalent Chromium

Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
Subpart GG - Standards of Performance for Stationary Gas Turbines
Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Subpart KKKK - Standards of Performance for Stationary Combustion Turbines
California Environmental Quality Act (CEQA)
California Code of Regulations (CCR), Section 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment)
California Health & Safety Code (CH&S), Sections 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment) 41700 (Health Risk Analysis), 42301.6 (School Notice), 44300 (Air Toxic "Hot Spots"), and 93115 (Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines)

III. PROJECT LOCATION:

The proposed equipment will be located adjacent to the Easterly Wastewater Treatment Plant (EWTP), within NE¼ of Section 30, Township 6 North, Range 1 East – Mount Diablo Base Meridian on Assessor's Parcel Number 0142-200-040 (See Attachment B). The EWTP is a separate stationary source that will be providing make-up water for the facility. The closest population center is the town of Elmira approximately 0.5 miles to the northwest. Although the proposed project is located on City of Vacaville property, the nearest population area of Vacaville is approximately 1.75 miles to the west. The City of Fairfield is located approximately 8 miles to the southwest, and the City of Dixon is located approximately 8 miles to the northeast.

The proposed site is located on a 24-acre, City of Vacaville owned parcel at the corner of Lewis Road and Fry Road, in Solano County. This location is not within 1,000 feet of a K-12 school.

IV. PROCESS DESCRIPTION:

Combined-Cycle Combustion Turbine Generators

The proposed project includes two natural gas-fired combined-cycle combustion turbine generators (CTGs – either two General Electric Frame 7FA or two Siemens SGT6 5000F) equipped with Dry Low NO_X (DLN) combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 200 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 220 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize DLN combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

CTG with DLN	
Pollutant	Emission Rate
Volatile Organic Compound (VOC)	2.0 ppmvd @ 15% O_2
Carbon Monoxide (CO)	3.0 ppmvd @ 15% O_2
Nitrogen Oxides (NO_X)	2.0 ppmvd @ 15% O_2
Sulfur Oxides (SO_X)	0.00277 lb/MMBtu*
	0.0007 lb/MMBtu**
Particulate Matter less than 10 Microns (PM_{10})	0.0039 lb/MMBtu

*Hourly and Daily Limits; based on 1.0 gr S/100 dscf
**Annual average; based on 0.25 gr S/100 dscf

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce steam. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 150 feet tall by 18.5 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 512 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 3,500 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 220 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.0 MMBtu/hr natural gas-fired boiler equipped with an ultra low NO_X burner, capable of providing up to 30,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

One 315 horsepower (hp) John Deere Model JU6H-UFAD98 diesel-fired IC engine will drive a fire pump in the event of fire at the facility. The engine will be limited to no greater than 200 hours per year of emergency and non-emergency operation in accordance with the applicant's proposal.

Diesel-Fired Emergency IC Engine Powering an Electrical Generator

One 1,500 hp Caterpillar Model C-32 ATAAC diesel-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 200 hours per year of emergency and non-emergency operation in accordance with the applicant's proposal.

V. EQUIPMENT/CONTROL EQUIPMENT LISTING:

C-08-267 **Equipment:** 37.0 MMBtu/hr natural gas-fired boiler

Control Equipment: Ultra low NOx burner

C-08-268 **Equipment:** 1500 BHP Diesel-fired Caterpillar Model C32 ATAAC, Model Year 2009, EPA Certified Tier II IC engine, powering a 1,000 KW emergency electrical generator

Control Equipment: Turbocharger and aftercooler

C-08-269 **Equipment:** 315 BHP Diesel-fired John Deere Model JU6H-UFAD98, Model Year 2009, EPA Certified Tier II IC engine, powering an emergency fire pump

Control Equipment: Turbocharger and aftercooler

C-08-270 **Equipment:** 12-cell mechanical draft cooling tower; 142,000 gpm

Control Equipment: Drift eliminators

C-08-271 **Equipment:** Two (2) 220 MW nominally rated combined-cycle power generating systems, consisting of either two General Electric Frame 7FA or two (2) Siemens SGT6 5000F natural gas-fired combustion turbine generators, two (2) heat recovery steam generators (HRSG) with 512 MMBtu/hr duct burners and one (1) 220 MW nominally rated steam turbine

Control Equipment: DLN combustors on the turbines; a selective catalytic reduction (SCR) system; and an oxidation catalyst

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

i. C-08-267 (Boiler)

Emissions from natural gas fired boilers include VOC, CO, NO_x, SO_x, and PM_{10} .

NO_x is the major pollutant of concern when burning natural gas. NO_x formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_x) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_x). Due to the low fuel nitrogen content of natural gas, nearly all NO_x emissions are thermal NO_x. Formation of thermal NO_x is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The boiler will control the formation of thermal NO_x with an ultra low NO_x burner. The District approved burner should reduce NO_x by premixing gaseous fuel and combustion air in a region near the burner exit, at a stoichiometry that minimizes prompt NO_x. This also eliminates the traditional NO_x versus CO tradeoff.

ii. C-08-268 (Diesel IC engine powering an electrical generator) and C-08-269 (Diesel IC engine powering a fire water pump)

The two proposed diesel fired emergency IC engines will be equipped with turbochargers, intercooler/aftercoolers, and will be fired on very low (0.0015% by weight sulfur maximum) sulfur diesel.

The turbochargers reduce the NO_x emission rates from engines by approximately 10% by increasing the efficiency and promoting more complete burning of fuel.

The intercooler/aftercoolers function in conjunction with the turbochargers to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_x. NO_x emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.0015% by weight sulfur maximum) diesel fuel reduces SO_x emissions by approximately 99% from standard diesel fuel.

iii. C-08-270 (Cooling Tower)

The 12-cell mechanical draft cooling tower will be equipped with drift eliminators and will be limited to 0.0005% drift loss and 9,000 ppm total dissolved solids.

iv. C-08-271 (Turbines)

Each CTG will be equipped with a DLN combustor and will exhaust into a SCR system with ammonia injection, and a CO catalyst. The use of DLN combustors and an SCR system with ammonia injection can achieve a NOx emission rate of 2.0 ppmvd @ 15% O_2. CO emissions of 3.0 ppmvd @ 15% O_2 are proposed with the use of an oxidation catalyst. The uses of DLN combustors and good combustion practices have been shown to achieve VOC emissions of 2.0 ppmvd @ 15% O_2.

Emissions from natural gas fired turbines include NO_x, CO, VOC, PM_{10}, and SO_x. NO_x is the major pollutant of concern when combusting natural gas. Virtually all gas turbines NO_x emissions originate as NO. This NO further oxidizes in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_x forms in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x) and 2) the conversion of nitrogen chemically bound in the fuel.

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion process disassociate and then react to form oxides of nitrogen. Prompt NO_x, a form of thermal NO_x, is formed in the area of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NOx. Prompt NOx is formed in both fuel rich flame zones and DLN combustion zones. The contribution of prompt NO_x to overall NO_x emissions is fairly small in conventional near-stoichemetric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_x emissions in DNL combustors. For this reason prompt NO_x becomes an important consideration for DLN combustor designs, and establishes a minimum NOx level attainable in lean mixtures.

Fuel NO_x is formed when fuels containing nitrogen are burned. Molecular nitrogen present as N_2 in some natural gas, does not contribute a significant amount to fuel NO_x formation. With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_x, fuel NO_x is not a major contributor to overall NO_x emissions from gas turbines firing natural gas.

The level of NO_x emissions for each turbine is design and mode of operation dependent. The primary NOx emission determinants are the combustor design, types of fuel burned, ambient conditions, operating cycles, and the power output of the turbine.

The most important factor in the formation of NO_x is the design of the combustor, with the parameters controlling air/fuel ratio and the introduction of cooling air being key to thermal NO_x formation. Thermal NO_x formation is mostly a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_x formation. Simultaneous mixing and combustion results in localized fuel rich zones that yield high flame temperatures in which substantial thermal NO_x production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature and therefore results in reduced thermal NO_x formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_x formation during combustion. This is known as DLN combustion.

SCR systems selectively reduce NO_x emissions by injecting ammonia (NH_3) into the exhaust gas stream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90% NO_x reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750°F. Exhaust gas temperatures greater than the upper limit (750°) will cause NO_x and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% 0_2.

CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_x formation can result in increased CO emissions.

Post combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert CO to carbon dioxide (CO_2).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emission by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

The lube oil coalesce will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

VII. GENERAL CALCULATIONS:

A. Assumptions

i. C-08-267 (Boiler)

- External O_2 stack gas concentration is 3%.
- Natural gas F factor is 8,710 dscf/MMBtu (Ref. 40 CFR Part 60, Appendix A, Method 19).
- Heating value of natural gas is 1,033 Btu/scf (per applicant).
- The applicant is proposing a maximum natural gas usage rate of 37.0 MMBtu/hr.
- Maximum daily and annual emissions for all pollutants are estimated assuming ten (10) hours per day and 3,850 hours per year operating at full load.

ii. C-08-268 (Diesel IC engine powering electrical generator) and C-08-269 (Diesel IC engine powering a fire water pump)

- Density of diesel is 7.1 lb/gal.
- BTU content of diesel is 19,300 Btu/lb.
- Emissions are based on 24 hours per day (maximum emergency use) and 200 hours per year of operation (includes emergency use and a maximum 50 hours for maintenance and testing).

iii. C-08-270 (Cooling Tower)

- Cooling water TDS content is 9000 ppm
- Drift limited to less than 0.0005%
- Density of water is 8.33 lb/gal
- Emissions are based on full operation, 24 hours per day and 365 days per year

v. C-08-271 (Turbines)

- Heating value of natural gas is 1,033 Btu/scf (per applicant).
- The commissioning period will not exceed 415 operating hours per CTG and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.
- Maximum daily emissions for each CTG for VOC, CO, and NO_X are estimated assuming six (6) hours operating in startup and shutdown mode and eighteen (18) hours operating while firing at full load with operation of the duct burner.
- Maximum daily emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming twenty-four (24) hours operating while firing at full load with the operation of the duct burner.
- Maximum annual emissions for each CTG for VOC, SOx, PM_{10}, and NH_3 are estimated assuming the CTG is operated according to a full annual scenario. The full annual scenario results in CTG operation of zero hours operating in

startup and shutdown mode, 3,454 hours operating while firing at full load with the duct burner, and 5,306 hours operating while firing at full load without the duct burner.

- Maximum annual emissions for each CTG for CO and NOx are estimated assuming the CTG is operated according to a daily cycling scenario. The daily cycling scenario results in CTG operation of 365 (1.0 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 3,317 hours operating while firing at full load with the duct burner, and 3,317 hours operating while firing at full load without the duct burner.
- Each emission calculation uses the worst case of the two proposed turbines. The Siemens turbine results were used for all pollutants, since it has the worst case emissions for all pollutants.

B. Emission Factors

i. C-08-267 (Boiler)

For the new boiler, the emissions factors for are provided by the applicant.

Boiler Emission Factors*		
Pollutant	ppmv @ 3%O_2	lb/MMBtu
VOC	10.0	0.00436
CO	50.0	0.038
NOx	9.0	0.011
SO_X	--	0.0014
PM_{10}	--	0.0075

*Note: lb/MMBtu equivalent of ppmv values @ 3% O_2 as provided by the Applicant

ii. C-08-268 (Diesel IC engine powering electrical generator)

For the new emergency diesel-fired IC engine powering an electrical generator, the emissions factors for VOC, CO, NO_X, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

Diesel-fired IC Engine Emission Factors		
	g/hp·hr	Source
VOC	0.01	Engine Manufacturer
CO	0.19	Engine Manufacturer
NO_x	4.82	Engine Manufacturer
**SO_x	0.0055	Mass Balance Equation Below
PM_{10}	0.02	Engine Manufacturer

**SO_X is calculated as follows:

$$0.0015\%\,sulfur \times \frac{0.00809\,lbSOx}{hp \cdot hr} \times \frac{453.6\,g}{lb} = 0.005\,\frac{g\,SOx}{hp \cdot hr}$$

iii. C-08-269 (Diesel IC engine powering fire water pump)

For the new emergency diesel-fired IC engine powering a fire water pump, the emissions factors for VOC, CO, NO_X, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

Diesel-fired IC Engine Emission Factors		
	g/hp·hr	Source
VOC	0.06	Engine Manufacturer
CO	0.45	Engine Manufacturer
NO_x	2.69	Engine Manufacturer
*SO_x	0.0055	Engine Manufacturer
PM_{10}	0.055	Engine Manufacturer

$$^{*}\,0.0015\%\,sulfur \times \frac{0.00809\,lbSOx}{hp \cdot hr} \times \frac{453.6\,g}{lb} = 0.005\,\frac{g\,SOx}{hp \cdot hr}$$

iv. C-08-270 (Cooling Tower)

For the new 12-cell, mechanical draft cooling tower, the emission factor for PM_{10} was provided by the applicant and is based on the total dissolved solids content of the cooling water (TDS = 9000 ppm), as provided by the wastewater plant that is supplying the cooling water, and the proposed drift rate (0.0005%) and is calculated as follows:

$$\frac{8.33lb}{gallon} \times \frac{9000ppm}{1{,}000{,}000} \times 0.0005\% \times 1{,}000{,}000 = 0.3748\ lb/million\ gallons$$

The District has assumed that 100% of the Pm emitted by the cooling tower is PM10.

v. C-08-271 (Turbines)

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

Commissioning Period Emissions					
	VOC	CO	NO_x	SO_x	PM_{10}
Mass Emission Rate (per turbine, lb/hr)	163.8	3812.6	140	7.13	12.8

The maximum and average air contaminant mass emission rates (lb/hr) during the start-up and shutdown period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

Startup and Shutdown Emissions					
	VOC	CO	NO_x	SO_X	PM_{10}
Maximum Mass Emission Rate (per turbine, lb/hr)	16	500	140	5.27	7.50
Average Mass Emission Rate (per turbine, lb/hr)	16	250	100	1.32	7.50

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% O_2), and startup and shutdown emissions rates (lb/hr) provided by the applicant (see Attachment C) for the proposed CTGs are summarized below.

The emission rates from the turbines and duct burners are calculated below:

Maximum Emission Rate Without Duct Burner Firing:

The worst-case VOC, CO, NO_X, PM_{10} and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 26.2 °F. The worst-case SO_X mass emission rate, from either turbine, will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG without the duct burner firing:

Emission Rate (lb/hr) = ppm x [(20.95 – EO%) / (20.95 – O_2%)] x MW x (2.60×10^{-3}) x flow x (60 min/1 hour)

Where:

ppm is the emission concentration in ppmvd @ 15% O_2 (VOC = 2 ppmv, CO = 3 ppmv, NOx = 2 ppmv, NH3 = 5 ppmv)

EO is the exhaust gas concentration to which the emission concentrations are corrected: (13.51%)

O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)
MW is the molecular weight of the pollutant: (MW_{voc} = 16 lb/lb-mol, MW_{CO} = 28 lb/lb-mol, MW_{NOx} = 46 lb/lb-mol, MW_{NH3} = 17 lb/lb-mol)
2.60×10^{-3} is one over the molar specific volume (lb-mol/scf)
Flow is the dry standard exhaust flow rate, corrected for temperature and moisture (885,155 dscf/min)

VOC Emission Rate (lb/hr) = $(2\text{x}10^{-6})$ x [(20.95 – 13.51) / (20.95 – 15.0)] x 16 x (2.60×10^{-3}) x 885,155 x 60 = **5.52 lb-VOC/hr**

CO Emission Rate (lb/hr) = $(3\text{x}10^{-6})$ x [(20.95 – 13.51) / (20.95 – 15.0)] x 28 x (2.60×10^{-3}) x 885,155 x 60 = **14.49 lb-CO/hr**

NO_X Emission Rate (lb/hr) = $(2\text{x}10^{-6})$ x [(20.95 – 13.51) / (20.95 – 15.0)] x 46 x (2.60×10^{-3}) x 885,155 x 60 = **15.87 lb-NO_X/hr**

NH_3 Emission Rate (lb/hr) = $(5\text{x}10^{-6})$ x [(20.95 – 13.51) / (20.95 – 15.0)] x 17 x (2.60×10^{-3}) x 885,155 x 60 = **14.66 lb-NH_3/hr**

For SO_X and PM_{10}, the following calculation will be used to calculate the emission rate of the CTG without the duct burner firing:
Emission Rate (lb/hr) = CTG Max Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

PM_{10} Emission Rate (lb/hr) = (2183 MMBtu/hr) x (0.0034 lb-PM_{10}/MMBtu)
= **7.5 lb-PM_{10}/hr**

SO_X Emission Rate (lb/hr) = (2183 MMBtu/hr) x (0.00277 lb-SO_X/MMBtu)
= **6.04 lb-SO_X/hr**

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Maximum Emission Rates and Concentrations Without Duct Burner Firing (@ 100% Load & 26.2 °F)						
	VOC	CO	NO_x	SO_X	PM_{10}	NH_3
Mass Emission Rates (per turbine, lb/hr)	5.52	14.49	15.87	6.04	7.50	14.66
ppmvd @ 15% O_2 limits	2.0	3.0	2.0	--	--	5.0
lb/MMBtu*	0.0013	0.0066	0.0073	0.0028	0.0034	--

* Emission factors were taken from Table 5.1A-2 B in the ATC application submittal.

Maximum Emission Rate With Duct Burner Firing:

The worst-case VOC, CO, NO_X, PM_{10} and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 59 °F. The worst-case SO_X mass emission rate, from either turbine, will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG with the duct burner firing:

Emission Rate (lb/hr) = ppm x [(20.95 – EO%) / (20.95 – O_2%)] x MW x (2.60×10^{-3}) x flow x (60 min/1 hour)

Where:

ppm is the emission concentration in ppmvd @ 15% O_2 (VOC = 2 ppmv, CO = 3 ppmv, NOx = 2 ppmv, NH3 = 5 ppmv)

O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

EO is the exhaust gas concentration to which the emission concentrations are corrected: (11.93%)

MW is the molecular weight of the pollutant: (MW_{voc} = 16 lb/lb-mol, MW_{CO} = 28 lb/lb-mol, MW_{NOx} = 46 lb/lb-mol, MW_{NH3} = 17 lb/lb-mol)

2.60 x 10^{-3} is one over the molar specific volume (lb-mol/scf)

Flow is the dry standard exhaust flow rate, corrected for temperature and moisture (862,687 dscf/min)

VOC Emission Rate (lb/hr) = $(2\times10^{-6}) \times [(20.95 - 11.93) / (20.95 - 15.0)] \times 16 \times (2.60\times10^{-3}) \times 862{,}687 \times 60$ = **6.52 lb-VOC/hr**

CO Emission Rate (lb/hr) = $(3\times10^{-6}) \times [(20.95 - 11.93) / (20.95 - 15.0)] \times 28 \times (2.60\times10^{-3})\ 862{,}687 \times 60$ = **17.12 lb-CO/hr**

NO_X Emission Rate (lb/hr) = $(2\times10^{-6}) \times [(20.95 - 11.93) / (20.95 - 15.0)] \times 46 \times (2.60\times10^{-3}) \times 862{,}687 \times 60$ = **18.75 lb-NO_X/hr**

For SO_X and PM_{10}, the following calculation will be used to calculate the emission rate of the CTG with the duct burner firing:
Emission Rate (lb/hr) = [CTG Max Heat Input + Duct Burner Max Heat Input] (MMBtu/hr) x Emission Factor (lb/MMBtu)

SO_X Emission Rate (lb/hr) = (2,579 MMBtu/hr) x (0.00277 lb-SO_X/MMBtu)
= **7.13 lb-SO_X/hr**

PM_{10} Emission Rate (lb/hr) = (2,579 MMBtu/hr) x (0.0035 lb-PM_{10}/MMBtu)
= **9.00 lb-PM_{10}/hr**

NH_3 Emission Rate (lb/hr) = $(5\times10^{-6}) \times [(20.95 - 11.93) / (20.95 - 15.0)] \times 17 \times (2.60\times10^{-3}) \times 862{,}687 \times 60$ = **17.32 lb-NH_3/hr**

Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 59 °F)						
	VOC	CO	NO_x	SO_X	PM_{10}	NH_3
Mass Emission Rates (per turbine, lb/hr)	6.52	17.12	18.75	7.13	9.00	17.32
ppmvd @ 15% O_2 limits	2.0	3.0	2.0	--	--	5.0
lb/MMBtu*	0.0013	0.0066	0.0073	0.00277	0.0034	--

* Emission factors were taken from Table 5.1A-2 in the ATC application submittal.

C. Calculations

1. Pre-Project Potential to Emit (PTE)

Section 228 of Rule 3.4 defines the potential to emit as the maximum physical and operational design capacity to emit a pollutant. This can take into account emission control devices and limitations on hours of operation if the limitations are incorporated into the permits. Since this is a brand new facility, the pre-project potential to emit for all the emissions units associated with this project is equal to zero.

2. Proposed Emissions:

i. C-08-267 (Boiler)

The potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{VOC} = *(0.00422 lb/MMBtu) ∗ (37.0 MMBtu/hr)*
= ***0.16 lb VOC/hr***

= *(0.00422 lb/MMBtu) ∗ (37.0 MMBtu/hr) ∗ (10 hr/day)*
= ***1.6 lb VOC/day***

= *(0.00422 lb/MMBtu) *(37.0 MMBtu/hr) ∗ (900 hr/1st qtr)*
= ***139 lb VOC/qtr***

= *(0.00422 lb/MMBtu) *(37.0 MMBtu/hr) ∗ (910 hr/2nd qtr)*
= ***141 lb VOC/qtr***

= *(0.00422 lb/MMBtu) *(37.0 MMBtu/hr) ∗ (920 hr/3rd qtr)*
= ***142 lb VOC/qtr***

= *(0.00422 lb/MMBtu) *(37.0 MMBtu/hr) ∗ (920 hr/4th qtr)*
= ***142 lb VOC/qtr***

= *(0.00422 lb/MMBtu) ∗ (37.0 MMBtu/hr) ∗ (3,650 hr/year)*
= ***570 lb VOC/year***

PE_{CO} = *(0.03691 lb/MMBtu) ∗ (37.0 MMBtu/hr)*
= ***1.37 lb CO/hr***

$= (0.03691 \text{ lb/MMBtu}) * (37.0 \text{ MMBtu/hr}) * (10 \text{ hr/day})$
$=$ ***13.7 lb CO/day***

$= (0.03691 \text{ lb/MMBtu}) * (37.0 \text{ MMbtu/hr}) * (900 \text{ hr/1}^{st}\text{qtr})$
$=$ ***1,217 lb CO/qtr***

$= (0.03691 \text{ lb/MMBtu}) * (37.0 \text{ MMbtu/hr}) * (910 \text{ hr/2ndqtr})$
$=$ ***1,232 lb CO/qtr***

$= (0.03691 \text{ lb/MMBtu}) * (37.0 \text{ MMbtu/hr}) * (920 \text{ hr/3rdqtr})$
$=$ ***1,243 lb CO/qtr***

$= (0.03691 \text{ lb/MMBtu}) * (37.0 \text{ MMbtu/hr}) * (920 \text{ hr/3rdqtr})$
$=$ ***1,243 lb CO/qtr***

$= (0.03691 \text{ lb/MMBtu}) * (37.0 \text{ MMBtu/hr}) * (3{,}650 \text{ hr/year})$
$=$ ***4,985 lb CO/year***

$PE_{NOx} = (0.01091 \text{ lb/MMBtu}) * (37.0 \text{ MMBtu/hr})$
$=$ ***0.4 lb NO_X/hr***

$= (0.01091 \text{ lb/MMBtu}) * (37.0 \text{ MMBtu/hr}) * (10 \text{ hr/day})$
$=$ ***4.0 lb NO_X/day***

$= (0.01091 \text{ lb } NO_X\text{/MMBtu}) * (37.0 \text{ MMBtu/hr}) * (900 \text{ hrs/1st qtr})$
$=$ ***360 lb NO_X/qtr***

$= (0.01091 \text{ lb } NO_X\text{/MMBtu}) * (37.0 \text{ MMBtu/hr}) * (910 \text{ hrs/2nd qtr})$
$=$ ***364 lb NO_X/qtr***

$= (0.01091 \text{ lb } NO_X\text{/MMBtu}) * (37.0 \text{ MMBtu/hr}) * (920 \text{ hrs/3rd qtr})$
$=$ ***368 lb NO_X/qtr***

$= (0.01091 \text{ lb } NO_X\text{/MMBtu}) * (37.0 \text{ MMBtu/hr}) * (920 \text{ hrs/1st qtr})$
$=$ ***368 lb NO_X/qtr***

$= (0.01091 \text{ lb/MMBtu}) * (37.0 \text{ MMBtu/hr}) * (3{,}650 \text{ hr/year})$
$=$ ***1,474 lb NO_X/year***

$PE_{SOx} = (0.0014 \text{ lb/MMBtu}) * (37.0 \text{ MMBtu/hr})$

= ***0.05 lb SO_X/hr***

= *(0.0014 lb/MMBtu) ∗ (37.0 MMBtu/hr) ∗ (10 hr/day)*
= ***0.5 lb SO_X/day***

= *(0.0014 lb/MMBtu) *(37.0 MMBtu/hr) ∗ (900 hr/1^{st} qtr)*
= ***46 lb SO_X/qtr***

= *(0.0014 lb/MMBtu) *(37.0 MMBtu/hr) ∗ (910 hr/2nd qtr)*
= ***47 lb SO_X/qtr***

= *(0.0014 lb/MMBtu) *(37.0 MMBtu/hr) ∗ (920 hr/3rd qtr)*
= ***47 lb SO_X/qtr***

= *(0.0014 lb/MMBtu) *(37.0 MMBtu/hr) ∗ (920 hr/4th qtr)*
= ***47 lb SO_X/qtr***

= *(0.0014 lb/MMBtu) ∗ (37.0 MMBtu/hr) ∗ (3,650 hr/year)*
= ***189 lb SO_X/year***

PE_{PM10} = *(0.0075 lb/MMBtu) ∗ (37.0 MMBtu/hr)*
= ***0.28 lb PM_{10}/hr***

= *(0.0075 lb/MMBtu) ∗ (37.0 MMBtu/hr) ∗ (10 hr/day)*
= ***2.8 lb PM_{10}/day***

= *(0.0075 lb/MMBtu) *(37.0 MMbtu/hr) ∗ (900 hr/1^{st} qtr)*
= ***247 lb PM_{10}/qtr***

= *(0.0075 lb/MMBtu) *(37.0 MMbtu/hr) ∗ (910 hr/2^{nd} qtr)*
= ***250 lb PM_{10}/qtr***

= *(0.0075 lb/MMBtu) *(37.0 MMbtu/hr) ∗ (920 hr/3^{rd} qtr)*
= ***253 lb PM_{10}/qtr***

= *(0.0075 lb/MMBtu) *(37.0 MMbtu/hr) ∗ (920 hr/4th qtr)*
= ***253 lb PM_{10}/qtr***

= *(0.0075 lb/MMBtu) ∗ (37.0 MMBtu/hr) ∗ (3,650 hr/year)*
= ***1013 lb PM_{10}/year***

Maximum Boiler Potential to Emit (C-08-267)						
Pollutant	Daily (lb)	Qtr #1 (lb)	Qtr #2 (lb)	Qtr #3 (lb)	Qtr #4 (lb)	Year (lb)
VOC	1.6	139	141	142	142	570
CO	13.7	1,217	1,232	1,243	1,243	4,985
NO_x	4.0	360	364	368	368	1,474
SO_x	0.5	46	47	47	47	189
PM_{10}	2.8	247	250	253	253	1,013

ii. C-08-268 (Diesel IC engine powering electrical generator)

The emissions for the emergency IC engine are calculated as follows, and summarized in the table below:

PE_{VOC} = *(0.01 g/hp·hr) ∗ (1,500 hp) ÷ (453.6 g/lb)*
= ***0.03 lb VOC/hr***

= *(0.01 g/hp·hr) ∗ (1,500 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)*
= ***0.8 lb VOC/day***

= *(0.01 g/hp·hr) ∗ (1,500 hp) ÷ (453.6 g/lb) ∗ (200 hr/qtr)*
= ***7 lb VOC/qtr***

= *(0.01 g/hp·hr) ∗ (1,500 hp) ÷ (453.6 g/lb) ∗ (200 hr/year)*
= ***7 lb VOC/year***

PE_{CO} = *(0.19 g/hp·hr) ∗ (1,500 hp) ÷ (453.6 g/lb)*
= ***0.63 lb CO/hr***

= *(0.19 g/hp·hr) ∗ (1,500 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)*
= ***15.1 lb CO/day***

= *(0.19 g/hp·hr) ∗ (1,500 hp) ÷ (453.6 g/lb) ∗ (200 hr/qtr)*
= ***126 lb CO/qtr***

= *(0.19 g/hp·hr) ∗ (1,500 hp) ÷ (453.6 g/lb) ∗ (200 hr/year)*
= ***126 lb CO/year***

$$PE_{NOx} = (4.82\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb)$$
$$= \mathbf{15.9\ lb\ NO_X/hr}$$

$$= (4.82\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (24\ hr/day)$$
$$= \mathbf{382.5\ lb\ NO_X/day}$$

$$= (4.82\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (200\ hr/qtr)$$
$$= \mathbf{3{,}188\ lb\ NO_X/qtr}$$

$$= (4.82\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (200\ hr/year)$$
$$= \mathbf{3{,}188\ lb\ NO_X/year}$$

$$PE_{SOx} = (0.0055\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb)$$
$$= \mathbf{0.02\ lb\ SO_X/hr}$$

$$= (0.0055\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (24\ hr/day)$$
$$= \mathbf{0.4\ lb\ SO_X/day}$$

$$= (0.0055\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (200\ hr/qtr)$$
$$= \mathbf{4\ lb\ SO_X/qtr}$$

$$= (0.0055\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (200\ hr/year)$$
$$= \mathbf{4\ lb\ SO_X/year}$$

$$PE_{PM10} = (0.02\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb)$$
$$= \mathbf{0.1\ lb\ PM_{10}/hr}$$

$$= (0.02\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (24\ hr/day)$$
$$= \mathbf{1.8\ lb\ PM_{10}/day}$$

$$= (0.02\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (200\ hr/qtr)$$
$$= \mathbf{15\ lb\ PM_{10}/qtr}$$

$$= (0.02\ g/hp\cdot hr) * (1{,}500\ hp) \div (453.6\ g/lb) * (200\ hr/year)$$
$$= \mathbf{15\ lb\ PM_{10}/year}$$

Maximum Emergency Engine Potential to Emit (C-08-268)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
VOC	0.03	0.8	7	7
CO	0.63	15.1	126	126
NO_x	15.94	382.5	3,188	3,188
SO_X	0.02	0.4	4	4
PM_{10}	0.1	1.8	15	15

iii. C-08-269 (Diesel IC engine powering fire water pump)
The emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{VOC} = *(0.06 g/hp·hr) ∗ (315 hp) ÷ (453.6 g/lb)*
= ***0.04 lb VOC/hr***

= *(0.06 g/hp·hr) ∗ (315 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)*
= ***1.0 lb VOC/day***

= *(0.06 g/hp·hr) ∗ (315 hp) ÷ (453.6 g/lb) ∗ 200 hr/qtr)*
= ***8 lb VOC/qtr***

= *(0.06 g/hp·hr) ∗ (315 hp) ÷ (453.6 g/lb) ∗ (200 hr/year)*
= ***8 lb VOC/year***

PE_{CO} = *(0.45 g/hp·hr) ∗ (315 hp) ÷ (453.6 g/lb)*
= ***0.31 lb CO/hr***

= *(0.45 g/hp·hr) ∗ (315 hp) ÷ (453.6 g/lb ∗ (24 hr/day)*
= ***7.5 lb CO/day***

= *(0.45 g/hp·hr) ∗ (315 hp) ÷ (453.6 g/lb) ∗ (200 hr/qtr)*
= ***63 lb CO/qtr***

$$= (0.45\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (200\ hr/year)$$
$$= \mathbf{63\ lb\ CO/year}$$

$$PE_{NOx} = (2.69\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb)$$
$$= \mathbf{1.87\ lb\ NO_X/hr}$$

$$= (2.69\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (24\ hr/day)$$
$$= \mathbf{44.8\ lb\ NO_X/day}$$

$$= (2.69\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (200\ hr/qtr)$$
$$= \mathbf{374\ lb\ NO_X/qtr}$$

$$= (2.69\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (200\ hr/year)$$
$$= \mathbf{374\ lb\ NO_X/year}$$

$$PE_{SOx} = (0.005\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb)$$
$$= \mathbf{Neg.\ lb\ SO_X/hr}$$

$$= (0.005\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (24\ hr/day)$$
$$= \mathbf{0.1\ lb\ SO_X/day}$$

$$= (0.005\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (200\ hr/qtr)$$
$$= \mathbf{1\ lb\ SO_X/qtr}$$

$$= (0.005\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (200\ hr/year)$$
$$= \mathbf{1\ lb\ SO_X/year}$$

$$PE_{PM10} = (0.055\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb)$$
$$= \mathbf{0.04\ lb\ PM_{10}/hr}$$

$$= (0.055\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (24\ hr/day)$$
$$= \mathbf{0.9\ lb\ PM_{10}/day}$$

$$= (0.055\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (200\ hr/qtr)$$
$$= \mathbf{8\ lb\ PM_{10}/qtr}$$

$$= (0.055\ g/hp\cdot hr) * (315\ hp) \div (453.6\ g/lb) * (200\ hr/year)$$
$$= \mathbf{8\ lb\ PM_{10}/year}$$

Maximum Fire Pump Engine Potential to Emit (C-08-269)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
VOC	0.04	1.0	8	8
CO	0.31	7.5	63	63
NO_X	1.87	44.8	374	374
SO_X	Neg.	0.1	1	1
PM_{10}	0.04	0.9	8	8

iv. C-08-270 (Cooling Tower)

The emissions for the cooling tower are calculated as follows, and summarized in the Table below:

PE_{PM10} = *(0.3749 lb/million gallons) * (8.5 million gallons/hr)*
= ***3.19 lb PM_{10}/hr***

= *(0.3749 lb/million gallon) * (204.5 million gallons/day)*
= ***76.6 lb PM_{10}/day***

= *(0.3749 lb/million gallon) * (18,403 million gallons/1st qtr)*
= ***6,898 lb PM_{10}/1st qtr***

= *(0.3749 lb/million gallon) * (18,608 million gallons/2nd qtr)*
= ***6,975 lb PM_{10}/2nd qtr***

= *(0.3749 lb/million gallon) * (18,812 million gallons/3rd qtr)*
= ***7,052 lb PM_{10}/3rd qtr***

= *(0.3749 lb/million gallon) * (18,812 million gallons/4th qtr)*
= ***7,052 lb PM_{10}/4th qtr***

= *(0.3749) ∗ (74,635 million gallons/year)*
= ***27,977 lb PM_{10}/year***

Maximum Cooling Tower Potential to Emit (C-08-270)							
Pollutant	lb/hr	lb/day	lb/1st qtr	lb/2nd qtr	lb/3rd qtr	lb/4th qtr	lb/year
PM_{10}	3.19	76.6	6,898	6,975	7,052	7,052	27,977

v. C-08-271 (Turbines)

a. Maximum Hourly PTE

The maximum hourly potential to emit for VOC, CO, and NO_X from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PTE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 280 lbs/hr [maximum startup emission rate (140 lbs/hr) x number of turbines (2)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,000 lbs/hr, [maximum startup emission rate (500 lbs/hr) x number of turbines (2)].

The maximum hourly emissions are summarized in the table below:

Maximum Turbine Hourly Potential to Emit (lb/hr)				
	Maximum Startup/Shutdown Emissions (per turbine)	Turbine w/ Duct Burner Emissions (per turbine)	Turbine w/out Duct Burner Emissions (per Turbine)	Maximum Hourly Emissions for Both Turbines
VOC	16	6.52	5.52	32.00
CO	500	17.12	14.49	1,000.00
NO_x	140	18.75	15.87	280.00
SO_X	5.27	7.13	6.04	14.26
PM_{10}	7.50	9.0	7.50	18.0
NH_3	12.78	17.32	14.66	34.64

b. Maximum Daily Potential to Emit

Maximum daily emissions for VOC, CO, and NO_X, occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for SO_X, PM_{10}, and NH_3 will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for SO_X, PM_{10}, and NH_3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Turbine Daily Potential to Emit (w/ Startup and Shutdown)				
	Maximum Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (59° F)	Emissions Rate @ 100% Load without duct burner (26° F)	Daily Emission Limit (total for both turbines)
VOC	16 lb/hr	6.52 lb/hr	5.52 lb/hr	426.8 lb/day
CO	500 lb/hr (max)	17.12 lb/hr	14.49 lb/hr	6,616.3 lb/day
NO_x	140 lb/hr (max)	18,75 lb/hr	15,87 lb/hr	2,355.0 lb/day
SO_x	5.27lb/hr (max)	7.13 lb/hr	6.04 lb/hr	342.4 lb/day
PM_{10}	7.50 lb/hr	9.0 lb/hr	7.50 lb/hr	432.0 lb/day
NH_3	12.78 lb/hr	17.32 lb/hr	14.66 lb/hr	831.6 lb/day

c. Maximum Annual Potential to Emit

Consistent with the applicant proposal, maximum facility emissions were calculated for four basic operating cases: daily cycling, weekly cycling, base load, and full annual. The SO_X emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.25 gr/100 dscf.

SO_X EF = (0.25 gr S/100 dscf) x (1 lb S/7000 gr) x (64 lb SO_X/32 lb S) x (1 scf/1033 Btu) x (10^6 Btu/MMBtu)
= 0.00069 lb-SO_X/MMBtu

CTG w/o Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (2183 MMBtu/hr) x (0.00069 lb-SO_X/MMBtu)
= **1.51 lb-SO_X/hr**

CTG w/ Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (2579 MMBtu/hr) x (0.00069 lb-SO_X/MMBtu)
= 1.78 lb-SO_X/hr

Potential annual emissions for each pollutant will be calculated for each of the four scenarios in the tables below:

Scenario 1) Daily Cycling:

Both turbines with the same operating schedule: 365 (1.0 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 3,317 hours operating while firing at full load with the duct burner, 3,317 hours operating while firing at full load without the duct burner, and 1,761 hours of downtime. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than or equal to the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner.

Annual Potential to Emit Scenario 1) Daily Cycling*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (59° F)	Emissions Rate @ 100% Load without duct burner (26° F)	Annual Potential to Emit (total for both turbines)
VOC	16 lb/hr (avg)	6.52 lb/hr	5.52 lb/hr	45.78 ton/year
CO	250 lb/hr (avg)	17.12 lb/hr	14.49 lb/hr	**194.18 ton/year**
NO_x	100 lb/hr (avg)	18.75 lb/hr	15.87 lb/hr	**151.34 ton/year**
SO_X	1.32 lb/hr	1.78 lb/hr	1.51 lb/hr	11.40 ton/year
PM_{10}	7.50 lb/hr	9.0 lb/hr	7.50 lb/hr	57.47 ton/year
NH_3	12.78 lb/hr	17.32 lb/hr	14.66 lb/hr	110.76 ton/year

* Emission factors were taken from Table 5.1A-2 B in the ATC application submittal.

Scenario 2) Weekly Cycling:

Turbine #1: 156 (3 hr/cold start x 52 cold start/yr) hours operating in startup and shutdown mode, 3,500 hours operating while firing at full load with the duct burner, 1,360 hours operating while firing at full load without the duct burner, and 3,744 hours of down time.

Turbine #2: 365 (1.0 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 3,500 hours operating while firing at full load with the duct burner, 3,435 hours operating while firing at full load without the duct burner, and 1,460 hours of down time.

Annual Potential to Emit Scenario 2) Weekly Cycling*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (59° F)	Emissions Rate @ 100% Load without duct burner (26° F)	Annual Potential to Emit (total for both turbines)
VOC	16 lb/hr (avg)	6.52 lb/hr	5.52 lb/hr	40.23 ton/year
CO	250 lb/hr (avg)	17.12 lb/hr	14.49 lb/hr	159.78 ton/year
NO_x	100 lb/hr (avg)	18.75 lb/hr	15.87 lb/hr	129.72 ton/year
SO_X	1.32 lb/hr (avg)	1.78 lb/hr	1.51 lb/hr	10.20 ton/year
PM_{10}	7.50 lb/hr	9.00 lb/hr	7.50 lb/hr	51.44 ton/year
NH_3	12.78 lb/hr	17.32 lb/hr	14.66 lb/hr	99.12 ton/year

* Emission factors were taken from Table 5.1A-2 B in the ATC application submittal.

Scenario 3) Baseload:

Turbine #1: 36 (3 hr/cold start x 12 cold start/yr) hours operating in startup and shutdown mode, 3,500 hours operating while firing at full load with the duct burner, 4,360 hours operating while firing at full load without the duct burner, and 864 hours of down time.

Turbine #2: 12 (1 hr/hot start x 12 hot start/yr) hours operating in startup and shutdown mode, 3,500 hours operating while firing at full load with the duct burner, 4,360 hours operating while firing at full load without the duct burner, and 888 hours of down time.

Annual Potential to Emit Scenario 3) Baseload *				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (59° F)	Emissions Rate @ 100% Load without duct burner (26° F)	Annual Potential to Emit (total for both turbines)
VOC	16 lb/hr (avg)	6.52 lb/hr	5.52 lb/hr	47.28 ton/year
CO	250 lb/hr (avg)	17.12 lb/hr	14.49 lb/hr	129.09 ton/year
NO_x	100 lb/hr (avg)	18.75 lb/hr	15.87 lb/hr	137.22 ton/year
SO_X	1.32 lb/hr (avg)	1.78 lb/hr	1.51 lb/hr	12.85 ton/year
PM_{10}	7.50	9.0 lb/hr	7.50 lb/hr	64.38 ton/year

Annual Potential to Emit Scenario 3) Baseload *				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (59° F)	Emissions Rate @ 100% Load without duct burner (26° F)	Annual Potential to Emit (total for both turbines)
NH_3	12.78	17.32 lb/hr	14.66 lb/hr	124.87 ton/year

* Emission factors were taken from Table 5.1 A-2 B in the ATC application submittal.

Scenario 4) Full Annual:

Both turbines with the same operating schedule: 3,454 hours operating while firing at full load with the duct burner and 5,306 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner.

Annual Potential to Emit Scenario 4) Full Annual*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (59° F)	Emissions Rate @ 100% Load without duct burner (26° F)	Annual Potential to Emit (total for both turbines)
VOC	16 lb/hr (avg)	6.52 lb/hr	5.52 lb/hr	**51.81 ton/year**
CO	250 lb/hr (avg)	17.12 lb/hr	14.49 lb/hr	136.01 ton/year

Annual Potential to Emit Scenario 4) Full Annual*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (59° F)	Emissions Rate @ 100% Load without duct burner (26° F)	Annual Potential to Emit (total for both turbines)
NO_x	100 lb/hr (avg)	18.75 lb/hr	15.87 lb/hr	148.97 ton/year
SO_X	N/A(8)	1.78 lb/hr	1.51 lb/hr	**14.17 ton/year**
PM_{10}		9.0 lb/hr	7.50 lb/hr	**70.89 ton/year**
NH_3	N/A	17.32 lb/hr	14.66 lb/hr	**137.63 ton/year**

* Emission factors were taken from Table 5.1A-2 B in the ATC application submittal.

Maximum Annual Potential to Emit:
The highest annual potential emissions, for each pollutant, from the four different scenarios will be taken to determine the maximum annual potential to emit for the CTGs. The results are summarized in the table below:

Maximum Turbine Annual Potential to Emit		
	Annual Potential to Emit (Total for both turbines)	Scenario
VOC	51.81 ton/year	Scenario 4

Maximum Turbine Annual Potential to Emit		
	Annual Potential to Emit (Total for both turbines)	Scenario
CO	194.18 ton/year	Scenario 1
NO_x	151.34 ton/year	Scenario 1
SO_X	14.17 ton/year	Scenario 4
PM_{10}	70.89 ton/year	Scenario 4
NH_3	137.63 ton/year	Scenario 4

d. Maximum Quarterly Potential to Emit

The applicant applied for lower second quarter operating hours because second quarter emission reduction credits are difficult to obtain in the YSAQMD District, therefore the facility will have a tighter production limit by permit condition, i.e. permitted fuel usage limit and permitted emission limit. Similar to the yearly maximum potential to emit shown in the section above, using the same assumptions and the same emission factors, the highest quarterly potential emissions, for each pollutant, from the four different scenarios was the proposed emissions from Scenario 1and 2 for CO and NOx, and Scenario 4 for VOC, SO_x, PM_{10}, and NH_3. Therefore the limits from these Scenarios will be taken to determine the maximum quarterly potential to emit for the CTGs. The results are summarized in the table below:

Maximum Quarterly Potential to Emit (lb/qtr)						
	VOC	CO	NO_x	SO_x	PM_{10}	NH_3
1^{st} Quarter	26,118	100,320	78,596	7,141	35,803	69,377

Maximum Quarterly Potential to Emit (lb/qtr)						
2nd Quarter	25,513	85,855	66,576	6,976	34,863	67,770
3rd Quarter	26,360	102,420	80,201	7,207	36,092	70,018
4th Quarter	25,642	99,769	77,297	7,010	35,014	68,101

3. Pre-Project Stationary Source Potential to Emit ($SSPTE_1$):

Section 228 of District Rule 3.4 defines potential to emit as "the maximum physical and operational design capacity to emit a pollutant." Since this is a new facility, there are no valid District issued Authority to Constructs (ATCs) or Permits to Operate (PTOs) at the stationary source, therefore the $SSPTE_1$ will be equal to zero.

4. Proposed Project Stationary Source Potential to Emit ($SSPTE_2$):

Pursuant to Section 231 of District Rule 3.4, the proposed emissions are the emissions based on the potential to emit for the new emissions units.

$SSPTE_2$ (lb/year)						
Permit Unit	VOC	CO	NO_x	SO_X	PM_{10}	NH_3
C-08-267	570	4,985	1,474	189	1,013	n/a
C-08-268	7	126	3,188	4	15	n/a
C-08-269	8	63	374	1	8	n/a
C-08-270	0	0	0	0	27,977	0
C-08-271	103,629	388,364	302,670	28,335	141,772	275,265

SSPTE$_2$ (lb/year)						
Permit Unit	VOC	CO	NO_X	SO_X	PM_{10}	NH_3
Total Facility Potential to Emit	**104,214**	**393,538**	**307,706**	**28,529**	**170,785**	**275,265**

5. Major Source Determination:

Pursuant to Section 222 of District Rule 3.4, a major stationary source is a stationary source that emits or has the potential to emit an affected pollutant in quantities equal to or exceeding any of the following thresholds:

Major Source Determination					
	VOC (lb/yr)	CO (lb/yr)	NO_X (lb/yr)	SO_X (lb/yr)	PM_{10} (lb/yr)
SSPE$_2$	104,214	393,538	307,706	28,529	170,785
Major Source Threshold	50,000	200,000	50,000	200,000	200,000
Major Source?	Yes	Yes	Yes	No	No

6. Historic Potential Emissions:

The Historic Potential Emissions are emissions based on the potential to emit of the emissions units prior to modification. As shown above, this facility will be a major source for VOC, CO, and NO_X emissions after this project, however since the emission units in the proposed project are all new, there are no historic actual emissions or SSPTE$_1$. Therefore, the historic potential emissions for each pollutant equal zero.

7. Major Modification:

Major Modification as defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this is a new source, this project cannot be considered a Major Modification.

8. Federal Major Modification

Pursuant to Section 221 of District Rule 3.4 this project does not constitute a Federal Major Modification because as discussed above, the proposed project is not a Major Modification.

VIII. COMPLIANCE:

Rule 2.3 Ringelmann Chart

Pursuant to Rule 2.3, a person shall not discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 2 (or 40% opacity).

This rule requirement is superseded by District Rule 3.4 requirement which allows the District to tighten this limit on a case by case basis on new or modified emissions unit. The proposed units are equipped with the newest and most efficient combustion technology; therefore the following condition will be listed on the ATCs to ensure rule compliance:

> The Permit Holder shall not discharge into the atmosphere from any single source of emission whatsoever, any air contaminant for a period or periods aggregating more than three (3) minutes in any one (1) hour which is: a) As dark or darker in shade than No. 1 on the Ringelmann Chart; or b) Greater than 20% opacity. [District Rule 3.4]

Rule 2.5 Nuisance

The rule prohibits discharge of air contaminants which could cause injury, detriment, nuisance, or annoyance to the public.

An aggregated health risk screening assessment was performed for all of the proposed project equipment and is included as Attachment F. The facility wide acute and chronic hazard indices are well below 1.0 and the cancer risk for the proposed power plant is greater than one (1) in a million, but less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. Therefore, even though T-BACT may not be required on a per emissions unit basis, T-BACT is required for the facility. As such the permit will have conditions requiring the following:

Nuisance T-BACT Requirements		
Process	T-BACT	Permit Condition
Boiler (C-08-267)	Ultra low NO_x burner; 9.0 ppm @ 3% O_2	NOx (as NO2) emission concentrations from this unit shall not exceed 9.0 ppmvd @ 3% O2
Emergency IC engine (C-08-268)	Latest EPA Certified Tier IC engine	Equipment Description identifying the latest EPA Certified Tier
Emergency IC engine (C-08-269)	Latest EPA Certified Tier IC engine	Equipment Description identifying the latest EPA Certified Tier
Cooling Tower (C-08-270)	Prohibit use of chromium containing material	The Permit Holder shall not use or allow the use of chromium compounds in the treatment of cooling tower make-up water
Combined-cycle combustion turbine generators (C-08-271)	Dry low No_x combustors; 2.0 ppm @ 15% O_2. 5.0 ppm NH3 @ 15% O2.	NOx (as NO2) emission concentrations from this unit shall not exceed 2.0 ppmvd @ 15% O2 NH3 emission concentrations from this unit shall not exceed 5.0 ppm @15% O2.

Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore the following condition will be listed on the permits to ensure compliance with this rule:

- The Permit Holder shall not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public or which cause to have a natural tendency to cause injury or damage to business or property. [District Rule 2.5]

The following conditions will be listed on C-08-271 for the turbines to ensure compliance with this rule:

- The NH3 emissions shall not exceed 5 ppmvd @ 15% O2 over a 24 hour average. [District Rule 2.5]

- The NH3 emissions shall not exceed 831.6 lb/day, 69,377 lb/1st quarter, 67,770 lb/2nd quarter, 70,018 lb/3rd quarter, 68,101 lb/4th quarter, and 137.63 tons/year. [District Rule 2.5]

- The Permit Holder shall install and maintain an ammonia (NH_3) flow meter and injection pressure indicator for the NH_3 injection system. The equipment shall be accurate to plus or minus 5 percent and shall be calibrated once every twelve months. [District Rule 2.5]

- The NH_3 emission concentration (slip) shall be verified by the continuous recording of the NH_3 injection rate to the SCR control system. The equipment shall operate within the NH_3 injection range established during the most recent source test until re-established through another valid source test. [District Rule 2.5]

Rule 2.11 Particulate Matter

The rule prohibits the discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grains per dry standard cubic foot.

i. C-08-267 (Boiler)

Boiler input heat rating = 37 MMBtu/hr
F-Factor for natural gas = 8,710 dscf/MMBtu
PM_{10} Daily Emissions = 2.8 lb/day
Assume:

100% PM in exhaust is PM_{10}

$$PM\ Conc = 2.8\ lb\frac{PM10}{Day} \times \frac{Day}{24} hours \times 7{,}000\frac{grain}{lb\ PM10} \times \frac{hr}{37} MMBtu \times \frac{MMBtu}{8{,}710} dscf = 0.003\ gr/dscf$$

Therefore compliance with the rule requirement is expected and a permit condition will be listed on the permit as follows:

- Particulate matter emissions shall not exceed 0.003 gr/dscf in concentration. [District Rule 3.4]

ii. C-08-268 (Diesel emergency IC engine)

$$\frac{0.08\ lb\ PM10}{hr} \times \frac{7{,}000\ gr}{lb} \times \frac{hr}{60\ min} \times \frac{min}{2{,}797.1} = 0.003\ gr/dscf$$

Therefore compliance with the rule requirement is expected and a permit condition will be listed on the permit as follows:

- Particulate matter emissions shall not exceed 0.003 gr/dscf in concentration. [District Rule 3.4]

iii. C-08-269 (Diesel emergency fire pump IC engine)

$$\frac{0.04\ lb\ PM10}{hr} \times \frac{7{,}000\ gr}{lb} \times \frac{hr}{60\ min} \times \frac{min}{468.2} = 0.010\ gr/dscf$$

Therefore compliance with the rule requirement is expected and a permit condition will be listed on the permit as follows:

- Particulate matter emissions shall not exceed 0.010 gr/dscf in concentration. [District Rule 3.4]

v. C-08-271 (Turbines)

$$PM\ Conc.\left(\frac{gr}{scf}\right) = (PM\ emission\ rate) \times \left(\frac{7000gr}{lb}\right) \div exhaust\ gas\ flow$$

PM_{10} emission rate = 9.0 lb/hr. Assuming 100% of PM is PM_{10}.

Exhaust Gas Flow = 19,949,371 dscf/hr

$$PM\ Conc. = \left(9.0\frac{lb}{hr} \times \frac{7000gr}{lb}\right) \div 19{,}949{,}371\frac{dscf}{hr} = 0.003gr/dscf$$

Calculated emissions are below the rule limit. It can be assumed the emissions from all these turbines will not exceed the allowable 0.3 gr/dscf. Therefore compliance with Rule 2.11 is expected and a permit condition will be listed on the permit as follows:

- Particulate matter emissions shall not exceed 0.003 gr/dscf in concentration. [District Rule 3.4]

Rule 2.12 Specific Contaminants

Pursuant to Section 2.12 a. a person shall not discharge into the atmosphere from any source, sulfur compounds calculated as sulfur dioxide (SO_2), in any state or combination thereof, in excess of 0.2%, by volume at standard conditions.

i. C-08-267 (Boiler)

$$SOx\% = \frac{SOx\ lb}{hr} \times \frac{1\ day}{24\ hr} \times MV \times \frac{1}{MWSO2} \times \frac{1}{BR} \times \frac{1}{FF} \times 100\%$$

Where:

SO_x emission rate = 0.5 lb/day
MV = 385 scf/mole
$MWSO_2$ = 64 lb/mole
BR = 37 MMBtu/hr
FF = 8,710 scf/MMBtu

$$SOx\% = \frac{0.5\ lb}{hr} \times \frac{1day}{24\ hr} \times \frac{385\ scf}{mole} \times \frac{mole}{64\ lb} \times \frac{hr}{37\ MMBtu} \times \frac{MMBtu}{8{,}710} \times 100\% = 0.00004\%$$

0.00004% ≤ 0.2%, therefore the boiler is expected to comply with the rule.

ii. C-08-268 (Diesel emergency IC engine)

$$SOx\% = \frac{SOx\ lb}{hr} \times MV \times \frac{1}{MWSOx} \times \frac{hr}{60\ min} \times \frac{1}{scfm} \times 100\%$$

Where:

SO_x emission rate = 0.02 lb/hr
MV = 385 scf/mole
$MWSO_2$ = 64 lb/mole
scfm = 2,797.1

$$SOx\% = \frac{0.02\ lb}{hr} \times \frac{385\ scf}{mole} \times \frac{mol}{64\ lb} \times \frac{hr}{60\ min} \times \frac{min}{2{,}797.1\ scf} \times 100\% = 0.0001\%$$

0.0001% ≤ 0.2%, therefore the emergency IC engine is expected to comply with the rule.

iii. C-08-269 (Diesel emergency fire pump IC engine)

$$SOx\% = \frac{SOx\ lb}{hr} \times MV \times \frac{1}{MWSOx} \times \frac{hr}{60\ min} \times \frac{1}{scfm} \times 100\%$$

Where:

SO_x emission rate = 0.004 lb/hr
MV = 385 scf/mole
$MWSO_2$ = 64 lb/mole
scfm = 468.2

$$SOx = \frac{0.004\ lb}{hr} \times \frac{385\ scf}{mole} \times \frac{mole}{64\ lb} \times \frac{hr}{60\ min} \times \frac{min}{468.2\ scf} \times 100\% = 0.0001\%$$

0.0001% ≤ 0.2%, therefore the emergency fire pump IC engine is expected to comply with the rule.

iv. C-08-271 (Turbines)

$$SOx\ \% = \frac{SOx\ lb}{hr} \times MV \times \frac{1}{MWSO2} \times \frac{1}{FH} \times \frac{1}{HHV} \times \frac{1}{FD} \times 1e^6 \times 100\%$$

Where:

SO_x emission rate = 6.44 lb/hr
MV = 385 scf/mole
MW SO_2 = 64 lb/mole
FH = 2,327 MMBtu/hr
HHV = 1,033 BTU/scf
FD = 8,573 dscf/MMBtu

$$SOx\% = \frac{6.44\ lb}{hr} \times \frac{385\ scf}{mole} \times \frac{1\ mole}{64\ lb} \times \frac{1\ hr}{2327\ MMBtu} \times \frac{1\ MMBtu}{8{,}573\ dscf} \times e^{6} \times 100\% = 0.19\%$$

0.19% ≤ 0.2%, therefore the turbines are expected to comply with the rule.

Rule 2.16 Fuel Burning Heat or Power Generators

This rule limits air contaminants from fuel burning equipment, specifically "the number of boilers, furnaces, jet engines, or other fuel burning equipment which are used for the production of useful heat or power".

i. C-08-267 (Boiler)

District Rule 2.16 Limits			
Pollutant	**NO_x**	**Total PM**	**SO_2**
C-08-267 (lb/hr)	0.17	0.12	0.02
Rule Limit (lb hr)	140	40	200

The table above indicates compliance with the maximum lb/hr limit in this rule; therefore continued compliance is expected.

ii. C-08-268 (Diesel emergency IC engine) and C-08-269 (Diesel emergency fire pump IC engine)

Rule 2.16 does not apply to the affected equipment and no further discussion is required.

iii. C-08-271 (Turbine)

District Rule 2.16 Limits			
Pollutant	**NO_x**	**Total PM**	**SO_2**
C-08-271 (lb/hr)	140	9.0	7.1
Rule Limit (lb hr)	140	40	200

The table above indicates compliance with the maximum lb/hr limit in this rule; therefore continued compliance is expected.

Rule 2.19 Particulate Matter Process Emission Rate

The rule establishes PM emission limits as a function of process rate in tons/hr. Gas and liquid fuel are excluded from the definition of process weight. Therefore this rule does not apply to any of the permit units associated with this project, and no further discussion is required.

Rule 2.27 Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

Pursuant to Section 102, this rule applies to the proposed boiler being permitted under C-08-267.

The unit is natural gas fired with a maximum heat input of 37.0 MMBtu/hr.

Section 301 requires that NO_x and CO emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3% oxygen.

Rule 2.27 Emission Limits				
Category	**Operated on gaseous fuel**		Operated on non-gaseous fuel	
	NO_x Limit	CO Limit	NO_x Limit	CO Limit
Units w/rated heat input ≥5MMBtu/hr and annual heat inputs ≥90,000 therms	30 ppmv, or 0.036 lb/MMBtu of heat input	≤400 ppmv	40 ppmv, or 0.052 lb/MMBtu of heat input	≤400 ppmv

The proposed NOx emission factor is 9 ppmv@ 3% O_2 (0.011lb/MMBtu) and CO emission factor is 50 ppmv@ 3% O_2 (0.037 lb/MMBtu).

Compliance with Section 300 is expected and a permit condition listing the emission limits will be included on the permit as follows:

- Emission concentrations from this unit shall not exceed any of the following limits:

  VOC (as methane) - 10.0 ppmvd @ 3% O2;
  CO - 50.0 ppmvd @ 3% O2;
  NOx (as NO2) - 9.0 ppmvd @ 3% O2 ;
  SOx (as SO2) - 0.0014 lb/MMBtu, or

PM10 - 0.0075 lb/MMBtu; [District Rule 3.4]

Section 302 is applicable to units with rated heat inputs ≤5 MMBtu/hr. Since the unit's rated heat input exceeds this limit, the requirements of this section do not apply.

Section 303.1 is a requirement for units which simultaneously fire combinations of gaseous and non-gaseous fuel. The proposed unit will be permitted for gaseous fuel only, with a condition as follows:

- The unit shall only be fired on Public Utility Commission (PUC) grade natural gas. [District Rule 3.4]

Section 303.2 requires operators of units which employ flue-gas NO_x reducing technology to either perform a source test on a yearly basis or install data collection devices to collect sufficient data consistant with determining compliance with this rule. The facility has not proposed to employ flue-gas NOx reducing technology, therefore this section is not applicable.

Section 402.1 requires that the operator of any unit shall have the option of complying with either the lb/MMBtu emission rates or the ppmv emission limits. The District will require that the yearly Source Test Protocol identify which basis (lb/MMBtu or ppmv) will be used to determine compliance.

Section 402.2 requires that all emission determinations shall be made with the unit operating at either normal representative conditions or conditions specified on the permit to operate. No compliance determination can be made within two hours after a continuous period in which there has been no fuel flow to the unit, or is shut off for thirty minutes or longer. Therefore the following condition will be listed on the permit:

- All emission determinations shall be made in the as-found operating condition, except that emission determinations shall include at a minimum at least one source test conducted at the maximum firing rate allowed by the District permit, and no compliance determination shall be established within two hours after a continuous period in which fuel flow to the unit is zero, or shut off, for thirty minutes or longer. [District Rule 2.27 §402.2]

Section 402.5 lists requirements for portable analyzer testing. Since the applicant does not use a portable analyzer to satisfy the monitoring requirements of this rule this section's requirements do not apply.

Section 402.6 requires that all units covered under the emissions limit section conduct a source test to demonstrate initial compliance and specifies that additional source testing may be required by the APCO to ensure on-going compliance with the emissions limits. Therefore the following conditions will be listed on the permit:

- Source testing to measure VOC, CO and NOx emissions from this unit shall be conducted within 60 days of initial start-up. [District Rule 3.4]

- Source testing to measure VOC, NOx and CO emissions from this unit shall be conducted at least once every twelve (12) months. [District Rule 3.4]

Section 402.7 requires source tests or tune-ups be performed in accordance with applicable rule section. The District will list the appropriate test methods per rule Section 502.

Section 403 requires owners/operators of units subject to the emissions limits in this rule submit the appropriate source test or tune-up reports at least every 12 months, therefore the permit to operate will list the following condition:

- The District must be notified prior to any compliance source test, and a source test protocol must be submitted for approval 14 days prior to testing. The results of the source test shall be submitted to the District within 60 days of the test date. The protocol and report shall be mailed to the attention of the Supervising Air Quality Engineer. [District Rule 3.4]

Section 501 requires owners/operators to monitor and record fuel usage and hours of operation during start up and shut down. Therefore the District will list the following condition on the permit to operate:

- The Permit Holder shall monitor and record the cumulative daily, quarterly and annual natural gas fuel usage (in cubic feet) from the totalizing meter and the cumulative annual hours of operation during start-up and shut-down procedures. [District Rules 2.27, 3.4, and 40 CFR 60.48(c)(g)]

Section 502 identifies test methods to be used for demonstrating compliance with the permitted emissions limits. The following condition will be listed on the permit to operate:

- Source testing shall be conducted using the following test methods [District Rule 3.4]:
  a. VOC – EPA Method 18;
  b. CO - EPA Method 10, or CARB Method 100;
  c. NOx (as NO2) - EPA Method 7E, or CARB Method 100;
  d. Stack gas oxygen - EPA Method 3 or 3a, or CARB Method 100; and
  e. Flow rate - EPA Method 19, or CARB Methods 1-4.

Section 600 prescribes requirements for tune-up procedures performed to demonstrate on-going compliance. The facility will be required to source test once every 12 months, therefore this section is not applicable and no further discussion is required.

Rule 2.32 Stationary Internal Combustion Engines

This rule is only applicable to C-08-268 (Diesel emergency IC engine) and C-08-269 (Diesel emergency fire pump IC engine).

The purpose of the rule is to limit the emissions of NO_x and CO from internal combustion engines and applies to any IC engine with a rated brake horse-power greater than 50 horsepower.

Pursuant to Section 110.3, except for Section 503, the requirements of this rule do not apply to an IC engine that is an emergency standby engine operated either during an emergency or maintenance operation, and which maintenance operation is limited to 50 hours per calendar year. As such, both of the above mentioned emergency standby IC engines are exempt from the provisions of this rule, except the recordkeeping requirements of Section 503. These recordkeeping requirements are superseded by the more stringent recordkeeping requirements in the State's Airborne Toxic Control Measure for Stationary Compression-Ignition Engines.

Rule 2.34 Stationary Gas Turbines

Rule 2.34 is applicable to all stationary gas turbines, 0.3 megawatt and larger. The proposed gas turbines are approximately 200 MW each, therefore the rule is applicable.

Section 300 limits the NO_x emissions from stationary gas turbines greater than 10 MW and equipped with Selective Catalytic Reduction (SCR) excluding during the thermal stabilization period. The rule NO_x compliance limit (ppm@ 15% O_2) is 9 x EFF/25.

Where:

EFF (Turbine efficiency) = (3412 x 100%)/AHR

AHR (Actual Heat Rate) = 10,117 BTU/KW-hr (from applicant's supplemental information)

EFF = (3412 x 100%)/10,117 = 33.7%

NO_x limit = 9 x 33.7/25 = 12 ppm @ 15% O_2 while operated under load conditions.

This emission concentration shall not apply during 1) periods of thermal stabilization and 2) periods when the unit is not under load conditions (e.g. not supplying power to the utility grid). The rule does not offer relief from the NO_x limit during the plant's shutdown, therefore the turbines are expected to comply with the NO_x limit during shutdown periods when the plant is still supplying power to the utility grid. As required by Section 300 the NO_x limit must be averaged over a 15 minute period.

For normal loaded operations (not including periods of start-up and thermal stabilization, or shut down), the source has proposed to comply with a 3-hour rolling average NO_x limit of 2.0 ppmv @ 15% O_2, therefore compliance with Section 300 is expected. Under the New Source Review requirements the plant will be allowed to exceed the permitted 3-hour rolling average limit during 1) start-up and thermal stabilization periods, and 2) shutdown periods. Section 216 requires the thermal stabilization of turbines during start-up to not exceed a time period of two hours per occurrence. The District has made the determination that this limit was written for simple cycle power generators. The proposed system is combined cycle and this newer technology cannot safely achieve thermal stabilization in the required two hour time frame. The District has begun rule development efforts to amend Rule 2.34 to include a separate thermal stabilization limit for combined cycle systems of 6 hours. As a result, the PDOC will be issued assuming the rule change is promulgated and approved before the plant is built. The ATC will have a condition limiting thermal stabilization during startup to comply with the version of District Rule 2.34 that is in effect at the time of operation, as follows:

- The turbine startup periods shall comply with District Rule 2.34 startup/thermal stabilization period requirements that are in effect at the time the facility begins operations. [District Rule 3.4]

Section 400 pertains to facilities becoming rule compliant by 1998 and exempt or emergency standby units and therefore does not apply to these units.

Section 501 requires the facility to install, operate and maintain in calibration equipment, as approved by the APCO, that continuously measures and records control system operating parameters, elapsed time of operation, and the exhaust gas NO_x concentrations corrected to 15% o_2. The NO_x monitoring system shall meet EPA requirements as specified in 40 CFR Part 60, App. B, Spec. 2 or other systems that are acceptable to EPA. The following condition will ensure continued compliance with the requirements of this section:

- The owner/operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records control system operating parameters, elapsed time of operation, exhaust gas NO_x, CO, O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during start-ups and shut downs, provided the CEMS pass the relative accuracy requirement for startups and shutdown specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMs results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 2.34, 3.4 and 40 CFR 60.4335(b)(1)]

Section 502 requires records:

a. be made available upon request and be retained for two years;
b. be submitted to the APCO demonstrating that the system has data gathering and retrieval capability;
c. be submitted to the APCO prior to issuance of a PTO, which correlates the control system operating parameters to the associated NO_x output.. This information may be used by the APCO to determine compliance

when there is no CEMs for NO_x available or the CEMs is not operating properly;

d. of source test information be provided annually regarding the exhaust gas NO_x concentration @ 15% O_2, and the demonstrated percent efficiency (EFF) of the turbine units;
e. of a gas turbine log that includes, on a daily basis, the actual Pacific Standard Time start-up and stop time, total hours of operation, type and quantity of fuel used. This information shall be available for inspection at any time from the date of entry;

The following conditions will ensure continued compliance with this section:

- The Permit Holder shall submit to the District information correlating the NO_x control system operating parameters to the associated measured NO_xoutput. The information must be sufficient to allow the District to determine compliance with the NO_x emission limits of this permit during times that the CEMs is not functioning properly. [District Rule 2.34]

- The Permit Holder shall maintain the following records: date and time, duration, and type of any start-up, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rule 2.34, District Rule 3.4, and 40 CFR 60.8(d)]

- The Permit Holder shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NO_x mass emissions (lb/hr and lb/twelve month rolling period). [District 3.4]

Section 503 specifies the following source test methods to be used:

1) Oxides of Nitrogen (NO_x): Oxides of Nitrogen (NO_x) emissions shall be determined in accordance with EPA Method 20.
2) Oxygen (O_2): Oxygen (O_2) concentrations shall be determined in accordance with EPA Method 3A.
3) HHV and LHV: HHV and LHV shall be determined in accordance with ASTM D-240-87, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, or D-2382-88, Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High Precision Method),

for distillate fuels, and ASTM 3588-91 Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels, ASTM D-1826-88, Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, or ASTM D-1945-81, Standard Method for Analysis of Natural Gas by Gas Chromatography, for gaseous fuels.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used:
  VOC – EPA Method 18 or 25;
  CO – EPA Method 10 or 10B;
  NO_x - EPA Method 20;
  PM_{10} – EPA Method 5 (front half and back half) or 201 and 202a;
  Ammonia – BAAQMD ST – 1B;
  O_2 – EPA Method 3A. [District Rule 2.34 and 40 CFR 60.4400(1)(i)]

Rule 3.1 General Permit Requirements

The rule requires any person building, erecting, altering, or replacing any facility, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By submitting applications for authorities to construct CPV Vaca Station Project is complying with the requirements of this rule.

In addition, the following conditions have been added for the turbines (C-08-271) to ensure compliance with the requirements of this rule:

- Any violation of any emission standard to which the stationary source is required to conform, as indicated by the records of the monitoring device, shall be reported by the operator of the source to the District within 96 hours after such occurance. [District Rule 3.1§405.4]

Rule 3.4 New Source Review

The rule applies to all new stationary sources and emissions units therefore it applies to each of the emission units.

Section 301 Best Available Control Technology (BACT) requirements are triggered on a pollutant by pollutant basis and on an emissions unit by emissions unit basis for the following:

a. Any emissions unit with a potential to emit exceeding:

i.	Reactive organic compounds	10 lb/day
ii.	Nitrogen Oxides	10 lb/day
iii.	Sulfur oxides	80 lb/day
iv.	PM_{10}	80 lb/day
v.	Carbon monoxide	250 lb/day
vi.	Lead	3.3 lb/day

b. The emissions triggers major modification requirements.

1. BACT Applicability

i. C-08-267 (Boiler)

As seen in Section C.2.i of this evaluation, the applicant is proposing to install a new boiler with a potential to emit that does not trigger BACT for any of the criteria pollutants.

ii. C-08-268 (Diesel IC engine powering an electric generator)

As seen in Section C.2.ii of this evaluation, the applicant is proposing to install a new diesel fired IC engine with a potential to emit greater than the trigger level for NO_x.

iii. C-08-269 (Diesel IC engine powering fire water pump)

As seen in Section C.2.iii of this evaluation, the applicant is proposing to install a new diesel fired IC engine with a potential to emit greater than the trigger level for NO_x.

iv. C-08-270 (Cooling Tower)

As seen in Section C.2.iv of this evaluation, the applicant is proposing a new 12 cell mechanical cooling tower with a potential to emit that does not trigger BACT for any pollutant.

v. C-08-271 (Turbines)

As seen in Section C.2.v of this evaluation, the applicant is proposing to install two new combustion turbine generators with potential emissions greater than the trigger levels for VOC, CO, NO_x, SO_x. and PM_{10}.

2. Top Down BACT Analysis

Per District Policy BACT Guidelines, a Top-Down BACT analysis shall be performed as a part of the application review process for each application subject to BACT requirements pursuant to the District's NSR Rule. The BACT analysis will evaluate available control technologies and methods that have been achieved in practice for such emissions unit class of source, or are contained in any SIP approved by the EPA for such category and class of source, or any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source. See Appendix E for the BACT analysis for C-08-268, C-08-269, and C-08-271.

3. BACT Summary

i. C-08-268 (Diesel IC engine powering an electric generator)

BACT has been satisfied by the following

NO_x EPA Certified NO_x emissions of 4.8 gr/hp-hr

ii. C-08-269 (Diesel IC engine powering fire water pump)

BACT has been satisfied by the following

NO_x EPA Certified NO_x emissions of 3.0 gr/hp-hr

iii. C-08-271 (Turbines)

BACT has been satisfied by the following:

VOC 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during start-up/shutdown) with good combustion practices and an oxidation catalyst and natural gas fuel.

CO: 3.0 ppmv @ 15% O_2 (3-hour rolling average, except during start-up/shutdown) with good combustion practices and an oxidation catalyst and natural gas fuel.

NO_x: 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during start-up/shutdown) with Dry Low NO_x Combustors, SCR with ammonia injection and natural gas fuel.

SO_x Use of Public Utility Commission regulated natural gas fuel.

PM_{10} Air inlet filtration, lube oil coalesce, and natural gas fuel.

Section 302 Emission Offset Requirements (ERC) are triggered on a pollutant by pollutant basis and is required when the affected pollutant emission increase exceeds the following levels:

Reactive organic compound	7,500 lb/quarter
Nitrogen oxides	7,500 lb/quarter
Sulfur oxides	13,650 lb/quarter
PM_{10}	13,650 lb/quarter
Carbon Monoxide	49,500 lb/quarter

1. ERC Applicability

As seen in the tables below, the facility's potential to emit is greater than the offset thresholds for VOC, CO, NO_x, and PM_{10}, emissions, therefore offsets are required.

VOC Offset Determination				
	1[st] Qtr (lb/quarter)	2nd Qtr (lb/quarter)	3rd Qtr (lb/quarter)	4th Qtr (lb/quarter)
Post Project SSPE ($SSPE_2$)	26,257	25,654	26,502	25,784
Offset Threshold	7,500	7,500	7,500	7,500
Offsets Required?	**Yes**	**Yes**	**Yes**	**Yes**

CO Offset Determination				
	1[st] Qtr (lb/quarter)	2nd Qtr (lb/quarter)	3rd Qtr (lb/quarter)	4th Qtr (lb/quarter)
Post Project SSPE ($SSPE_2$)	101,537	87,087	103,663	101,012
Offset Threshold	49,500	49,500	49,500	49,500
Offsets Required?	**Yes**	**Yes**	**Yes**	**Yes**

NO_x Offset Determination				
	1[st] Qtr (lb/quarter)	2nd Qtr (lb/quarter)	3rd Qtr (lb/quarter)	4th Qtr (lb/quarter)
Post Project SSPE ($SSPE_2$)	78,956	66,940	80,569	77,665

Offset Threshold	7,500	7,500	7,500	7,500
Offsets Required?	**Yes**	**Yes**	**Yes**	**Yes**

SO_x Offset Determination				
	1st Qtr (lb/quarter)	2nd Qtr (lb/quarter)	3rd Qtr (lb/quarter)	4th Qtr (lb/quarter)
Post Project SSPE ($SSPE_2$)	7,187	7,023	7,254	7,057
Offset Threshold	13,650	13,650	13,650	13,650
Offsets Required?	**No**	**No**	**No**	**No**

PM_{10} Offset Determination				
	1st Qtr (lb/quarter)	2nd Qtr (lb/quarter)	3rd Qtr (lb/quarter)	4th Qtr (lb/quarter)
Post Project SSPE ($SSPE_2$)	42,949	42,089	43,396	42,318
Offset Threshold	13,650	13,650	13,650	13,650
Offsets Required?	**Yes**	**Yes**	**Yes**	**Yes**

2. Quantity of Offsets Required:

Per Section 413 and 414 of this rule, the quantity of offsets in pounds per calendar quarter for a stationary source shall be the sum of potential emissions from all emission units.

Per Section 110 emergency equipment that is used exclusively for emergency standby for electrical power generation, emergency water pumping for flood control or fire fighting that does not operate more than 50 hours for maintenance purposes, and is not operated over 200 hours per year, is exempt from providing emission offsets. Therefore permit units C-08-268 and C-08-269 will be exempt from providing offsets and the associated emissions will be subtracted from the facility's potential to emit prior to calculating actual offset amounts.

<u>VOC Offset Calculations:</u>

Pursuant to Section 303, the distance offset ratio for a new major stationary source shall be 1.3:1 if the emissions offsets originated at the same stationary sources as the new or modified emissions unit or within a 15 mile radius; and 1.5:1 if generated greater than 15 miles and less than 50 miles.

The amount of VOC ERCs that need to be surrendered are as follows:

Offsets required = X lb VOC/quarter$_n$ x distance ratio

The calculated offsets can be seen in the table below:

VOC Offsets Required				
Distance Ratio	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
≤ 15 mile radius	34,134	33,350	34,453	33,519
15 ≤ x ≤ 50 mile radius	39,386	38,481	39,752	38,676

The applicant has proposed some combination of the ERC certificates listed in Attachment D to offset the increases in VOC emissions associated with this project. The proposed certificates have available quarterly VOC as follows:

VOC Offset Proposal				
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
Total	188,001	173,052	79,189	213,248

Assuming the worst-case offset ratio of 1.5:1

Project VOC offset requirements:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
VOC emissions to be offset	39,386	38,481	39,752	38,676
Proposed ERCs	188,001	173,052	79,189	213,248
Remaining ERCs	148,615	134,571	39,437	174,572

Remaining VOCs to be Offset	0	0	0	0

As seen above the facility has proposed sufficient evidence of credits to fully offset the quarterly VOC emissions increases associated with this project.

CO Offset Calculations:

Pursuant to Section 303, the distance offset ratio for a new stationary source shall be 1.0:1 if the emission offsets originated at the same stationary source as the new or modified emissions unit; 1.2:1 if the offsets originated within a 15 mile radius of the emissions unit; and 1.5:1 if generated greater than 15 miles and less than 50 miles. This permitting action is for a new major stationary source so the amount of CO ERCs that need to be surrendered is shown in the following table:

CO Offsets Required				
Distance Ratio (mile radius)	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
≤ 15	121,844	104,504	124,396	121,214
15 ≤ x ≤ 50	152,305	130,630	155,494	151,518

The applicant has proposed some combination of the ERC certificates listed in Appendix E to offset the increases in CO emissions associated with this project. The proposed certificates have available quarterly CO as follows:

CO Offset Proposal				
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
Total	1,761,182	1,729,838	581,059	2,180,220

Assuming the worst-case offset ratio of 1.5:1

Project CO offset requirements:

	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
CO emissions to be offset	152,305	130,630	155,494	151,518
Proposed ERCs	1,761,182	1,729,838	581,059	2,180,220
Remaining ERCs	1,608,877	1,599,208	425,565	2,028,702
Remaining COs to be Offset	0	0	0	0

NOx Offset Calculations:

Pursuant to Section 303, the distance offset ratio for a new major stationary source shall be 1.3:1 if the emissions offsets originated at the same stationary sources as the new or modified emissions unit or within a 15 mile radius; and 1.5:1 if generated greater than 15 miles and less than 50 miles.

This permitting action is for a new major stationary source, therefore the amount of NO_x ERCs that need to be surrendered is:

NO_x Offsets Required				
Distance Ratio	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
≤ 15 mile radius	102,643	80,328	104,740	100,964
15 ≤ x ≤ 50 mile radius	118,434	100,410	120,853	116,497

The applicant has stated that the facility plans to use some combination of the ERC certificates listed in Appendix D to offset the increases in NO_x emissions associated with this project.

NO_x Offset Proposal				
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
Total	173,551	174,878	68,940	214,803

Currently, Rule 3.4 Section 302.8 allows NO_x credits generated in the 2nd and 3rd calendar quarters to be used in 1st and 4th calendar quarters. The District plans to amend our offset rule requirements to include the ability to use credits generated in the 2nd or 3rd calendar quarters (ozone season) to be used in any calendar quarter. As a result, the PDOC will be issued assuming the rule change is promulgated and approved before the plant is built. Therefore excess credits from the 2nd quarter could be used in the 3rd quarter to cover the credit deficit.

If a rule change is not adopted and approved by ARB/EPA, the applicant has been advised they will have to find different offsets or modify the emission rates (operating schedule).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NOx emissions to be offset	118,434	100,410	120,853	116,497
ERCs proposed	173,551	174,878	68,940	214,803
2nd Qtr ERCs applied to 3rd qtr	0	-51,913	51,913	0
Remaining ERCs	55,117	22,555	0	98,306
Remaining NOx emissions to be offset	0	0	0	0

As seen above the facility has proposed sufficient evidence of credits to fully offset the quarterly NO_x emissions increases associated with this project.

PM_{10} Offset Calculations:

Pursuant to Section 303, the distance offset ratio for a stationary source shall be 1.0:1 if the emission offsets originated at the same stationary source as the new or modified emissions unit; 1.2:1 if the offsets originated within a 15 mile radius of the emissions unit; and 1.5:1 if generated greater than 15 miles and less than 50 miles. This permitting action is for a new major stationary source therefore the amount of PM_{10} ERCs that need to be surrendered is shown in the following table:

PM_{10} Offsets Required				
Distance Ratio	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
≤ 15 mile radius	51,539	50,506	52,075	50,782
15 ≤ x ≤ 50 mile radius	64,423	63,133	65,094	63,477

The applicant has proposed some combination of the ERC certificates listed in Appendix E to offset the increases in PM_{10} emissions associated with this project. The proposed certificates have available quarterly PM_{10} as follows:

PM_{10} Offsets Proposal				
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
Total	176,786	413,485	168,169	326,117

Assuming the worst-case offset ratio of 1.5:1

Project PM_{10} offset requirements:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} emissions to	64,423	63,133	65,094	63,477

be offset				
Proposed ERCs	176,786	413,485	168,169	326,117
Remaining ERCs	112,363	350,352	103,075	262,640
Remaining PM_{10}	0	0	0	0

Offset Conditions:

The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to construction of C-08-267, the Permit Holder shall provide emission reduction credits for the following quantities of emissions: [District Rule 3.4]

ERCs Generated on Site

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
VOC	181	183	185	185
CO	1,217	1,232	1,243	1,243
NO_x	468	474	478	478
PM_{10}	247	250	253	253

ERCs Generated Within 15 mile Radius

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
VOC	181	183	185	185
CO	1,460	1,478	1,491	1,491
NO_x	468	474	478	478
PM_{10}	297	300	303	303

ERCs Generated Greater than 15 mile and Less Than 50 Miles

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
VOC	209	211	213	213
CO	1,825	1,848	1,864	1,864
NO_x	540	546	551	551
PM_{10}	371	375	379	379

- Prior to construction of C-08-271, the Permit Holder shall provide emission reduction credits for the following quantities of emissions: [District Rule 3.4]

ERCs Generated on Site

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
VOC	33,954	33,167	34,268	33,335
CO	100,320	85,855	102,420	99,769
NO_x	102,175	86,549	104,261	100,486
PM_{10}	35,803	34,863	36,092	35,014

ERCs Generated Within 15 mile Radius

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
VOC	33,954	33,167	34,268	33,335
CO	120,384	103,026	122,904	119,723
NO_x	102,175	86,549	104,261	100,486
PM_{10}	42,964	41,836	43,310	42,016

ERCs Generated Greater than 15 mile and Less Than 50 Miles

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
VOC	39,178	38,270	39,539	38,463
CO	150,480	128,783	153,630	149,654
NO_x	117,894	99,864	120,302	115,946
PM_{10}	53,704	52,295	54,138	52,521

- Prior to construction of C-08-270, the Permit Holder shall provide emission reduction credits for the following quantities of emissions: [District Rule 3.4]

ERCs Generated on Site

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
PM_{10}	6,898	6,975	7,052	7,052

ERCs Generated Within 15 mile Radius

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
PM_{10}	8,278	8,370	8,462	8,462

ERCs Generated Greater than 15 mile and Less Than 50 Miles

Pollutant	1st Qtr (lb)	2nd Qtr (lb)	3rd Qtr (lb)	4th Qtr (lb)
PM_{10}	10,348	10,463	10,578	10,578

- ERC certificate numbers (or any splits from these certificates) as specified in Appendix D shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 3.4]

The PM emissions as proposed will be fully offset with surrendered PM credits. In order to assure compliance with cooling tower PM_{10} mass emissions, the District has added the following conditions to the cooling tower ATC (C-08-270):

- The maximum total dissolved solids for the cooling tower water shall not exceed 9,000 ppm. [District Rule 3.4]
- The Permit Holder shall demonstrate compliance with total dissolved solids concentration limits using a District approved test method within 45 days of startup and once in every twelve month period thereafter. [District Rule 3.4]
- The Permit Holder shall submit compliance demonstration results to the District within 45 days of conducting compliance demonstration. [District Rule 3.4]
- The drift loss associated with the cooling towers shall not exceed 0.0005%. [District Rule 3.4]
- The Permit Holder shall use only rust inhibiting products that do not contain VOCs. [District Rule 3.4]
- No visible emissions, excluding steam, beyond property boundaries are permitted. [District Rule 3.4]

The District has added the following conditions to the turbines (C-08-271) to ensure compliance with District Rule 3.4, New Source Review:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality

Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing and 40 CFR Part 60. [District Rule 3.4; 40 CFR Part 60]

- The mass emissions from the CTGs (including periods of start-up and shutdown) shall not exceed the daily, quarterly, or annual values listed in the PERMITTED EMISSION LIMITS table [District Rule 3.4 §409.2(b)]

- The turbine commissioning periods shall not exceed 415 hours of operation per turbine and the emissions during the commissioning period will accrue towards the maximum annual emissions limits. [District Rule 3.4]

- During commissioning, exhaust emission rates from each unit shall not exceed any of the following limits: VOC (as methane) – 163.8 lb/hr; CO – 3812.6 lb/hr; NO_X (as NO_2) – 140 lb/hr; SO_X (as SO_2) – 7.13 lb/hr; and PM_{10} – 12.8 lb/hr. [District Rule 3.4]

- The quarterly and annual average of the sulfur content of the CTG shall not exceed 0.25 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 3.4]

- The Permit Holder shall install and maintain a District approved fuel flow meter in order to record the fuel heat input rate to the turbines. [District Rule 3.4]

- The Permit Holder shall analyze the fuel's higher heating value (wet basis) on a quarterly basis. [District Rule 3.4]

- The Permit Holder shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The Permit Holder shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 3.4]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 3.4]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 3.4]

- Each unit shall not exceed the following limits when operating with duct burner firing: 1,134 hrs/1st qtr; 700 hrs/2nd qtr; 990 hrs/3rd qtr; 630 hrs/4th; and 3,454 hrs/yr. [District Rule 3.4]

- Each unit shall not exceed the following limits when operating without duct burner firing: 1,026 hrs/1st qtr; 1,484 hrs/2nd qtr; 1,218 hrs/3rd qtr; 1,578 hrs/4th; and 5,306 hrs/yr. [District Rule 3.4]

- During start-up and shutdown, exhaust emission rates from each unit shall not exceed any of the following limits: NO_X (as NO_2) – 140 lb/hr; CO – 500 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 7.5 lb/hr; SO_X (as SO_2) – 5.27 lb/hr; or NH_3 – 12.78 lb/hr. [District Rule 3.4]

- Each unit shall not exceed 365 hours per year when operating in startup shutdown mode. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rule 3.4]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 3.4]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 3.4]

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 3.4]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 3.4]

- The Permit Holder shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction. [District Rule 3.4]

The District has added the following conditions to the boiler (C-08-267) to ensure compliance with District Rule 3.4, New Source Review:

- The Permit Holder shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 3.4]

- The Permit Holder's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 3.4]

- No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 3.4]

- All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 3.4]

The District has added the following conditions to the emergency engines (C-08-268 and C-08-269) to ensure compliance with District Rule 3.4, New Source Review:

- The exhaust stack shall have a minimum height of 40 ft. and shall be oriented vertically. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 3.4]

- The Permit Holder shall not operate the IC engine more than 200 hours per calendar year. [District Rule 3.4, §110.2]

- The Permit Holder shall not operate the IC engine for the supplying of power to a serving utility for distribution on the grid. [District Rule 3.4, §110.3]

- The Permit Holder's operation of the IC engine for reasons other than maintenance and testing purposes shall be limited to actual interruptions of electrical power by the serving utility. [District Rule 3.4, §110.4]

Rule 3.8 Federal Operating Permits

This project will be subject to Rule 3.8 (Title V) because it will meet the following criteria specified in Section 102:

- Section 102.1 states, "A major source." The facility will be a major source for VOC, CO and NO_X after this project.

- Section 102.2 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.

- Section 102.5 states, "Any source that is subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.

Pursuant to Rule 3.8 Section 402.1.a.ii CPV Vaca Station must submit a Title V application within 12 months of commencing operations. No action is required at this time.

The following condition will assure compliance with this rule:

- The Permit Holder shall submit an application to comply with District Rule 3.8 - Federal Operating Permits within twelve months of commencing operation. [District Rule 3.8]

Rule 3.20 Ozone Transport Mitigation

The rule applies to all applications for Authority to Construct submitted pursuant to Rule 3.1 General Permit Requirements, which are deemed complete after December 8, 2004, and which are subject to Rule 3.4 New Source Review. The rule requires "no net increase" for applicable applications and is triggered on a pollutant by pollutant basis. Mitigation is to be provided if the post-project SSPE equals or exceeds 20,000 lb/year of either VOC or NO_X.

The facility's proposed emissions do exceed these trigger levels, however per the specified calculational methodology, the required mitigation will be satisfied by the ERCs required to be submitted for 3.4.

Rule 3.23 Acid Deposition Control

Per Rule 3.23 and 40 CFR Part 72 the proposed CTG's are subject to the acid rain program. As such, Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the facility expects to generate electricity. The facility anticipates beginning commercial operation in 2012 or later.

The acid rain program requirements for this facility will include monitoring the NO_X and SO_X emissions and submission of SO_X allowances (from a national SO_X allowance bank) as well as the use of a NO_X CEM.

CPV Vaca Station submitted an Acid Rain permit application to the District. No further discussion of this rule is required.

Rule 5.2 Upset Breakdown Conditions

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

The requirements of this Rule will be included in the permit for the turbines (C-08-271):

- The Permit Holder shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 5.2 and 3.4]

- The District shall be notified in writing within one week following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 5.2]

Rule 9.3 Hexavalent Chromium

The rule prohibits the use chromium containing compounds in the treatment of cooling tower circulating water. The following condition shall be added to the cooling tower operating permit in order to assure compliance:

- The Permit Holder shall not use or allow the use of chromium containing compounds in the treatment of cooling tower circulating water. [District Rule 9.3 §c.1.]

<u>40 CFR 60 – Subpart Dc Standards of Performance for Fossil Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971</u>

NSPS Subpart Dc applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for SO_X and PM_{10}. Therefore, the boiler proposed under C-08-267 meets the applicability requirements of this subpart.

60.42c – Standards for Sulfur Dioxide

Since coal is not combusted by the boiler in this project, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter

The boiler is not fired on coal, does not combust mixtures of coal with other fuels, does not combust wood, does not combust mixtures of wood with other fuels or oil; therefore it will not be subject to the requirements of this section.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.46c – Emission Monitoring for Sulfur Dioxide

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.47c – Emission Monitoring for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the unit is not subject to §60.42c or §40.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO_2 emissions.

Section 60.48 c (g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be added to the permit to assure compliance with this section.

- A dedicated non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rule 3.4 and 40 CFR 60.48 (c)(g)]

- The Permit Holder shall maintain daily, quarterly, and annual records of the quantity of fuel combusted by the boiler. [District Rules 3.4 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 2.27 requires that records be kept for five years.

<u>40 CFR Subpart GG - Standards of Performance for Stationary Gas Turbines</u>

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. CPV Vaca Station has indicated that the installation and construction of the proposed turbines will be completed sometime after 2012. Therefore, the turbines proposed under C-08-271 meet the applicability requirements of this subpart.

However, 40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed below, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

<u>40 CFR 60 - Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines</u>

40 CFR Part 60 Subpart IIII applies to all owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

1) Manufactured after April 1, 2006, if not a fire pump engine.

2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engines will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable standards of this subpart are less restrictive than current District requirements. The proposed engines will be required to comply with all current District standards so further discussion is not required.

<u>40 CFR 60 – Subpart KKKK</u>

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating greater than 2,000 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

<u>Section 60.4320 - Standards for Nitrogen Oxides:</u>

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

CPV Vaca Station is proposing a NO_X emission concentration limit of 2.0 ppmvd @ 15% O_2 for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_X emission requirements of this subpart. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as

NO2) NOx (as NO2) – 18.75 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 6.52 lb/hr and 2.0 ppmvd @ 15% O2; CO – 17.12 lb/hr and 3.0 ppmvd @ 15% O2; PM10 – 9.00 lb/hr; or SOx (as SO2) – 7.13 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 3.4]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 15.87 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 5.52 lb/hr and 2 ppmvd @ 15% O2; CO - 14.49 lb/hr and 3.0 ppmvd @ 15% O2; PM10 – 7.5 lb/hr; or SOx (as SO2) – 6.04 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 3.4]

Section 60.4330 - Standards for Sulfur Dioxide:

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or

(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

CPV Vaca Station is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The CTGs shall be fired exclusively on PUC natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 3.4 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance. CPV Vaca station does not propose to use water or steam injection therefore; the requirements of this section are not applicable to the turbines in this project.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring

CPV Vaca Station has proposed to install a CEMS system as described in §§60.4335(b) and 60.4345 therefore; the following condition will ensure continued compliance with the requirements of this section:

- The Permit Holder shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 3.4 and 40 CFR 60.4340(b)(1)]

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

CPV Vaca Station will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, CPV Vaca Station is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2) or 40 CFR Part 75, whichever is more stringent, as determined by the District. Alternatively, the CEMS shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 3.4 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 3.4 and 40 CFR 60.4345(b)]

Section 60.4350 – CEMS Data and Excess NO_X Emissions:

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

CPV Vaca Station is proposing to monitor the NO_X emissions rates from the turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 3.4]

<u>Section 60.4355 – Parameter Monitoring Plan:</u>

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, CPV Vaca Station is proposing to install CEMS on each of these turbines that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

<u>Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:</u>

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

CPV Vaca Station is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. The natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 0.25 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be once per calendar quarter. If the result of any quarterly monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 3.4 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, CPV Vaca Station is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. CPV Vaca Station is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

CPV Vaca Station will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. CPV Vaca Station is required to maintain records and submit reports in accordance with the requirements specified in these sections, therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The Permit Holder shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 3.4 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set forth the requirements for the methods that are to be used during source testing.

CPV Vaca Station will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates and concentrations (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve consecutive months thereafter. [District Rule 3.4]

- Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve consecutive months thereafter. [District Rule 3.4]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 3.4 and 40 CFR 60.4400(1)(i)]

- Source testing to measure startup NOx, CO, and VOC mass emission rates and concentrations shall be conducted for the gas turbines prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 3.4]

- Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 3.4]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). CPV Vaca Station has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section.

Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets forth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, CPV Vaca Station is proposing to install a CEMS system to monitor the NO_X emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

CPV Vaca Station is not proposing to determine the sulfur content using any other method, therefore the fuel's sulfur content will be determined using the methods specified above. The proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. CPV Vaca Station is not proposing to measure the SO_2 in the exhaust stream of the turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

California Environmental Quality Act (CEQA)

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b)). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 3.1) and New Source Review Rule (Rule 3.4), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with

District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h).

California Health & Safety Code, Section 42301.6 (School Notice)

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.
2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.
3. The district issues a permit authorizing construction or operation of the new facility.

As discussed in the compliance section for District Rule 2.5 Nuisance, a health risk screening was performed and the results showed that the emissions from the proposed equipment may cause or contribute significantly to a violation of the State and National PM_{10} ambient air quality standards. To mitigate the increase of PM_{10} emissions from the proposed project the facility has agreed to fully offset the PM_{10} increase. Therefore this project qualifies for exemption per the above exemption criteria .

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

The requirements of this section are only applicable to C-08-268 and C-08-269.

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 2.32 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engines involved with this project are new stationary diesel-fueled CI emergency standby engines, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATCs to ensure compliance:

- Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rule 3.4 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engines are not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;
c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

    I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
    II. Amount of fuel purchased;
    III. Date when the fuel was purchased;
    IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
    V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engines powering a water pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association

(NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

The Permit Holder shall maintain a monthly log of usage that shall list and document the nature of use for each of the following:

a) Emergency use hours of operation;
b) Maintenance and testing hours of operation;
c) Hours of operation for emission testing to show compliance with Title 17 CCR, Section 93115.6(a)(3) and 93115.6(b)(3);
d) Initial start-up hours;
e) Hours of operation to comply with the requirements of NFPA 25; and
f) Fuel use through the retention of fuel purchase records which indicate that the fuel used in the IC engine is CARB certified diesel fuel or an approved ATCM compliant alternative fuel. [District Rule 3.4 and Title 17 CCR, Section 93115.10(g)(1)]

The proposed new emergency diesel IC engines powering the emergency generator is not exempt from the operating hours limitation, therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- The Permit Holder shall maintain a monthly log of usage that shall list and document the nature of use for each of the following:

  a) Emergency use hours of operation;
  b) Maintenance and testing hours of operation;
  c) Hours of operation for emission testing to show compliance with Title 17 CCR, Section 93115.6(a)(3) and 93115.6(b)(3);
  d) Initial start-up hours;
  e) Fuel use through the retention of fuel purchase records which indicate that the fuel used in the IC engine is CARB certified diesel fuel or an approved ATCM compliant alternative fuel. [District Rule 3.4 and Title 17 CCR, Section 93115.10(g)(1)]

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 3.4 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a water pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following condition will be listed on the ATC to ensure compliance:

- The Permit Holder shall not operate the IC engine, for maintenance and testing purposes, more than the number of hours necessary to comply with the testing requirements of the NFPA 25, and such operation shall be scheduled in cooperation with the District so as to limit air quality impact. [Title 17 CCR, Section 93115.6(a)(4)(A)(1.)(b.)]

VII. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Preliminary Determination of Compliance for the facility subject to the conditions presented in Attachment A.